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Cost-effectiveness of CECONY Demand Response Programs

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1 Executive Summary

This report presents a comprehensive cost-effectiveness framework that is specific to demand response (DR), reflects how CECONY deploys DR and takes into account the characteristics of CECONY's utility system. A central tenant of the framework is that different DR programs have different characteristics and their value depends on several factors, including: how well DR resources coincide with system and local peaks; performance during reduction events; limits on availability and; limits on maximum event duration. A second tenant of the framework is that the value of DR resources for distribution systems also depends on the characteristics of the distribution area in which the resources are available.

As part of this effort, Freeman, Sullivan & Co. (FSC) developed a DR-specific cost-effectiveness tool and applied it to CECONY's existing DR programs to better understand their value as currently configured and to understand how to improve the value delivered by DR programs. In addition, the cost-effectiveness tool was applied to the CoolNYC pilot, which is focused on testing technology options for controlling room air conditioners.

Because network characteristics directly affect value and the degree to which DR can be used to manage peaks, it was critical to develop a model with sufficient granularity to reflect key differences across CECONY's 64 distinct networks and 19 non-networked distribution areas. These 83 distinct areas were categorized into 8 network groups based on network/non-network status, load shapes, amount of excess capacity and network reliability index (NRI) scores. The cost-effectiveness model allows users to input different demand reduction forecasts, enrollment levels, incentives, costs and benefits for each network type. It also time-differentiates value and takes into account how well DR resources and characteristics coincide with system and local peaks. CECONY's prior cost-effectiveness model did not time-differentiate value or factor in characteristics of different DR programs. It also assumed that the value from DR was similar across all distribution areas.

CECONY's DR programs focus on either shaving peak demand on specific networks or on providing emergency relief. Programs designed for peak shaving, such as the Commercial System Relief Program (CSRP), are activated when the day-ahead forecast is 96% or greater than CECONY's summer system peak that CECONY uses for distribution planning. Most networks tend to peak when CECONY's system loads are high. Programs designed for emergency relief are activated when emergency conditions are met, regardless of demand levels. These include the Distribution Load Relief Program (DLRP) and the residential and small business Direct Load Control (DLC) program.

In applying the cost-effectiveness framework, two key questions were addressed for each program. The first question is whether it is cost effective to continue operation of the program without expansion. This accounts for the fact that, in many instances, equipment and recruitment costs are sunk. The second question is whether adding new participants increases or decreases overall program cost-effectiveness.[1] Both questions are addressed based on how the programs have operated historically, factoring in historical costs, event performance, dispatch practices and program

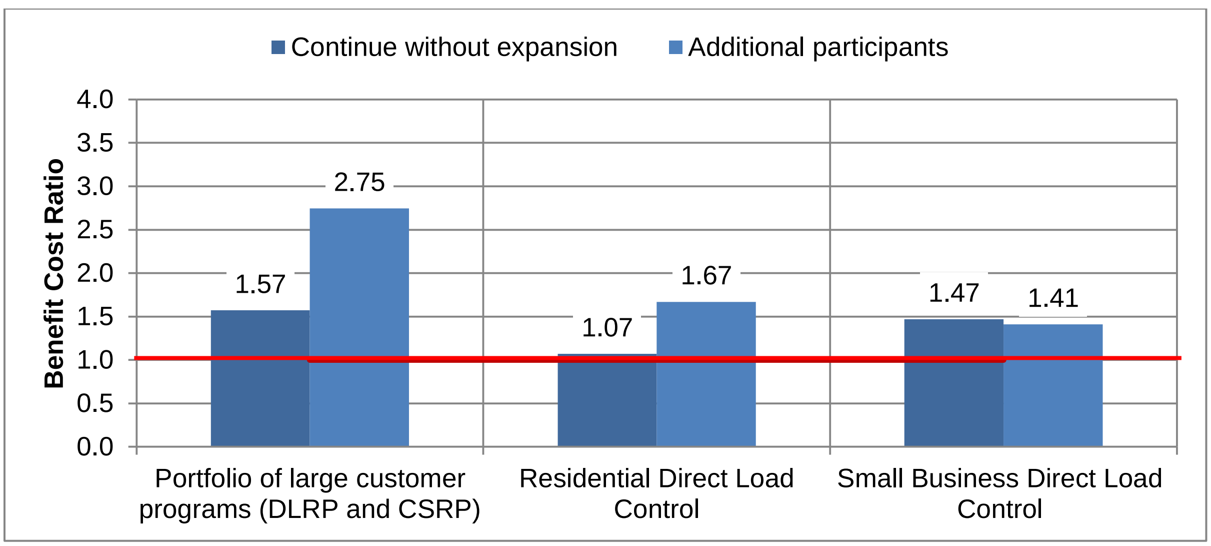
[1] In technical language, this scenario represents the marginal cost-effectiveness of adding additional participants.

rules. In other words, the cost-effectiveness estimates are based on how programs have performed and operated in the past, which could differ from how they might be operated in the future.

An important application of the model is the ability to determine if cost-effectiveness can be improved by adjusting program rules and operations or by more effectively targeting customers. In other words, the model can help assess how changes in program design, marketing strategies and operations impact cost-effectiveness rather than simply modelling programs as currently configured. Key drivers of cost-effectiveness were identified through sensitivity analysis, which involved varying each major input up and down by 20% while holding all other inputs constant. Sensitivity analysis helps identify the assumptions, inputs and program design characteristics that contribute most to net benefits. It also is a useful test of the robustness of the results. A program that is currently cost-effective but becomes cost-ineffective in response to small changes in input values is not very robust, particularly if those input values are uncertain.

Figure 1-1 summarizes the cost-effectiveness results for CECONY's large customer and direct load control programs. The CoolNYC pilot is discussed separately. The figure shows the cost-effectiveness of continuing the programs without expansion and of adding new participants (the two scenarios introduced above). The two large customer programs were analyzed jointly in a portfolio to avoid double counting. The DLRP and CSRP programs both include mandatory and voluntary options and overlap substantially. Overall, 96% of pledged reductions enrolled in CSRP were also enrolled in DLRP, making it difficult to assess the programs separately.

Figure 1-1: Summary of Cost-effectiveness Results[2]



[2] The prior cost-effectiveness model used the utility cost test for DLRP in part because the prior cost-effectiveness TRC test did not include participant unobserved costs. The current framework includes the assumption that participant observed and unobserved costs equal 75% of incentive payments. This is not well grounded empirically, but matches the assumption used for cost-effectiveness analysis in other jurisdictions such as California. These costs are unlikely to be higher than 75%, since customers would not participate in program if their costs exceeded their incentive payments, but they may be much lower.

Four main conclusions can be drawn from the cost-effectiveness analysis summarized in this report. First, while it may be possible to improve program efficiency, given the inputs used here, CECONY's DR programs are cost-effective as currently designed, marketed and operated. Second, increasing program participation would improve the cost-effectiveness of each program. Benefits from new participants more than offset their variable costs without adding to fixed overhead costs. Third, the cost-effectiveness results are robust – that is, the programs are cost-effective from a number of different perspectives and the results do not change from positive to negative when any of the major inputs are adjusted upward or downward by 20%. Finally, the cost-effectiveness of the programs can be improved by targeting recruitment efforts at networks where reductions are most valuable and by reducing the degree of dual enrollment.

Currently, the primary motivation for the CoolNYC pilot is to assess the feasibility of room air conditioner load control and the ability to extend DR opportunities to a broader population. There are over six million room air conditioners in CECONY's service territory, representing approximately 2,500 MW of peak load with significant untapped load management potential. Prior to the CoolNYC pilot, technology used for room air conditioner load control was not generally available. As a pilot, CoolNYC is meant to provide an opportunity to test, learn and optimize room air conditioner load control. It is important to recognize that a substantial amount of innovation is taking place as part of the pilot and that important questions about room air conditioner load control are still being addressed. The purpose of applying the cost-effectiveness tool to CoolNYC is not to assess cost-effectiveness of the pilot, but to better understand what it would take to make control of room air conditioners cost-effective given what is known. Any conclusions about whether or not room air conditioner control can be cost-effective will evolve based on ongoing pilot tests and changes in the technology itself, its costs and the program delivery approach.

A number of scenarios were examined to identify the steps necessary for CoolNYC to become cost-effective. A key aspect of room air conditioner loads is that they are generally smaller than central air conditioners. Consequently, cost-effectiveness is highly sensitive to technology device costs and the magnitude and timing of room air conditioner use relative to peaking conditions at the local level.

It is possible to double the load reduction per room air conditioner unit by targeting customers with larger units that have them on during hours when reductions are most valuable. In addition, more extensive control strategies can increase the percent demand reductions from 22% to somewhere between 30%-40%. The net effect of successfully implementing these two steps would be to triple the average load reduction per device for new participants. Besides better targeting and more extensive control strategies, four additional factors could significantly improve cost-effectiveness if the CoolNYC pilot were to be offered as a program – increasing device plug-in or installation rates, minimizing year to year attrition, increasing event flexibility, and using a combination of one-time sign-up and recurring incentives rather than recurring payments alone (which add up over multiple years). Based on what is known thus far from the pilot, it is possible to design a room air conditioner load control program that yields a net benefit of $78 per device over a 10 year period. Under this scenario, adding approximately 56,000 devices would be sufficient to cover the estimated $585,000 annual overhead fixed costs and lead to a TRC benefit cost ratio of 1.0. Enrollments in excess of 60,000 devices – the break-even point – would lead to a cost-effective program.

2 Project Overview and Background

Since the early 2000's, CECONY has developed and implemented an array of demand response (DR) programs and pilots with the primary goal of providing relief to the distribution system when demands are high or when emergency conditions arise. These DR programs are factored into transmission and distribution planning and, together with other forecasted demand side savings, influence in part the timing and magnitude of transmission and distribution investments. In contrast, most utilities primarily use DR to reduce the need for incremental generation to meet peak demand.

No other utility in the U.S. uses DR as extensively as CECONY for distribution relief. This is due in part to the uniqueness of CECONY's distribution system. About 80% of the load in the CECONY service territory is supplied by underground low-voltage network systems, which are highly reinforced and allow DR to deliver more value than for radial distribution system designs that are more common across the U.S.

This report presents a framework for estimating the cost-effectiveness of CECONY's DR programs. The framework factors in:

- The characteristics of CECONY's DR programs;
- CECONY's use of DR for distribution relief;
- Variation in the concentration of peak demands across different networks;
- The coincidence of DR resources with system, transmission and distribution peaks;
- Overlaps and gaps between CECONY's and NYISO's DR programs; and
- Benefits other than avoided generation and distribution capacity costs.

Cost-effectiveness analysis is critical for comparing different resource options and for optimizing investments in generation, transmission and distribution. When done correctly, it allows for comparisons across resource options and provides a basis for prioritizing investments. A key goal of cost-effectiveness analysis is to provide factual insights, make tradeoffs transparent, improve the planning process and help maximize value. It can also help identify the program design characteristics – e.g., incentive/penalty structures, maximum event duration, speed of response, availability hours, etc. – that contribute most to the value delivered by DR.

There is wide recognition of the need for a DR specific cost-effectiveness framework. FERC's *2010 National Action Plan on Demand Response*[3] (NAPDR) and its *2012 Assessment of Demand Response and Advanced Metering*[4] both acknowledged that a key barrier to DR has been the lack of suitable cost-effectiveness tools. In 2012, as part of the NAPDR development process, FERC organized a working group of experts to develop a framework for evaluating the cost-effectiveness of DR resources.

[3] Available at: http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

[4] Available at: http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

The subsequent report defined DR benefits and costs but also left several key issues unanswered and recommended further areas for research.[5] In particular, the framework did not address three main questions that are central to CECONY's DR programs:

1. *How should the specific characteristics of DR resources be incorporated into valuation?* Different DR programs have different characteristics and adjustments to value need to factor in how well DR resources coincide with system and local peaks, the availability and exhaustibility of the resources, limits on event duration, the total number of hours a resource can be dispatched and the amount of advance notification required.
2. *When, where and how does DR help offset transmission and distribution investments?* It is widely acknowledged that the ability to defer transmission investments through DR is highly dependent on the characteristics of the individual utility system. This often leads to requirements for having the right amount of DR at the right place, with the right availability and the right amount of certainty. However, existing DR frameworks do not consider highly reinforced network systems such as CECONY's and they do not clearly define the specific criteria for DR to provide value in the form of transmission and distribution investments.
3. *How should overlaps between utility and market operator DR programs be accounted for in cost-effectiveness?* Of the total MWs enrolled in CECONY DR programs, 70% are enrolled in NYISO programs. However, NYISO programs focus on providing relief for system peaks while CECONY's programs focus on providing distribution relief based on highly localized peaks and needs. NYISO provides larger incentive payments than CECONY and established its programs earlier. Some customers may not have enrolled in CECONY programs were it not for payments from NYISO and prior experience with DR programs.

This report presents a comprehensive cost-effectiveness framework that is specific to DR, reflects how CECONY deploys DR, and takes into account the characteristics of CECONY's utility system. As part of this effort, FSC developed a DR specific cost-effectiveness tool and applied it to CECONY's existing DR programs to better understand their value as currently configured and to understand how to improve the value delivered by DR programs.

A few steps were fundamental to the development of the framework. FSC met with distribution and transmission operators to assess the circumstances under which they activate different types of DR programs, determine whether DR resources were available when they were needed at specific locations and identify any improvements that could be made to DR to provide additional value. FSC also met with distribution and transmission planners to investigate how DR is incorporated into the planning process and to understand the factors that influence distribution and transmission investments. Another key step was to identify key similarities and differences across CECONY's distribution networks and DR programs that affect value.

2.1 CECONY's Distribution System

CECONY's distribution system delivers power to more than 3 million customers in New York City and Westchester County. The CECONY distribution system covers 660 square miles and contains an estimated population of 9.3 million. The distribution system includes 62 area substations and nearly 2,300 feeders that supply loads. In total, CECONY spends approximately $1.2-$1.3 billion annually in capital and $0.5 billion in O&M costs on its electrical transmission and distribution system in order to

[5] FERC. 2013. *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Cost-effectiveness Working Group. Available at: http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-cost-effectiveness.pdf.

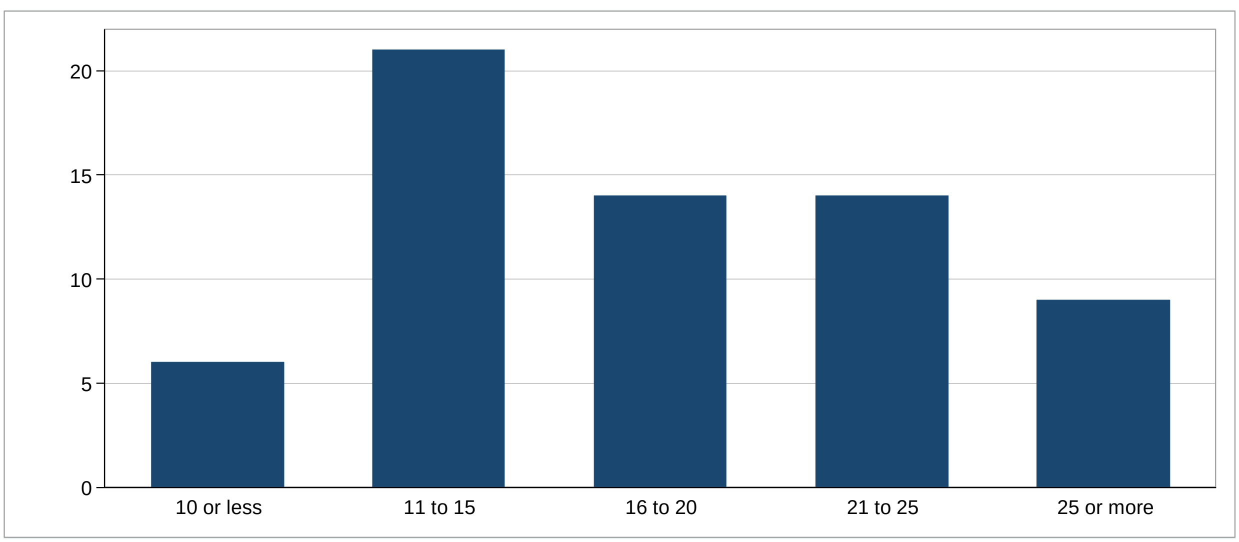
enhance reliability and improve infrastructure. Over 70% of these expenditures are on the distribution system.[6]

Distribution systems are designed to have enough capacity to support peak demands. Most distribution investments are driven by growth in peak demand or are due to aging equipment. Growth related investments involve a combination of large projects that occur infrequently and smaller projects that occur each year. Since upgrades and reinforcement of specific distribution components (e.g., area substations, feeder lines) tend to happen infrequently, a common practice is to install excess capacity when a component is upgraded. The excess capacity helps accommodate additional load growth and can often be utilized when neighboring components are overloaded, thereby improving reliability.

While some components of the distribution system are driven by individual peak demands, a substantial share of distribution system expansion is driven by local, coincident demands that are shared across many customers. If a customer helps reduce *coincident* demand, the unused capacity can accommodate another customer's load growth and avoid or defer investments required to meet that load growth.

About 80% of the load in CECONY's service territory is supplied by 64 underground low-voltage network systems. Each network has between 6 and 29 interconnected feeders and on average serves about 40,000 customers. Figure 2-1 summarizes the number of feeders per network. Approximately 58% of networks have more than 15 feeders. The majority of distribution investment in a given network is driven by the coincident peak for that specific network. The remaining 20% of CECONY's load occurs in 19 load areas supplied by overhead radial distribution systems, typically in neighborhoods where residential customer electricity demand outweighs that of commercial businesses.

Figure 2-1: Number of Feeders per Network



[6] ConED. *2012 Electric Distribution System Manual.* Distribution Engineering.

Underground low voltage networks are generally more reliable than overhead distribution systems. This is mainly due to fundamental differences in design. Unlike many radial systems, failure of any individual distribution feeder on a network does not lead to customer outages because the electricity demand can be met through supply delivered by other feeders. In fact, CECONY networks are designed to continue operating uninterrupted even if the two main components, typically feeders, fail during peaking conditions. This design criteria (N-2), ensures that during peak loading conditions, none of the equipment will be overloaded and no customers will experience any interruption when any two feeders are out of service. However, should multiple feeders become unavailable when demand on a network is high, the risk that the entire network will lose power increases.

The speed of response for contingency operations depends on the timing of when the second major component goes out. If it is earlier in the day, the system typically has enough capacity cushion to continue immediate operations. However, as load increases, the need for load relief becomes more acute. The situation is similar to having two servers at the same restaurant call in sick a few hours before dinner service. If it is a peak day, the backup resources need to be identified and brought in but there is still time to plan for it. The response needs to be swift but not immediate. The situation is different when a second major component goes out as loads are near their peak on the particular distribution network. When that occurs, the need for relief is more acute but still not immediate. It is possible to overload transformers and continue to operate the system, but doing so for a prolonged period of time increases the risk that additional components will fail and can shorten equipment life.

CECONY'S network peaks tend to occur on the hottest days, when both demand levels are high and the likelihood of distribution component failures is highest. Most networks tend to peak on similar days, but the timing of the peak varies from network to network based on the mix of residential and businesses customers.

The magnitude of DR and planning practices also affect ability of DR to translate into concrete avoided distribution investment costs. In order for savings to be realized, DR needs to be incorporated into planning. It also needs to be sufficiently large to influence decisions regarding the timing of major distribution upgrade investments. Distribution investments are characterized by smaller investments that occur annually and major investments that occur less frequently. To defer major investments, reductions from DR and energy efficiency, in combination, need to be sufficiently large to defer the timing of the investments.

2.2 Overview of CECONY DR Programs

CECONY DR programs focus on supporting reliability and reducing costs of operating the electric distribution system. CECONY's dispatch of DR tends to be done on a network by network basis, when load relief is needed due to network contingencies. DR is dispatched only on networks that require load relief and the demand reduction event start times and duration vary from network to network. This is in contrast to most DR programs in the country, which are designed to reduce demand when an entire electric system – such as the one operated by NYISO – peaks.

CECONY's programs focus on either shaving peak demand on specific networks or on providing emergency relief. Programs designed for peak shaving are activated when the day-ahead forecast is 96% or greater than a network's summer system peak used for planning. They include the Commercial System Relief Program (CSRP), Direct Load Control (DLC) and the CoolNYC pilot, which provides CECONY with the ability to turn off window or wall air conditioners (AC) when an event is called. Programs designed for emergency relief are activated under system critical conditions, regardless of demand levels. These include the Distribution Load Relief Program (DLRP) and residential and small business DLC programs. Table 2-1 provides a high level summary of the features of each of CECONY's programs.

The two programs designed for large businesses, DLRP and CSRP, have both mandatory and voluntary options. Customers who sign up for the mandatory option pledge a specific amount of demand reduction. In exchange, they receive monthly payments based on the magnitude of the pledged reduction, regardless of whether or not they are activated, and performance payments when they are activated, but they also face reduced payments and penalties for non-performance. Customers on the voluntary option are only paid based on their performance during program events and do not face penalties.

Performance payments are not payments for energy savings. They are simply a means for rewarding customers for how well they comply with pledged reduction on an event by event basis and are based on capacity value. Put differently, payments for capacity to participants are split between a reservation (or option) payment and a payment that is based on performance for each event.

Table 2-1: CECONY's DR Programs

Program	Purpose	Incentive
Distribution Load Relief Program (DLRP)	Activated by Con Edison in system critical situations (condition yellow or voltage reduction). Customers have two hours notice to begin response for five hour event duration. Premium paid for customers who pre-commit load.	Customers receive a reservation payment of $6.00 or $3.00 per kW pledged and performed, depending on location, and performance payments equal to $0.50 per kWh reduced. Performance only option available for those who do not pre-commit kW.
Residential Direct Load Control (Residential DLC)	Activated by Con Edison in system critical situations and peak shaving events. Con Edison residential, religious and small business (demand less than 100 kW) customers with central air-conditioning. Allows Con Edison to remotely adjust thermostat settings.	Customers will receive a free programmable thermostat and a one-time incentive payment of $25 for residential customers per unique address, and $50 for small commercial customers per unique building.
Small Business Direct Load Control (Small Business DLC)		
Commercial System Relief Program (CSRP)	Event activated when day-ahead forecast is 96% or greater than the summer system peak forecast to relieve system peak load. Premium paid for customers who pre-commit load.	Customers receive a reservation payment of $5/kW pledged and performed. Performance payment equal to $.50 per kWh for each kWh reduced during an event. Customers who do not pre-commit load receive an energy payment equal to $1.50 for each kWh reduced.
Residential Smart Appliance Program (CoolNYC)	Event activated when day-ahead forecast is 96% or greater of forecasted summer system peak to relieve system peak load. Con Edison has the ability to control window or wall A/Cs when an event is called. Available to Con Edison residential customers with window or wall A/C units.	Participants receive a free smart modern outlet (modlet), remote thermostat and gateway device allowing control via a web portal and smart phones. Participation in event hours results in an annual incentive payment of $25.

2.3 Report Organization

The remainder of this report is organized as follows. Section 3 provides a conceptual overview of the cost-effectiveness framework and model, including a summary of the different perspectives from which programs are analyzed. The report also discusses some of the unique challenges of cost-effectiveness analysis for DR programs and the valuation of benefits for distribution systems, provides an overview of the main benefits and costs associated with DR and discusses the issue of overlapping programs. Section 4 provides details about how the diversity of CECONY distribution networks is factored into the cost-effectiveness framework and model. Section 5 presents results from the application of the model to CECONY's DR programs that target large commercial and industrial businesses and includes key findings and sensitivity analysis. Section 6 presents results for CECONY's mass market DR programs for residential and small business customers while Section 7 discusses the CoolNYC pilot program. Section 8 provides key conclusions and recommendations. The report also includes several relevant appendices that provide more detail.

3 Conceptual Overview

Cost-effectiveness analysis is a widely applied tool designed to allow for direct comparison across resource options and to provide a basis for prioritizing investments. The main goal is to facilitate more efficient allocation of resources by using a common metric – net benefits or the benefit-cost ratio – to assess alternative options. Cost-effectiveness analysis is generally applied on a forward looking basis to investments that typically have large upfront costs but have benefits that accrue over multiple years. It also requires a pre-specified perspective (e.g., societal, utility, etc.), since two different parties can view the same outcome differently.

This chapter provides an overview of the model and data that underlie the cost-effectiveness estimates presented in this report. While considerable work has been done elsewhere to develop cost benefit frameworks, there are a number of issues that either have not been addressed or fully resolved when applying cost-effectiveness analysis to an assessment of DR programs that are designed to provide distribution system relief in highly reinforced networks.

This section is divided into six subsections. First, some of the fundamental concepts for cost-effectiveness of DR programs are discussed. Next, we address the issue of how the perspective taken determines the benefits and costs that are included in the cost-effectiveness calculations. The next three sections provide an overview of the key benefit-cost calculations and the key benefits and costs that are incorporated into the analysis. Finally, overlap issues that arise between programs and between CECONY and NYISO and between DR and energy efficiency are discussed.

3.1 Fundamental Concepts for DR Cost-effectiveness

The term *demand response* is used to describe programs and rates that are designed to shift or reduce loads during specific hours in a dynamic fashion. It includes a wide array of programs that have different characteristics. Some DR programs contract for specific amounts of load reduction and specify when the resource must be available, how many total dispatch hours can be exercised, the lead time for event notification and payments and penalties tied to performance. Other DR programs, such as air conditioner direct load control, rely on technology to reduce demand with no notification or performance-based payments or penalties. These technology based programs can often deliver large demand reductions very quickly. Still other DR programs, such as dynamic pricing, are purely behavioral and do not rely on either a performance contract or enabling technology. For many DR programs, such as DLC and residential dynamic pricing, the resources available vary substantially with weather and hour of the day and, conveniently, tend to offer greater DR potential when demand reductions have their highest value (e.g., hot days when air conditioning loads are high and the distribution and supply systems are constrained).

The need for a demand response specific cost-effectiveness framework has been widely recognized and several efforts to develop such a framework have been undertaken in the past decade. These are summarized in Appendix A, which includes a literature review of DR specific cost-effectiveness frameworks. Most cost-effectiveness frameworks focus on classifying benefits and costs differently depending on the perspective taken. Currently, there is little debate about the key benefit and cost categories. The debate is more about how to properly quantify benefits and about when they apply.[7]

Prior to detailing benefits, costs and the model components, it is important to first understand two fundamental concepts that affect DR valuation, namely:

- Peak demands drive a large share of generation, transmission and distribution capital investments; and
- The value of demand response depends on the specific characteristics of the resource.

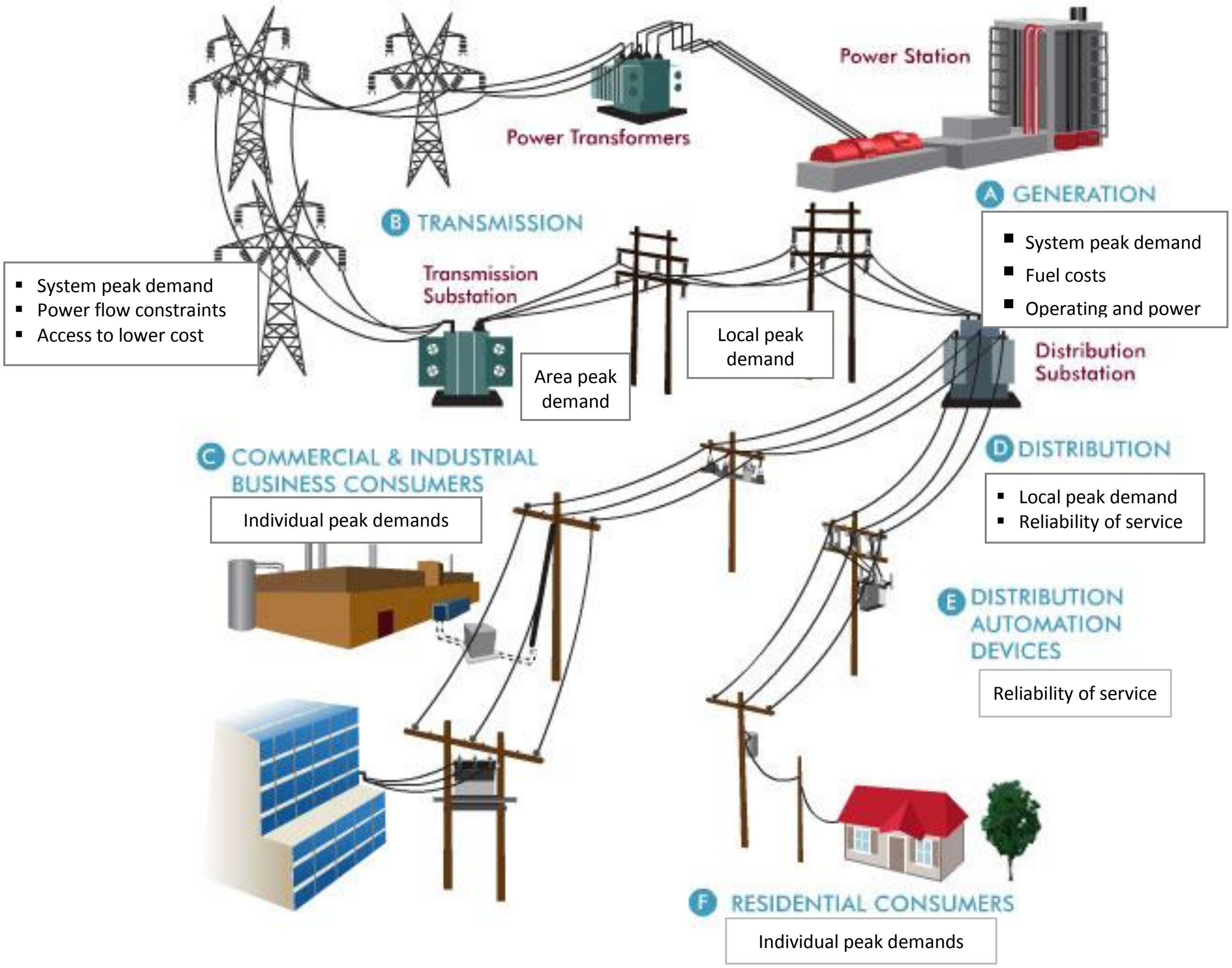
For most utilities, roughly half of a customers' bill is related to power production costs and half is tied to recovery for transmission and distribution investments that allow power to flow from where it is produced to end consumers. For CECONY, almost one third of the average customer's bill goes to taxes. The remaining two thirds is split roughly 50/50 between generation and T&D costs.

Figure 3-1 illustrates the key components of the grid and the main drivers of investments at each level. What is striking is that most investments are driven by peak demands for different parts of the system as detailed in the boxes found throughout the figure. Enough generation and transmission is built to meet extreme levels of electricity demand that occur in rare instances – e.g., 1 day out of every 10 years – but are typically not needed for normal day-to-day operations. At the distribution level, a substantial share of investment is also driven by local, coincident demands that are shared across many customers. The timing of local peaks varies from network to network, with some peaking during the day and other networks peaking at night. When aggregate peak demand exceeds the capacity of specific components, such as distribution lines, they overheat and the risk of cascading failures grows exponentially. As a result, most distribution systems also have a substantial amount of capacity that is only required for peaking conditions. It is important to keep in mind that not all distribution investments are driven by peak demand. Some distribution investments are required to improve reliability by redesigning or automating distribution systems and some investments are driven by a customer's individual peak.

While a large portion of the generation, transmission and distribution capacity at different levels of an electric system is not used or needed very often, it helps ensure that the power grid can be operated reliably – that is, it provides a form of insurance. A unique feature of insurance is that it provides value even if it is not used each year. For example, most home and auto owners pay for insurance each year, but do not file an insurance claim each year. Likewise, no one knows in advance if extreme or normal peaking conditions will occur in a given year, yet it is still necessary to have sufficient resources in place to meet local and system electricity peaks under an array of potential conditions.

[7] Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013). NAPDR Cost Effectiveness Framework. National Action Plan on DR. page 35.

Figure 3-1: Electricity Components and Drivers of Investment



The value of demand response depends on the specific characteristics of the resource and on how well they line up with system peaks, local peaks, or both:

- *Availability* – When is the resource available? How well does availability align with when peak demands are likely to occur?
- *Exhaustibility* – How many total hours can a resource be dispatched?
- *Magnitude and timing of reductions* – How well does the magnitude of demand reductions align with local and system peak demands?
- *Maximum event duration* – How long can demand reductions be sustained? How does this align with the duration of peak loads?
- *Predictability* – Do reductions vary with weather or time of day? Are the reductions predictable or is there substantial unexplainable variation?
- *Speed* – How quickly does a resource respond? How much advance notice is needed by customers and operators?

The availability of DR resources is one of the most critical factors in valuation. If a resource is not available when it is needed, it has less value than a resource that is available. Sometimes DR availability is confused with exhaustibility. Availability refers to the number of hours a resource is available to operators, regardless of whether it is utilized. Exhaustibility refers to the likelihood that a resource is exhausted too early and thus unavailable when needed. For example, a program that can be activated on weekdays between 12–8 PM during the months of May through October is on-call for roughly 1,000 hours. Those 1,000 hours may cover most of the periods when local and/or system peak demand is likely to occur. However, if the program is limited to a maximum of 100 hours for the summer, this limitation must be factored into the analysis. Because DR resources are designed for extreme peaking conditions or emergencies, they do not need to be activated often and may not be needed at all in some years. However, a resource that can be dispatched for more hours in a given year provides more flexibility – operators do not have to worry about potentially exhausting a resource prematurely.

Resources that can be dispatched for longer periods of time are typically more valuable. A program that has a maximum event duration capped at four hours for a day may reduce the risk of resource shortages for most key hours but will not be available on several high risk hours that fall outside of the event window. In practice, the hours that are near the peak are often as much of a concern as the peak load itself. A resource that can be dispatched for up to six hours inherently has more value, all other things equal, than one that can only be dispatched for four hours. This doesn't mean the resource needs to be dispatched six hours each time it is activated, but the option of being able to do so is highly valuable. Some load areas have short peak periods while other areas have prolonged peaks. The extent to which the maximum event duration affects value depends, in part, on the load shape during peaking conditions.

The speed of response can also affect valuation by allowing DR to access additional benefit streams. Resources that can respond quickly can be useful for balancing loads, or in helping maintain grid stability when system shocks such as near-instantaneous generation and transmission outages occur. Some amount of flexible resources is essential to grid operations and system operators have set up markets – typically, referred to as ancillary service markets – to procure these services. At all times, operators maintain a certain level of reserves to balance the grid and maintain the ability to respond to system shocks. Some DR resources can deliver fast load response. Prior studies have shown that air conditioning load control can be used for grid operations, typically starting up within 60 seconds and ramping up to 80% of capacity within 3 minutes.[8,9] While fast response is required for some grid operations, it is important not to mistake generation, transmission and distribution capacity – that is, the ability to meet peak demands – with operational flexibility. Capacity related events are rarely instantaneous.

The magnitude of demand reduction also plays a role in valuation, particularly when it comes to deferring capacity investments. However, the magnitude of all demand side resources determines

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[8] Sullivan, Bode, Kellow and Woehleke (2013). *Using Residential AC Load Control in Grid Operations: PG&E's Ancillary Service Pilot.* IEEE Smart Grid Transactions. Volume 99. pp. 1-9.

[9] Bode, Sullivan, Berghman and Eto (2013). *Incorporating Residential AC Load Control into Ancillary Service Markets: Measurement and Settlement.* Energy Policy. *Volume 56, May 2013, pp. 175–185.*

the overall deferral period more so than any single program. The magnitude of demand reductions interacts with the time scale for planning. Small reductions, e.g., less than 1%, can technically defer investments for very short periods but have little economic value because the deferral period is so short that the time-value of money associated with the deferral is quite small. Larger DR programs and portfolios can be used to defer investments for a longer period of time, thus generating more economic value.

3.2 Cost-effectiveness Perspectives

Typically, cost-effectiveness analysis focuses on whether or not specific policies or programs lead to overall improvements in welfare – whether benefits outweigh costs. When benefits outweigh costs, all relevant stakeholders could be made better off through appropriate redistribution. However, policies and programs often produce winners and losers. What counts as a benefit and as a cost often depends on the perspective adopted. For example, lower prices are typically favorable from a consumer's perspective but can mean reduced profit margins from a producer's perspective. A widely accepted industry practice is to assess energy efficiency and demand response programs from multiple perspectives. Depending on the perspective adopted, certain benefits do or do not accrue and costs under one perspective can be viewed as transfers from another perspective. Table 3-1 summarizes these different perspectives.

The most commonly used test for screening the value of DR programs is the Total Resource Cost (TRC) test, but in some instances the Utility Cost Test (UCT) is used instead.[10] The TRC test includes the full incremental cost of the resource and focuses on the most tangible costs and benefits. It also assesses whether utility customers, in aggregate, are better off with the program.

[10] CECONY historically has used the UCT test for DLRP. This was partly because the primary cost of the program is incentive payments to participants, which are treated as transfers under the TRC test. The prior cost-effectiveness model did not incorporate cost associated with delivering demand reductions since these costs are typically not directly observable (e.g., opportunity cost of production, comfort, etc.). The updated cost-effectiveness framework assumes that the cost of delivering demand reductions is 75% of customer incentive payments.

Table 3-1: Summary of Cost-effectiveness Perspectives

Perspective	Key Question Answered	Description
Societal	Will total costs to society decrease?	Includes all costs and benefits to society, including those that are not captured in market prices such as reductions in environmental externalities or reductions in outage costs due to improvements in reliability. This test views incentive payments as transfers from non-participants to participants and, as such, incentive costs are excluded. However, customers may also incur costs (e.g., equipment costs, reductions in welfare, etc.) in order to reduce demand. It is typically assumed that these costs are less than the incentives customers receive from participation.
Total Resource	Are utility customers better off overall?	This test includes the same costs and benefits as the societal test except for externalities and outage costs. It is meant to represent the full incremental cost of the resource, including costs borne by the utility, third party providers and program participants.
Utility	Do costs for the utility decrease?	Includes the costs and benefits that are experienced by the utility. This test is useful for identifying impacts on utility revenue requirements and provides information on the effectiveness of program delivery.
Ratepayer Impact	Do ratepayer electricity bills decrease?	Useful for understanding whether utility rates need to increase to fund the program. It is the perspective of all utility customers who do not participate in programs. Under this paradigm, incentive payments to participants are treated as a cost since the utility needs to collect the revenue.
Participant	How much does a participant benefit from participation?	Useful for understanding how attractive a program is from a participating customer's standpoint. This is difficult to quantify for DR since many of the opportunity costs associated with reducing demand cannot be directly observed.

3.3 Conceptual Overview of Model Calculations

Network characteristics directly affect value and the degree to which DR can be used to manage peaks. Therefore, it is critical to avoid assuming that all distribution areas are alike and to develop a model with sufficient granularity to reflect key differences. The cost-effectiveness model inputs and calculations were designed around eight distinct CECONY network types. Section 4 discusses how these groups were developed and the rationale behind them. The decision to group networks and load areas into similar categories was made because developing inputs and calculations for each of CECONY's 83 distribution load areas would have made the model too complex and limited its flexibility.

For each network type, model users have the ability to include network specific inputs, including: enrollment and growth strategies; demand reduction performance; avoided generation, transmission and distribution costs; and cost inputs. In other words, the inputs can be customized to reflect key differences between networks that materially affect cost-effectiveness. For example, CECONY currently pays higher reservation or option payments to DLRP participants that enroll in Tier 2 networks.[11]

For each program, the benefits and costs are calculated for each network type. These values are subsequently aggregated and overhead costs are added to produce cost-effectiveness results for each program. Some programs such as DRLP and CRSP have multiple options – mandatory versus voluntary – that provide different payment structures and amounts. In those instances, each option is assessed separately and the benefits and costs of the different program options are aggregated to produce an overall program cost-effectiveness estimate.

Conceptually, the model calculations are straightforward, although the mechanics can be complex. Figure 3-2 provides an overview of the benefit calculations. Appendix C provides a more detailed overview of the model architecture and mechanics. The benefit calculations are conducted separately for each benefit, network type and year. As discussed in more detail below, the calculations differ slightly for programs that require a pledged demand reduction and those that do not and for benefits associated with energy savings (kWh) rather than demand reductions (kW). The differences are discussed further below. Nearly all major benefits are tied to reductions in consumption (energy savings) or reductions in demand. Energy savings refers to reductions in consumption (kWh) during both event and non-event days that can be attributed to the DR program. Benefits from energy savings are not to be confused with performance payments, which are quite distinct.[12]

There are a few benefit streams, such as ancillary service benefits, that require small additional adjustments to account for decisions about bidding strategy into ancillary service markets. The model also accommodates other, user specified benefit streams tied to the number of participants or benefits that are fixed. For simplicity, the figure illustrates the calculations for the core benefits.

For programs such as DRLP and CSRP, pledged reductions, not the number of participants, are used as the basis for estimating benefits and costs for two main reasons: payments are based on the pledged reductions and the amount of pledged reductions often matters more than the number of enrolled customers. For these programs, the benefit stream is multiplied by the amount of enrolled pledged reductions (enrolled MW). It is then multiplied by the historical performance to account for differences between the pledged and delivered reductions. Finally, the model takes into account the coincidence of the demand reduction with the localized peak conditions. This is done by hour and month. Avoided generation capacity costs are based on the NYISO system peaks, but are only counted for participants not enrolled in NYISO programs. CECONY DR programs provide benefit to the NYISO system when CECONY DR program dispatch coincides with NYISO peaking conditions. For distribution capacity costs, the coincidence between the demand reductions and peaking conditions for the network group is calculated.

[11] Tier 2 networks are defined in Section 4.

[12] Performance payments are not payments for energy savings. They are simply a means for rewarding customers for how well they comply with pledged reduction on an event by event basis and are based on capacity value.

Figure 3-2: Conceptual Illustration of Benefit Calculations

Programs	Benefits Tied to…	Basic Calculation
DLRP and CSRP	Peak Reductions (kW)	Benefits tied to peak demand reductions ($/kW-year) × Pledged demand reductions enrolled (kW) × Reductions as measured by the historical performance by hour and month (%) × Coincidence with the risk of peaking conditions by hour and month (%) = TOTAL BENEFITS PER YEAR ($)
DLRP and CSRP	Energy Savings(kWh)	Benefits tied to energy savings ($/kWh) × Pledged demand reductions enrolled (kW) × Reductions as measured by the historical performance by hour and month (%) × Total hours on expected dispatch days (#) × Coincidence with energy market prices ($/kWh) = TOTAL BENEFITS PER YEAR ($)
Residential DLC, Small Business DLC, and CoolNYC	Peak Reductions (kW)	Benefits tied to peak demand reductions ($/kW-year) × Devices (#) × Reductions per device by hour and month (kW) × Coincidence with the risk of peaking conditions by hour and month (%) = TOTAL BENEFITS PER YEAR ($)
Residential DLC, Small Business DLC, and CoolNYC	Energy Savings(kWh)	Benefits tied to energy savings ($/kWh) × Devices (#) × Reductions per device by hour and month (kW) × Total hours on expected dispatch days (#) × Coincidence with energy market prices ($/kWh) = TOTAL BENEFITS PER YEAR ($)

Benefits associated with energy savings are similarly structured, except that the model factors in the number of events called and how well energy savings and increases (if load shifting occurs) coincide with wholesale energy prices. The model can also factor in non-event day energy savings, provided reliable estimates of reductions by hour and month during average weekday conditions are available. Certain DR resources either deliver non-event energy savings or have the potential to do so. For example, both the DLC and CoolNYC technology allow program participants to remotely program or modify thermostat settings and provide feedback about air conditioner energy use. This can potentially lead to changes in behavior that impact energy use at other times.

When accounting for the coincidence between peaking conditions and demand reductions, the model factors in specific DR characteristics such as the availability across hours and months, any limits on how long reductions can be sustained and the spillover of reductions or load shifting to hours before and after the event period. The net result of this adjustment is a de-ration factor. DR resources that deliver more reductions or perform better when they are most needed are valued more highly; resources that have wider availability to respond are valued more than resources that have availability restrictions; and resources that can sustain reductions for longer durations are valued more highly than those that can only do so for shorter periods. Sections 4.2 and 4.3 explain these concepts in more detail.

3.4 Demand Response Benefits

Table 3-2 shows the main DR benefits that are typically included for each test perspective.[13] There are additional benefits to demand response that are agreed upon but are difficult to quantify or that are still subject to debate. The next section includes additional discussion regarding the first five benefits, which are common across all perspectives except for the participant viewpoint. We also discuss in more detail other potential DR benefits.

Table 3-2: Demand Response Benefits by Perspective

Benefit	Perspective				
	Societal	Total Resource	Utility	Ratepayer Impact	Participant
Avoided Generation Capacity Costs	☑	☑	☑	☑	
Avoided Transmission Capacity Costs	☑	☑	☑	☑	
Avoided Distribution Capacity Costs	☑	☑	☑	☑	
Avoided Energy Costs	☑	☑	☑	☑	
Ancillary Service Revenues	☑	☑	☑	☑	
Avoided Environmental Costs	☑				
Participant Bill Savings					☑
Financial Incentive to Participant					☑

13 NAPDR 2012 Cost-Effectiveness Framework.

3.4.1 Avoided Generation Capacity Costs

By reducing demand when the system peaks, DR has the ability to defer or delay the need for new generation capacity required to meet the extreme levels of electricity demand that occur infrequently. Most jurisdictions follow the North American Energy Reliability Council (NERC) guidance of having enough installed capacity to accommodate 1-in-10 year peak demands. In other words, sufficient generation capacity is installed to protect against extreme demand levels although it is not needed for normal day-to-day operations. In some cases, the capacity in place to meet extreme peaks can go unused for several years.

Avoided generation capacity cost is the benefit most commonly associated with DR programs. In organized markets such as New York's, this benefit is typically captured by bidding DR resources into capacity markets. However, resources that are not bid into the market, such as distribution level DR, can also lower capacity costs by lowering system peak demand. Lowering system peak demand lowers installed capacity requirements, which in turn lowers generation capacity costs. In addition, the cost of capacity auctions are allocated to utilities based on their contribution to the coincident system peak. As a result, decreasing demand lowers the share of capacity costs allocated to the utility and ultimately lowers costs to ratepayers.

Two key factors determine the extent to which avoided generation capacity costs apply to CECONY DR programs. The first is whether or not customers otherwise participate in NYISO DR programs that provide compensation for generation capacity. If those resources are already contracted into the market, they cannot be claimed by CECONY without double-counting benefits. Two programs in particular, DLRP and CSRP, have substantial overlap with capacity procured by NYSIO. CECONY has analyzed NYISO participation to understand the share of pledged demand reductions that overlap. This helps coordinate operations targeted at reducing system or network peaks. It also helps avoid double-counting of avoided generation capacity costs. As of 2012, 70% of the pledged demand reduction enrolled in DLRP and CSRP were also enrolled in NYISO programs. As a result, only 30% of the reductions in these programs can lead to reduced generation capacity costs, provided they target hours when the NYISO system peaks.

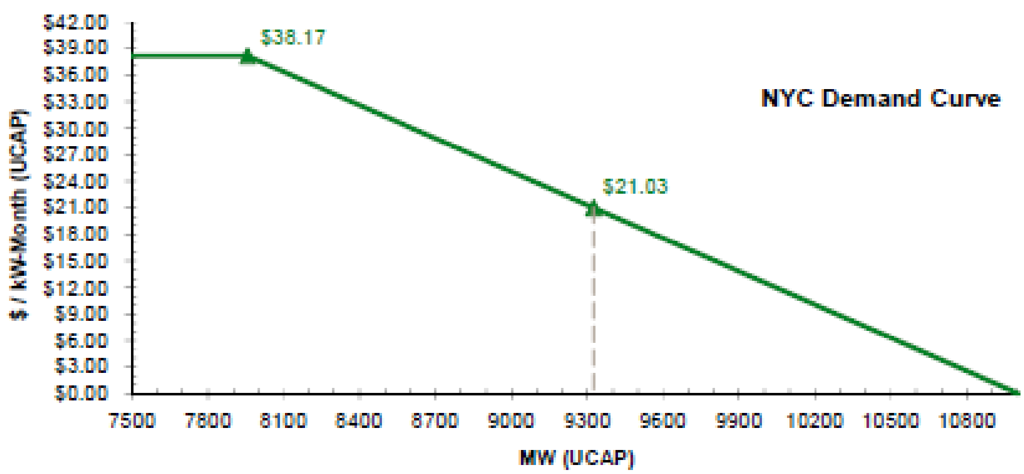
The second key factor that affects the extent of avoided generation costs that can be attributed to CECONY programs is the degree to which event dispatch coincides with NYISO system peaks. Individual network peaks do not necessarily coincide with NYISO peaks. They can peak in days and hours that differ from the NYISO peak. As discussed earlier, the avoided generation capacity benefits are adjusted to factor in the extent to which they coincide with NYISO system peaks. A program that is more likely to reduce demand when the NYISO system is peaking helps avoid generation capacity costs more so than a program that is less likely to be activated at the right time. This downward adjustment was calculated based on the degree to which CECONY events for each program overlapped with the top five NYISO peak demand days in 2010-2012. It ranges from 25% to 40%, depending on the program, and reflects CECONY's current practice of dispatching DR resources based on network peaking or emergency conditions.

The amount of avoided generation capacity value attributed to CECONY programs is a function of the two aforementioned factors: the share of resources that is not contracted into the market and the degree to which CECONY event dispatch coincides with NYISO events. For example, 70% of the approximately 180 MW enrolled in DRLP in 2012 were already contracted into the NYISO capacity market. The remaining 30% of resources (54 MW) could be used to lower generation capacity costs, but historically CECONY has dispatched its resources during 27% of NYISO events. As a result, avoided capacity generation benefits are only counted for 9% of resources (30% x 27%) or 14.5 MW. This value is further adjusted downward based on the resource's availability, maximum event duration and coincidence with NYISO peaking conditions, as explained in Section 4.3.

The avoided generation capacity costs used for cost-effectiveness were based on NYISO's 2013 summer auction, which provides capacity payments for the six months when CECONY's programs are active. The capacity auction results can vary from year-to-year based on the degree to which installed capacity exceeds or falls short of installed capacity requirements. Over the long run, the auction is designed to migrate toward the cost of new entry, an estimate of the capacity payments needed to encourage new peaking generation.

Figure 3-3 shows the NYISO capacity market's demand curve for the New York City zone, where the majority of CECONY's DR resources are located.[14] In 2013, the target price for generation capacity was $21.03 per kW-month for the six summer months ($126.18 per kW total for summer period). The prices resulting from the auction were lower, $15.08 per kW-month ($90.48 per kW total for summer period), indicating that current installed capacity exceeds the target level.[15] For future years, we assumed that capacity prices will trend toward the equilibrium price, $127.18 per kW per summer, over a five-year period. The estimates also incorporate a 2.1% annual inflation factor. Table 3-3 presents the avoided generation capacity costs used in the cost-effectiveness model for the first 10 years. The same avoided generation capacity costs were used for all eight network types.

Figure 3-3: New York City Zone 2013 Capacity Market Demand Curve



14 The capacity demand curve documentation includes information about cost of new entry, target installed capacity, and other determinants of the demand curve. It is available at: http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2013/Summer_2013/Documents/Demand_Curve_Summer_2013_Revised.pdf

15 Summer 2013 capacity auction results are available at: icap.nyiso.com/ucap/public/auc_view_monthly_detail.do

Table 3-3: Avoided Generation Capacity Costs

Year	Generation Capacity ($kW-year)
2013	$90.50
2014	$100.23
2015	$109.96
2016	$119.69
2017	$129.42
2018	$132.14
2019	$134.92
2020	$137.75
2021	$140.64
2022	$143.60

[1] Values are in nominal dollars - that is, they include 2.1% inflation per year

3.4.2 Avoided Transmission and Distribution Capacity Costs

Transmission and distribution investments are typically driven by the need for capacity. Existing cost-effectiveness frameworks recognize three potential sources of benefits from reducing load growth and/or delivering load relief:

- Avoid or delay capacity upgrades (capital costs) and associated operation and maintenance costs;
- Reduce equipment degradation and the frequency of maintenance by reducing the amount of time components can carry loads at or near design capacity; and
- Improve reliability when upgrades are delayed.

These values are related. Decisions about when to upgrade transmission or distribution components are often tied to the expected frequency that specific components will need to carry loads above their design capacity. Adding capacity will typically improve reliability.

For the transmission system, not having adequate capacity in place to support local peak demands not only leads to inefficiencies but also complicates power flow and increases the risk of overheated transmission lines, line losses and loss of load probability. While generally coincident with the need for generation capacity, the peaks used for transmission planning are sometimes more localized and do not necessarily coincide with the overall system peak. Transmission upgrades often require prolonged stakeholder efforts and, as a consequence, have very long lead times. The exact timing of when transmission upgrades can occur is sometimes uncertain.

In order to offset transmission investments, load reductions must occur at the right location and at the right time. Absent additional transmission capacity, when a transmission constrained load area is peaking, operators must actively balance the system to relieve congestion and facilitate power flow. This can be accomplished in one of two ways. The first option is to increase generation, if it is available within the load pocket. Increasing generation outside of the load pocket could in fact exacerbate congestion. The alternative is to reduce demand within the load pocket. Reductions must be precise because transmission operators sometimes need to manage multiple load pockets at once. With generation, this means ramping different generators at different locations to the precise levels needed to relieve the congestion. Overshooting generation production in one load pocket can have unintended consequences for transmission congestion in neighboring load pockets. If transmission congestion is to be relieved through reducing loads, rather than by increasing transmission capacity, the reductions must also be precise to enable operators to manage the power flow.

The magnitude of avoided distribution investment costs varies with the design of the distribution system, location, trends in customer load growth, load patterns, the amount of excess distribution capacity, equipment characteristics (e.g., failure rates) and uncertainty in growth forecasts. In general, the requirements to avoid distribution investment costs are different in radial distribution systems than they are for distribution networks, which are more interconnected. A discussion on deferring investments in radial distribution systems can be found at the end of this subsection.

As discussed earlier, most of CECONY's electric customers are served through low voltage, underground networks. With CECONY's networks, there are multiple paths through which power can flow to customers. Each network is designed to operate independently of every other network. As a result of this design, a problem in one network cannot affect customers in another network. CECONY distribution networks typically include between 6 and 29 interconnected feeders that are linked to an area substation. They are designed to continue operating uninterrupted even if the two main components, typically feeders, fail during peaking conditions.

Figure 3-4 depicts a simplified illustration of CECONY's distribution networks. The illustrated network has eight feeders and is far less interconnected than most of CECONY's networks. The networks have several components whose investments are driven by coincident peak demand. It is the interconnected nature of CECONY's distribution system that provides opportunities for load relief to lower distribution system costs. A reduction by one customer lowers the amount of capacity used by that customer so the capacity can be used to either relieve overloading or to accommodate future growth.

Each network has several components for which investments are driven by shared coincident peaks. These include the area substation, feeders, transformers that step down power for the secondary distribution system and multiple sets of low-voltage cables installed in ducts under the streets. The network provides multiple paths for power to flow to each individual customer. If a cable in the secondary system goes out of service, a customer can be supplied by another cable. Likewise, if a feeder line goes out of service, customers' loads can be switched onto another feeder. Non-network areas are not as highly interconnected. There are typically multiple alternatives to supply power to the secondary distribution system should a feeder go out of service, but there are not necessarily multiple pathways to deliver power to customers if a secondary voltage cable goes out of service.

The majority of investments in each network component depicted below are driven by peak load growth. Some investments are driven by aging equipment or are designed to improve reliability by improving the automation of load switching and component restoration.

Figure 3-4: Illustration of CECONY's Distribution Networks

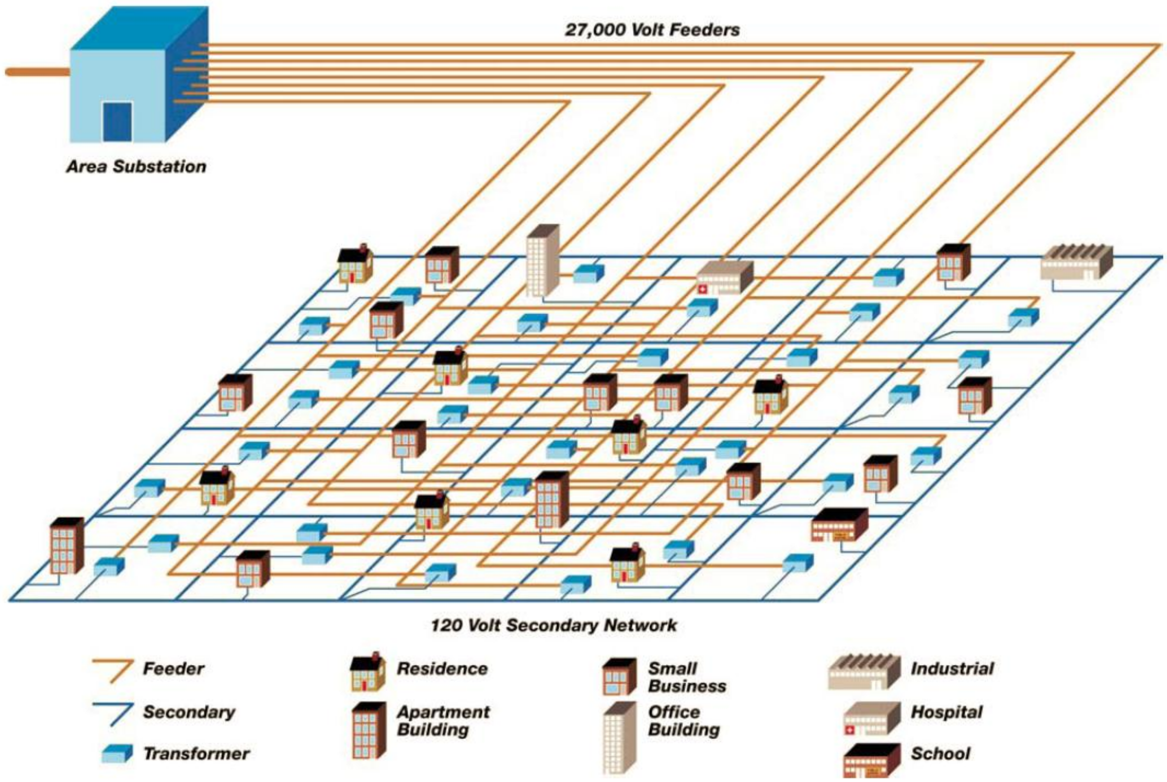
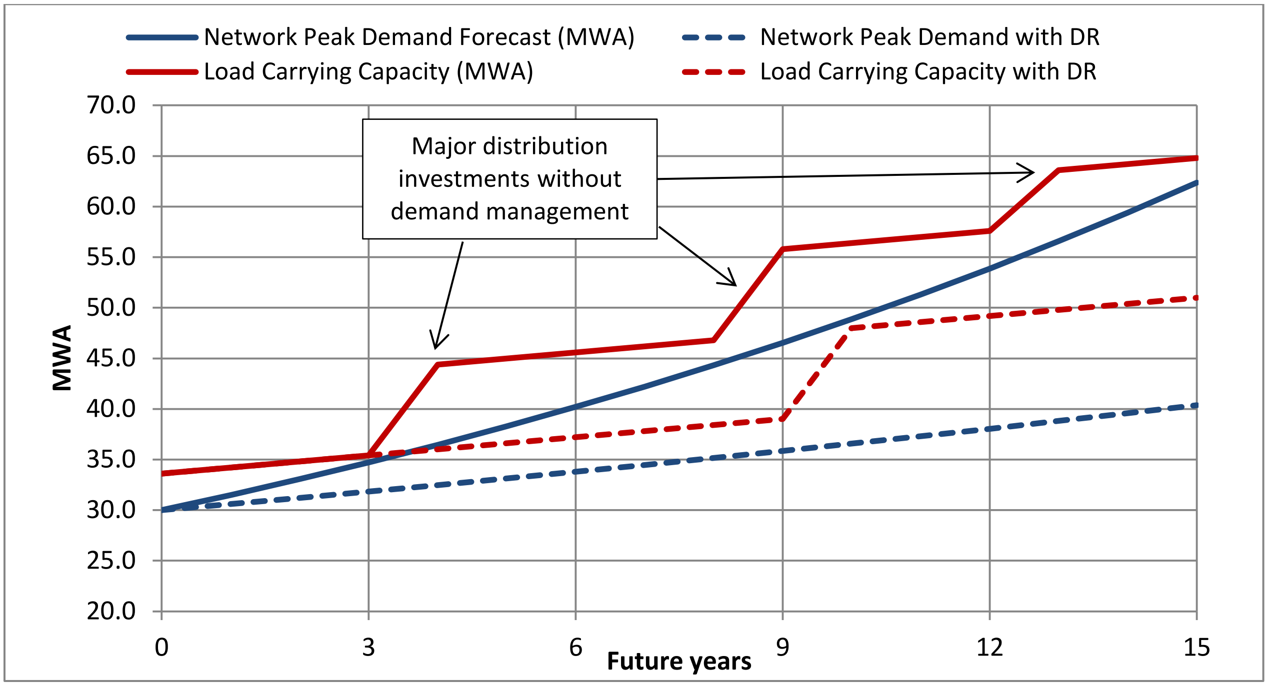


Figure 3-5 illustrates the effect of reducing peak demand on distribution investments. Distribution investments are characterized by smaller investments that occur annually and major investments that occur less frequently. When distribution components are upgraded, it is often more economical to install excess capacity to accommodate future additional load growth. As a result, the load carrying capacity of a network can change substantially with major investments. Lowering peak demands can avoid or delay distribution upgrades. Load reductions can also improve reliability and reduce equipment degradation by reducing the amount of time distribution components carry loads at or near design capacity. The benefits of avoiding distribution investments are quantified by calculating the present value of distribution investments with and without demand management.

Figure 3-5: Illustrative Effect of Reducing Peak Demand on Distribution Investments



CECONY commissioned a detailed assessment of transmission and distribution costs associated with load growth that was completed in 2012.[16] The study excluded transmission and distribution components that were not driven by a network's coincident peak. It also excluded transmission congestion charges, which are reflected in the NYISO market. Estimates were developed for each of the main transmission and distribution components and annualized to provide an estimate of savings per kW-year. The cost-effectiveness analysis relies on the avoided cost estimates from the 2012 study.

Table 3-4 summarizes the avoided transmission and distribution costs used in the cost-effectiveness analysis. The last two columns show the avoided cost estimates. The distinction between network and non-network avoided costs is discussed in more detail immediately after Table 3-4. The avoided costs for networked areas were applied to six of the eight network groups. The non-network avoided costs were applied to the two remaining groups, which consist of distribution areas with radial designs. In practice, the model can accommodate different avoided cost estimates, by year, for each of the eight network types if avoided cost input values are available at a more granular level in the future.

[16] NERA Consulting. (2012). Consolidated Edison Company of New York, Inc. Marginal Cost of Electric Distribution Service. Prepared for CECONY.

Table 3-4: Avoided Transmission and Distribution Costs

Year	Transmission Costs Excluding TCCs ($ per kW)	Switching Station Costs Transmission Functionality ($ per kW)	Switching Station Costs Substation Functionality ($ per kW)	Area Station and Sub-transmission Costs ($ per kW)	System Weighted Primary Feeder Costs ($ per kW)	System Weighted Transformer Costs ($ per kW)	System Weighted Secondary Cable Costs ($ per kW)	Network T&D Avoided Costs ($ per kW)	Non-network T&D Avoided Costs ($ per kW)
2013	0.00	0.00	0.00	13.86	28.77	40.77	37.12	**120.52**	**42.63**
2014	0.00	0.00	0.00	6.97	29.63	41.99	38.24	**116.82**	**36.60**
2015	0.00	0.00	0.00	43.88	30.52	43.25	39.38	**157.03**	**74.39**
2016	0.00	0.00	0.00	82.90	31.43	44.55	40.57	**199.45**	**114.34**
2017	4.31	0.00	0.00	49.68	32.38	45.88	41.78	**174.04**	**86.37**
2018	17.10	1.49	1.36	127.30	33.35	47.26	43.04	**270.90**	**180.61**
2019	4.62	4.62	4.20	119.43	34.35	48.68	44.33	**260.22**	**167.21**
2020	31.86	1.58	1.44	144.87	35.38	50.14	45.66	**310.93**	**215.14**
2021	32.99	8.16	7.42	126.51	36.44	51.64	47.03	**310.19**	**211.52**
2022	34.04	14.85	11.18	181.57	37.53	53.19	48.44	**380.81**	**279.18**

3.4.3 Avoided Energy Costs

Energy savings refers to the net change in energy (kWh) during both event and non-event days that can be attributed to the DR program. Societal avoided energy costs are typically a small component of DR resource benefits because curtailment events only take place due to peaking conditions or emergencies.[17] Simply put, event-day curtailment hours are typically too few (<1% of annual hours) to produce substantial energy savings. The model accommodates both event-day and non-event day energy savings by hour and month.

Nevertheless, some DR resources have delivered energy savings outside of curtailment periods. For example, time-of-use and real time pricing are often paired with dispatchable technology and have been shown to lower peak demands on non-event days (as participants program thermostats to use less peak period energy use on all weekdays when prices are high, for example). CECONY's DLC program and CoolNYC pilot have the potential to deliver non-event day energy savings. These programs provide customers with technology that allows them to remotely program or modify thermostat settings and to receive feedback about air conditioner energy use. These additional capabilities can potentially lead to changes in behavior that produces energy savings or, possibly (though less likely), increases in energy use. If substantial enough, reductions in energy consumption can also reduce the DR potential as there is less demand to reduce dynamically.

In estimating energy savings, the cost-effectiveness analysis factors in both reductions during event periods and any increases in consumption outside the event period. Increases can arise due to behavioral load shifting or, more commonly, because direct control of end-use equipment can lead to snap back effects after control is released and the air conditioning unit works to reduce the temperature to the set point. The analysis factors in the extent to which increases and decreases coincide with wholesale electricity prices during average weekdays to calculate societal non-event savings, and with monthly peak days to calculate event-day savings.

The wholesale electricity prices used in the model are based on NYISO 2010-2012 day-ahead market prices for the New York City zone. We estimated hourly load profiles, by month, for peak days and for the average weekday. Peak day prices are based on dates when CECONY's system load peaked in the 2010 – 2012 period.[18] These may not be the highest prices experienced in the market but they are the most applicable for DR events that are called when the CECONY system is peaking or due to emergencies on specific distribution networks (due to feeder outages). Average weekday prices were estimated based on the average prices, by hour, for weekdays for each month a program is in effect. Multiple years were used for the analysis to minimize idiosyncrasies that can occur for individual years either due to weather or volatility in natural gas prices.[19] The prices for each year were normalized by

[17] Energy savings are related but distinct for performance payments. Energy savings refers to reductions in consumption (kWh) during both event and non-event days that can be attributed to the DR program. Both reductions and increases in consumption are included in the energy savings calculations. Performance payments are simply a means for rewarding customers for how well they comply with pledged reduction on an event by event basis.

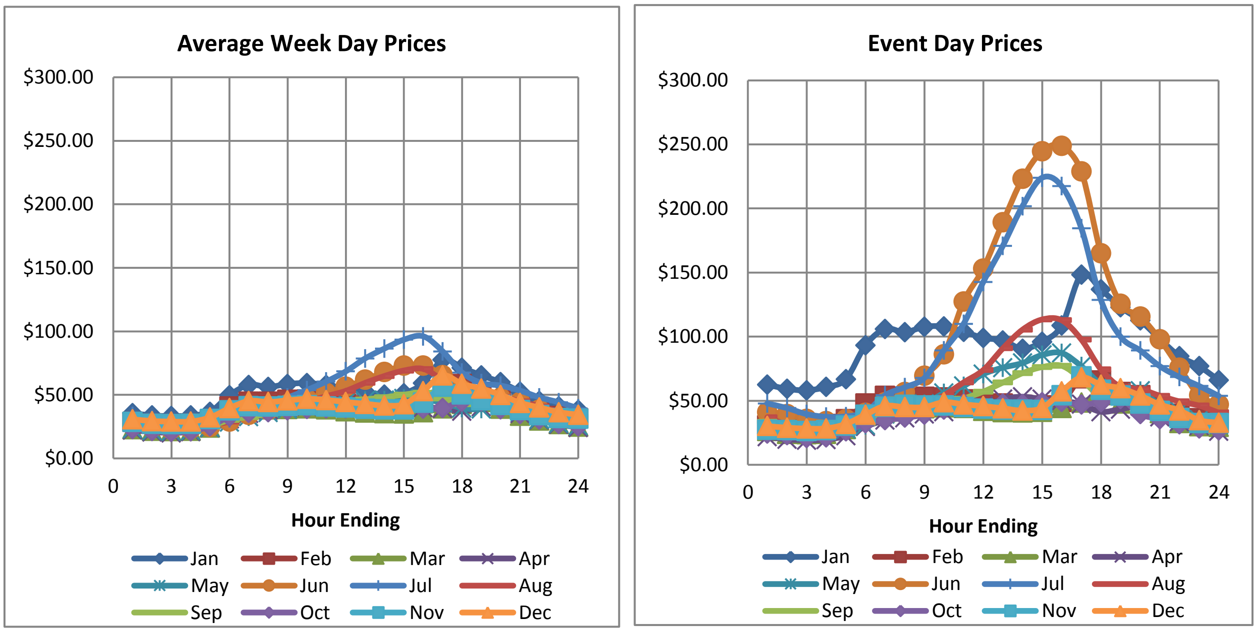
[18] Wholesale energy market prices and loads, by zone, are available at: http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp. The customer reports option allows user to download to select individual zones and download up to one year at a time.

[19] Natural gas typically fuel electric peaking generators which set the electricity market prices. As a result, year to year changes in natural gas prices affect electric market prices.

dividing prices in each hour in a given year by the average prices experienced each year. Next, normalized prices across all peak days and average weekdays were averaged. As a final step, wholesale market prices were rescaled by multiplying the normalized values by the average price in 2012, $39.28 per MWh.

Figure 3-6 summarizes the hourly prices, by month, used for event-days and non-event days. Appendix G includes tables with the underlying values. Not surprisingly, prices are highest in June and July.

Figure 3-6: Wholesale Energy Market Prices Used for Cost-effectiveness by Hour and Month



Two of the perspectives – the ratepayer impact and participant tests – also factor in distribution related energy charges. From a participant's perspective, reduced usage saves both energy production and delivery charges. From the perspective of ratepayers who are not participating in DR programs, the energy savings associated with demand management can result in higher rates per kWh since the same revenue to collect capital expenditures must be collected but from lower energy sales (due to reduced consumption).[20] The costs for delivery charges were based on CECONY's delivery charges contained in the May 2013 tariffs.[21]

[20] Of course, for cost-effective programs, this upward price pressure in the short run would be partially or fully offset over time by avoided G, T & D costs.

[21] CECONY's electric tariff book, which includes delivery charges, is available at: http://www.coned.com/documents/elecPSC10/SCs.pdf. Service classifications 1, 2 and 9 were used for residential, small business, and large customer programs, respectively. The charges used were, respectively, 8.9¢, 10.2¢, and 5.4¢. Large customer delivery charges include both volumetric, 2.4¢/kWh, and demand component. The demand charges vary depending on the size of the customer and whether or not they receive power through high or low tension lines. For 300 kW customers, those charges are $24 per kW for low tension service and $20 per kW for high tension service. For simplicity, demand charges where assumed to be $22 per kW and converted into an effective kWh rate by dividing the value by the number of hours when the peak demand could occur over the course of a month.

3.4.4 Avoided Ancillary Service Costs

Ancillary service costs are associated with maintaining the reliability of the electric grid. NYISO holds auctions for four primary ancillary services: regulation, 10-minute spinning reserves, 10-minute non-synchronized reserves and operating reserves.

Operators must have resources that are synchronized with the electric grid and that respond continuously over very short time scales (i.e., seconds or minutes) to balance system frequency and maintain power quality. These resources are typically referred to as regulation. They are designed to respond to small variations that occur moment-to-moment at all times.

The other ancillary service products are designed to maintain grid stability when system shocks such as near-instantaneous generation and transmission outages occur. They can broadly be referred to as contingency reserves. The defining characteristics of contingency reserves are fast start times and fast ramping capabilities. Because contingency reserves are used to back up the system, they are operated infrequently and, typically, for less than 10 minutes at a time.[22] They generally receive availability or option payments for providing fast response capability. Should a contingency such as a generator or transmission outage occur, a subset of these reserves are required to start injecting power into the grid (or, conversely, reducing load) within 2 minutes of notification and to ramp up to deliver the full resource within 10 minutes. These are referred to as spinning or synchronized reserves. These resources are synchronized to automatically respond to fluctuations in the grid that occur when the system becomes imbalanced. Additional supplemental reserves are also maintained on a stand-by basis that can be started and synchronized with the electric system with enough lead time, which can range from 10 to 30 minutes. They typically replace synchronized reserves when they are deployed in response to generator or transmission outages.

Ancillary service costs can be avoided if CECONY self-supplies such services or bids those services into ancillary service markets. Many DR resources have successfully demonstrated the capability to provide contingency reserves and several jurisdictions use demand response to provide a large share of contingency reserves. Half of the synchronized reserves in the Texas electricity market (2,300 MW) are delivered by DR resources. The California Independent System Operator (CAISO) also contracts for over 2,800 MW of DR from large water pumps as 10-minute non-synchronized reserves. Both of these resources have been in place for over a decade and have proven to be reliable for contingency operations. More recently, DR resources have been used to provide regulation services in PJM and several pilots and demonstrations are underway by various system operators to determine if load management can deliver regulation services reliably. In addition, several studies and demonstrations sponsored by the U.S. Department of Energy have shown that direct load control programs are able to deliver contingency reserves. These studies are further described in the literature review.

Despite the successful use of DR for contingency reserves in Texas and California, DR has not been used in the same manner in other jurisdictions mainly because rules were developed for generators,

[22] A 2009 review of the frequency and duration of contingency reserve operations by the California, New England, and New York Independent System Operators (ISO) found that deployments over 30 minutes were very rarely needed and that contingency reserves averaged roughly 10 minutes in each of the ISO's. Kueck K., B. Kirby, M. Ally, and Rice. (2009). *Using Air Conditioning Load Response for Spinning Reserve*. Oak Ridge National Laboratory. ORNL/TM-2008/227.

but preclude participation of DR resources, and have not been adjusted. The three primary barriers for utilizing DR for ancillary services have been: requirements for metering and telemetry for each end point; the inability to aggregate resources that are small individually but large in aggregate; and lack of clear settlement rules and processes and requirements that loads bid into both energy and ancillary service markets. [23]

The NYISO market rules have not been adjusted to allow disaggregate DR programs to supply ancillary services. The model currently allows the capability to quantify ancillary services based on the share of DR resources that are bid, the strike price and the ancillary service provided by the DR resource. However, no ancillary service benefits are claimed in the cost-effectiveness analysis presented here because they cannot be realized under current market rules.

3.4.5 Other Benefits

There are additional benefits and costs to demand response that are difficult to quantify.
These include:

- *Improved efficiency of wholesale markets*. DR is often cited as a means of improving the efficiency of wholesale markets, mostly by connecting retail customers to the time varying nature of electricity costs and mitigating the potential for market manipulation. However, there is little empirical data to quantify the degree to which DR resources help improve the efficiency of markets. There is also debate about whether DR programs that are scheduled as supply (versus time-varying rates) contribute to market efficiency.
- *Using DR modularity to gain more certainty about load growth forecasts.* Most distribution investments are driven by multi-year projections about load growth that typically have a wide degree of uncertainty. Load often grows faster or slower than projected. Demand response resources can typically ramp up or ramp down more quickly and at a more granular level than alternative infrastructure investments. Because of its modularity, DR can be used to ascertain with more certainty whether loads are following projected growth forecasts (after adding DR in).
- *Avoided outage costs due to increases in distributed generation*. Many customers utilize distributed generation – often from back-up generators – to deliver DR. While these resources help deliver DR, they also improve reliability for customers since they can continue to operate facilities or essential functions should an outage occur. Insofar as DR provides customers an incentive to invest in distributed generation above and beyond what they normally would do, it can enhance reliability for participants that adopt it.
- *Improved reliability to smooth out changes in reliability due to the lumpiness of distribution investments*. Many distribution investments lead to substantial changes in reliability. The current practice is to wait until the excess distribution capacity – the hedge room that provides reliability – is nearly exhausted. As a result, distribution networks can experience changes in reliability. With less excess capacity, the likelihood of component failure and an overall network outage increases. DR could be used to ensure that customers do not experience substantial changes in reliability. This is a different application than using DR as a substitute for reliability improvements. It requires strategically ramping up DR enrollment and ramping it down (by letting natural attrition take its course) to avoid substantial shifts in reliability.
- *Avoided disruption costs associated with transmission and distribution upgrades.* Because most of CECONY's distribution networks are underground, conducting major upgrades can require excavating the streets of New York City and can lead to disruption of businesses, traffic congestion and noise. In other words, the cost of distribution upgrades is not limited to

[23] J. MacDonald *et al*, "Demand Response Providing Ancillary Services: A Comparison of Opportunities and Challenges in the US Wholesale Markets". *Grid Interop Forum 2012*.

the cost of the equipment alone. Deferring or avoiding major distribution and transmission upgrades can reduce societal costs associated with those upgrades.

- *Non-event day energy savings.* CECONY's direct load control devices provide customers the ability to remotely control air conditioners and can lead to non-event day energy savings. DLRP and CSRP may also lead to non-event energy savings since several aggregators install energy management systems for customers they enroll. However, because non-event day saving were not estimated as part of the 2012 evaluation, this benefit was not included in the cost-effectiveness analysis.

These additional potential benefits are not included in the cost-effectiveness analysis. However, the model is designed to incorporate other user defined benefits on a per-kW, per-kWh, per customer or fixed basis; provided CECONY has data to substantiate them. It should also be noted that, because none of these additional benefits are currently accounted for, the benefit-cost ratios discussed in Sections 5 and 6 may understate the actual program benefits.

3.5 Overview of Program Cost Categories

Table 3-5 summarizes some of the key costs and incentives for each program. Whether incentive payments are viewed as a cost, a transfer or a benefit depend on the analysis perspective. They are included in the table because they are a central component of the program expenses. In the cost-effectiveness and sensitivity analysis, the cost inputs were placed into four primary categories:

- *One-time costs or incentives tied to enrollment*. These are costs that are incurred when a customer is initially enrolled. They can be in the form of equipment and installation costs, acquisition costs, sign up incentives or other costs. Their defining characteristic is that they do not recur annually.
- *Recurring costs or incentives tied to enrollment*. These costs are incurred annually but grow or decrease as enrollment changes. They can be in the form of recurring customer engagement costs, equipment monitoring or annual incentive payments.
- *One-time costs <u>not</u> tied to enrollment.* These are mainly program set up costs incurred when a program is developed and initially launched. They are not recurring and are not tied to the number of enrollments. They include components such as developing IT systems for settlement, initial market research to inform program design and other similar key components.
- *Recurring costs or incentives <u>not</u> tied to enrollment*. These costs are incurred annually and do not change materially with program expansion or contraction. They are often referred to as overhead costs. They typically include the personnel costs required to administer the program.

With more than $2.5 million spent annually, Residential DLC has the largest annual fixed overhead costs. Mass market programs, such as DLC and the CoolNYC pilot, often require equipment, installation and sign up incentives, which are all included in the one-time costs tied to enrollment. However, recurring costs tied to enrollment for these programs are minimal. In contrast, the majority of expense for large customer DR programs is for annual recurring incentive payments to participants.

Table 3-5: Cost Summaries for each Program

Program	One-time Tied to Enrollment (Variable costs)	Recurring Tied to Enrollment (Variable)	One-Time Not Tied to Enrollment (Fixed Costs)	Recurring Not Tied to Enrollment (Fixed Costs)
DLRP	▪ There were no costs in this category. These costs may be incurred by aggregators and participants, but are not directly observable and are captured by the assumption that 75% of payment incentives are for DR deliver costs.	▪ Summer Option Payment of $18 (Tier 1) or $36 per kW (Tier 2) for Mandatory option; $0 for Voluntary ▪ Annual Performance Payment of $0.50/kWh for Mandatory option and $1.50/kWh for Voluntary	▪ Equipment and Communications $127,472 ▪ Marketing $64,756	▪ Administrative (CECONY) $537,941 ▪ Measurement and Verification $526,383
CSRP	▪ There were no costs in this category. These costs may be incurred by aggregators and participants, but are not directly observable and are captured by the assumption that 75% of payment incentives are for DR delivery costs..	▪ Annual Option Payment of $30 for Mandatory; $0 for voluntary ▪ Annual Performance Payment of $0.50/kWh for Summer Reservation and $1.50/kWh for Voluntary	▪ Marketing research $100,000	▪ Administrative (CECONY) $245,000 ▪ Measurement and Verification $260,000
Business DLC	▪ Participant sign-up incentives for acquisition efforts – $50 per customer ▪ Equipment and installation costs – $300 per device ▪ Other one-time costs per device – $133	▪ Other annual variable costs $17 per device per year	▪ There were no costs in this category	▪ Administrative costs $466,251
Residential DLC	▪ Participant sign up incentives – $25 per device ▪ Equipment and Installation Cost – $300 per device ▪ Other one-time costs $108 per device	▪ Other annual variable costs $39 per device per year	▪ There were no costs in this category	▪ Administrative (Vendor) $1,928,039 ▪ Administrative (CECONY) $457,335 ▪ Other fixed costs $144,816
CoolNYC	▪ Participant sign up incentives $25 per household or $10 per device that is activated ▪ Equipment Cost – $115	▪ Annual fixed incentive $25 per participant who plugs in device. Customers, on average, have 2.5 room air conditioners and, historically, only 40% devices are plugged in.	▪ There were no costs in this category	▪ Administrative (CECONY) $32,809 ▪ Administrative (Vendor) $497,410 ▪ Measurement and Verification $53,160

3.6 Overlap of DR programs

CECONY's DR programs do not operate in isolation. Many large customers that have enrolled in CECONY's DR programs were either already enrolled in NYISO programs or enrolled in both NYISO and CECONY programs in close succession. As noted earlier, 70% of the pledged demand reductions enrolled in DLRP and CSRP were also enrolled in NYISO programs. The NYISO programs compensate customers for a different benefit stream, namely reductions designed to avoid generation capacity costs, as opposed to CECONY's programs, which compensate customers for providing distribution load relief. The cost-effectiveness analysis avoids double counting of generation avoided capacity costs for these customers. The measures to avoid double counting were described earlier, in Section 3.4.1.

CECONY's programs benefit from the presence of NYISO DR programs and NYISO program benefit from the presence of CECONY programs. The presence of these programs lowers the cost of enrollment and also expands the market potential since, for some customers, the incentives offered by CECONY or NYISO alone would be insufficient to spur participation. Without the presence of NYSIO programs for avoided capacity, CECONY's cost for administering the program would be different, but so would the benefits. The ideal approach would be to jointly assess the cost-effectiveness of the overlapping portion of the CECONY and NYISO large customer DR portfolios. However, the data was not available to do so but may be pursued for future assessments.

It also could be argued that, absent CECONY's programs, NYISO programs might provide some distribution relief. Some network peaks coincide with or overlap with NYISO system peaks. When NYISO events are called, the reductions also provide some load relief for the distribution system. In order for DR to avoid distribution costs, however, it must be incorporated into planning. This requires the ability to control DR resources rather than rely on the chance that the NYISO might (or might not) dispatch resources when they are needed for load relief. When participants enroll in CECONY programs, they explicitly provide CECONY with the ability to dispatch demand reductions when they are needed to provide relief for distribution. Those are often called on days when NYISO programs are not activated. In 2010, 2011 and 2012, on average, 75% and 64% of DLRP and CSRP activations, respectively, took place on days when NYISO programs were not activated. When NYISO event days coincide with distribution peak days, the event hours do not always match the times when relief for the distribution network is useful. When customers enroll for NYISO and CECONY programs, they may need to reduce demand more than once on a given day or sustain reductions for a longer period of time. For example, a customer may have to reduce load earlier in the day to comply with a NYISO event and sustain those reductions well after the NYISO event ends because reductions are still needed to reduce the stress on the distribution network.

In addition, there is substantial overlap between CSRP and DLRP participation. Of the 78.9 MW of pledged reductions enrolled in CSRP, 96% is from customers that are also enrolled in DLRP. The program overlap is substantial enough that these programs are analyzed jointly as a portfolio rather than independently. The portfolio analysis avoids counting the same benefit from the same customer twice but at the same time tracks all costs. This is accomplished by only counting CSRP benefits from customers who are not dually enrolled. The benefits and costs of each program and program option are calculated separately and then aggregated for the portfolio analysis.

4 Network Groups

As discussed at the beginning of this report, CECONY's DR programs are designed primarily to provide relief to the distribution system when demands are high or when emergency conditions occur. This is in contrast to the objective of DR at most other utilities, which is to reduce peak demands on generation. CECONY's distribution system is quite unique and the framework and model developed to assess cost-effectiveness of DR in this context must reflect the unique characteristics of the CECONY distribution system. This section summarizes some of the key characteristics of the distribution system that are captured in the DR cost-effectiveness framework.

There are 64 distinct networks and 19 non-network areas within the CECONY distribution system[24] and the value of DR varies across areas. Peaks on each network are concentrated in specific months and hours. In addition, the amount of DR needed and the timing of DR events is not the same for every network. Each network area also has a different amount of excess distribution capacity and a different network reliability index (NRI) score, both of which affect the timing and magnitude of distribution investments. Because network characteristics directly affect value and the degree to which DR can be used to manage peaks, it was critical to avoid assuming that all distribution areas are alike and to develop a model with sufficient granularity to reflect key differences. This required categorizing the CECONY distribution system into similar groups based on network/non-network status, load shapes, amount of excess capacity and NRI scores. This section discusses in more detail: the diversity of peaking conditions for network groups; documents how each distribution area was classified; explains how we calculated the concentration of when each networked group peaks; and details how DR reductions were aligned with peaking conditions.

4.1 Network Groups

There are four main factors that affect the value of DR in a distribution system. The first is distribution design. Within CECONY's distribution system, there are two types of load areas: those served by networks and those served by radial systems. Within a network, the benefits of DR are spread down to secondary level distribution investments because the network provides multiple and alternate paths for power to flow to each individual customer. In a radial (or non-network) system, reducing loads does not necessarily lead to lower secondary distribution system costs because there are not necessarily multiple pathways to deliver power to customers if a secondary voltage cable is placed out of service.

The second main factor that affects the value of DR in a distribution system is the concentration of peaks within a network. It is important to know how many hours of load relief are needed and when those hours occur. For example, a program with a maximum event duration of four hours will not alleviate a network with an eight-hour long peak period, unless half of the DR resource is called for the first four hours and half for the second four hours. Similarly, an evening peaking network will not be relieved by a DR program that can only be called earlier in the day.

Figure 4-1 reflects the average load shape for all distribution areas on the 20 highest CECONY system load days across 2010, 2011 and 2012. The graphs are normalized so they can be placed on the

24 ConEdison. *2012 Electric Distribution System Manual*. Produced by Distribution Engineering.

same scale. The value on the y-axis represents the percentage of load that occurs in each hour – loads for the entire day add up to 100% for each network. The graph illustrates the diversity of distribution load shapes across distribution areas, even for the same days and hours. The loads for different distribution areas are not alike and some degree of granularity is necessary to properly value DR designed for distribution relief.

Figure 4-1: Average Load Shape for Top 20 Highest Load Days (2010-2012) By Distribution Area

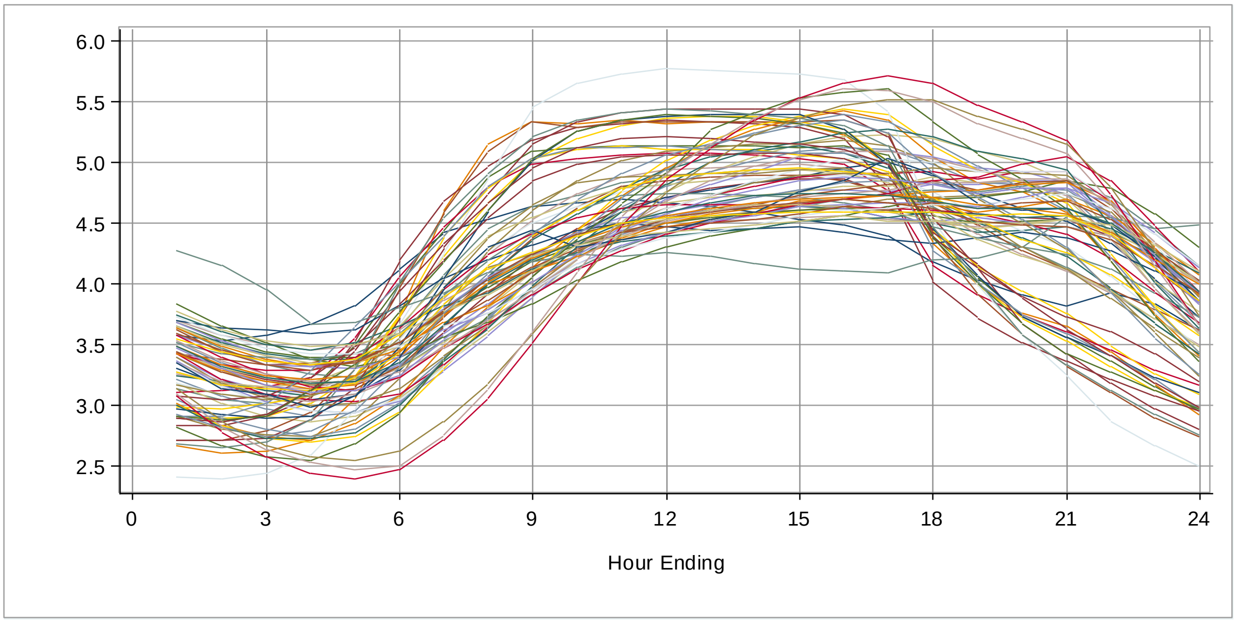
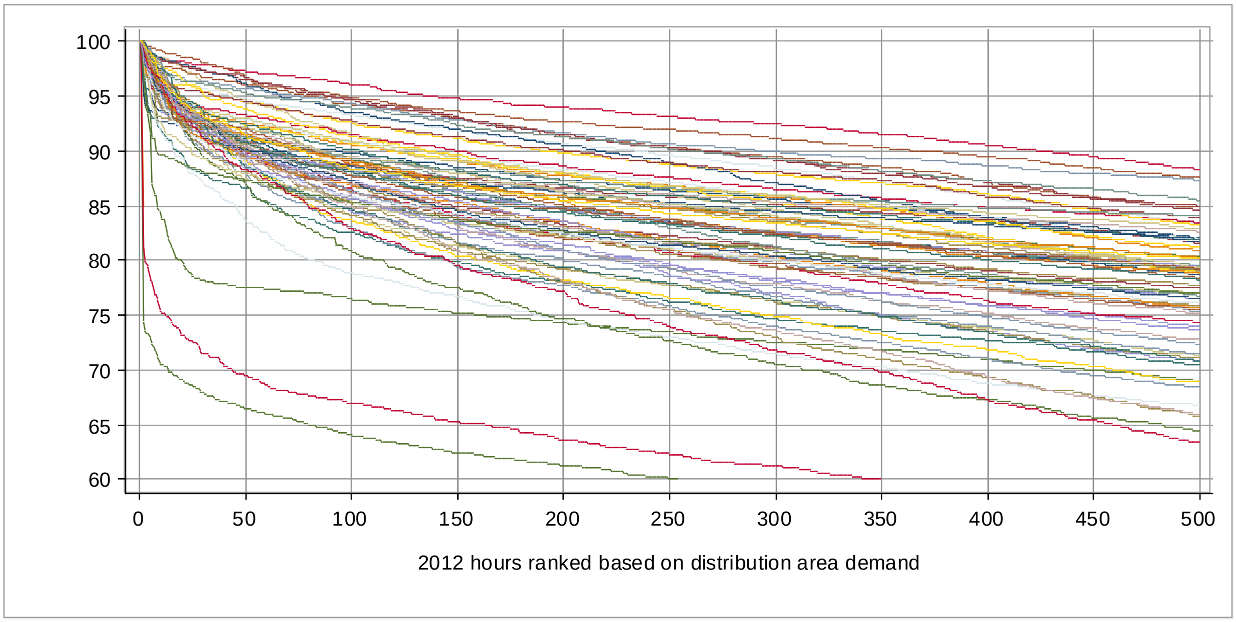


Figure 4-2 presents 2012 load duration curves for the top 500 hours of load for each network and reflects the concentration of load on peaking conditions. A load duration curve ranks demand for each hour of the year starting with the hour with the highest demand.

The networks with steep slopes are those that benefit the most from DR. In these networks, reducing loads even for a very limited number of hours substantially reduces peak demand, as long as reductions are properly targeted at the highest demand hours. The networks with the shallowest slope are those that do not have highly concentrated peaks. DR is less valuable in these networks because it is difficult to shave the peak when it occurs across so many hours. Even if demand during the top 50 hours is reduced, the next 50 hours would still have very high loads. While DR can help reduce the number of hours and the extent to which distribution components are overloaded, on its own, it is insufficient to fully manage loads in these distribution areas. Appendix D identifies the networks where DR resources most effectively reduce peak demands.

Figure 4-2: 2012 Load Duration Curves by Network



The immediacy of a major distribution investment is the third factor that influences the value of DR in a network. The value of DR is greater for networks in which there is not a large amount of excess capacity. These networks are closer in time to distribution investments that could be avoided by the use of DR programs.[25] Networks with limited excess capacity typically have lower reliability because feeder loads are more likely to exceed normal equipment ratings. However, there are many networks that have high excess distribution capacity but are less reliable than the typical CECONY network; DR is more valuable in these networks as well. The reliability of networks is measured using a Network Reliability Index (NRI) score, which indicates the likelihood of cascading feeder failures. Other factors that affect reliability besides excess capacity include: the number, type and age of the feeder cable sections, joints and the transformers that the feeder supplies; hotter temperatures, which lead to higher failure rates; and the presence of sectionalizing switches, which prevent cascading feeder outages. Because of this, both the NRI score and excess capacity are taken into account when determining network groups. The distribution areas with the highest NRI scores are considered Tier 2 networks and DR programs provide premium payments for reductions on higher risk networks.

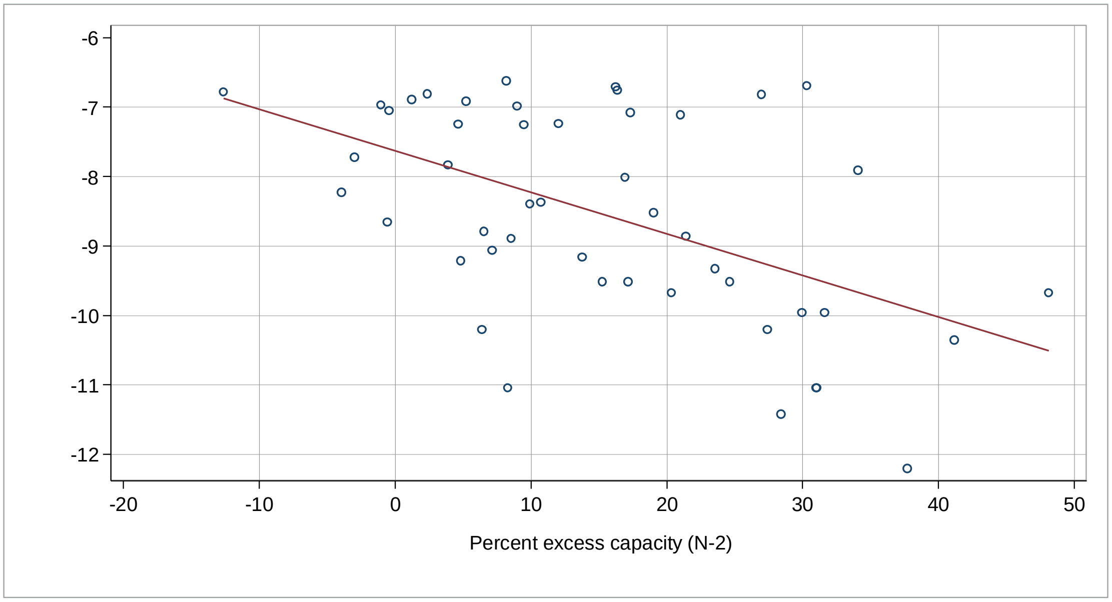
[25] Excess capacity can be calculated by dividing the peak load for a distribution area by the normal ratings of the distribution equipment. However, because CECONY's planning criteria calls for the ability to support loads uninterrupted even in the absence of the largest two feeders or other large components, the N-2 criteria was incorporated in the definition of excess capacity by subtracting the capacity, based on normal equipment ratings from the two largest feeders. The formula used to calculate excess capacity for each network is:

$$\textbf{excess capacity}_i = 1 - \left(\sum_{j=1}^{n} Load_{i,j} \Big/ \sum_{j=1}^{n-2} Normal\ Rating_{i,j} \right)$$

where *i* is an indicator for the distribution area, *j* is an indicator for each feeder and *n* is the number of feeders in the distribution area.

Figure 4-3 plots the natural log of NRI scores against the remaining capacity by network, assuming the two largest feeders are out of service (N-2 conditions). NRI scores can differ by a factor of 90 and, as a result, are more easily depicted on a log scale.

Figure 4-3: Relationship Between NRI Score and Excess Capacity



The higher the excess capacity with N-2 conditions, the lower the risk of cascading outages, as reflected by lower NRI scores. This is not surprising. A network with more insurance, in the form of excess capacity, will be more reliable. The excess capacity remaining after N-2 conditions does not fully explain the reliability scores, however, because the other factors mentioned also influence reliability.

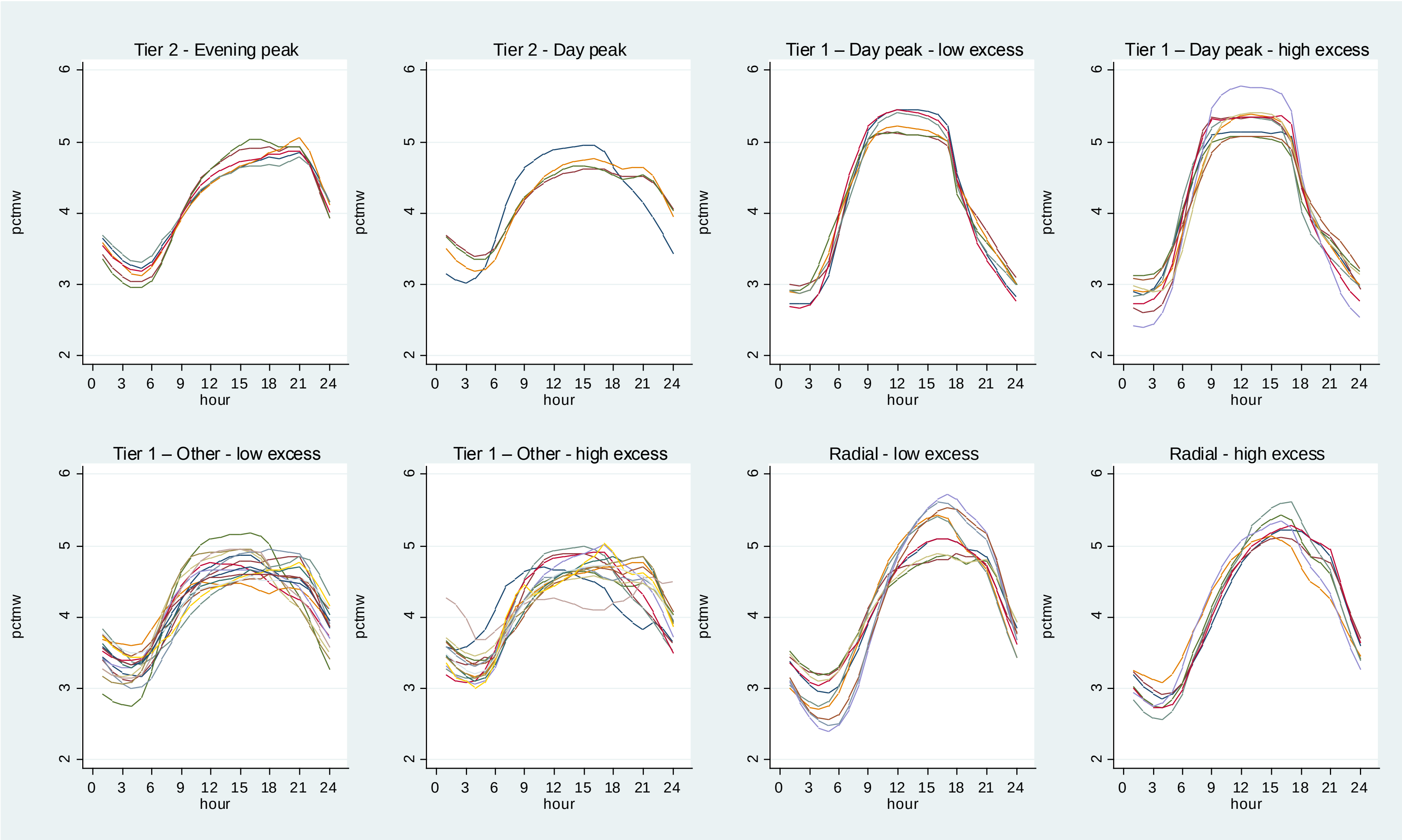
The fourth network characteristic that affects the value of DR is the rate of load growth within a network. If demand is growing rapidly on a network, the same percentage load reduction will not defer investments for as long as it would on a network where demand is growing more slowly. This factor can be incorporated by including different avoided T&D costs for each network group.

The first three key factors – network/non-networked status, load shape and immediacy of investment need as measured by excess capacity and NRI score – were used to group distribution areas into eight categories. Figure 4-4 presents normalized load shapes for each network group. While there is still some diversity within each category, each group contains networks that are similar to each other in terms of their shape, immediacy of need for distribution investments and the degree to which peaks that drive investments are shared.

The logic for the network groups is straightforward. First, the networks were classified into three main groups, network areas with high NRI scores (Tier 2), network areas with lower NRI scores (Tier 1), and non-network or radial system areas. A closer examination of these broader groups revealed that radial networks in general had similar load shapes mainly because they are primarily residential and evening peaking. The radial networks were sub-divided into high and low excess capacity based on the median excess capacity, 15%. The Tier 2 networks were sub-divided based on load shape since they are all high priority networks. The Tier 1 networks constituted the majority of the networks and were sub-divided into four categories based on load shape and whether they had high (>15%) or low excess capacity. The classification of networks to different load shapes was based on the ratio of demand during evening hours to demand during daytime hours.[26]

[26] The cut-off point was selected based on cluster analysis, which is a statistical technique to develop natural groupings.

Figure 4-4: Normalized Load Shapes by Network Classification

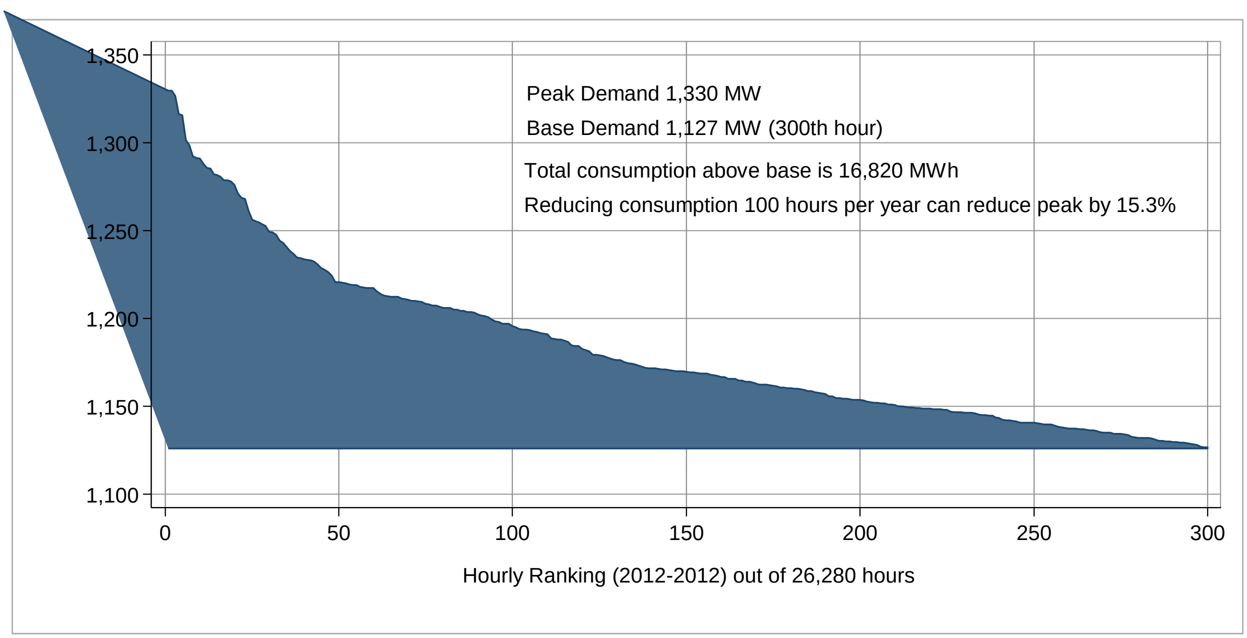


4.2 Concentration of Peaks Across Months and Hours

A key factor influencing DR benefits is the timing of when networks are most likely to peak (and more likely to overload) and how well DR resources align with those needs. It is critical to understand if DR resources are available to meet not just the annual peak but other hours that are near the peak and whether those hours are concentrated in specific months and hours. For simplicity, we refer to this as the concentration of need. Throughout this section, we use the Tier 2 evening peak network group to illustrate the concentration of peaking risk and its allocation across different months and hours. The process to identify and allocate peaking risk is the same for all eight network groups, although the values do vary by network group. The main difference across the network groups is the timing of when peaking conditions are most likely to occur.

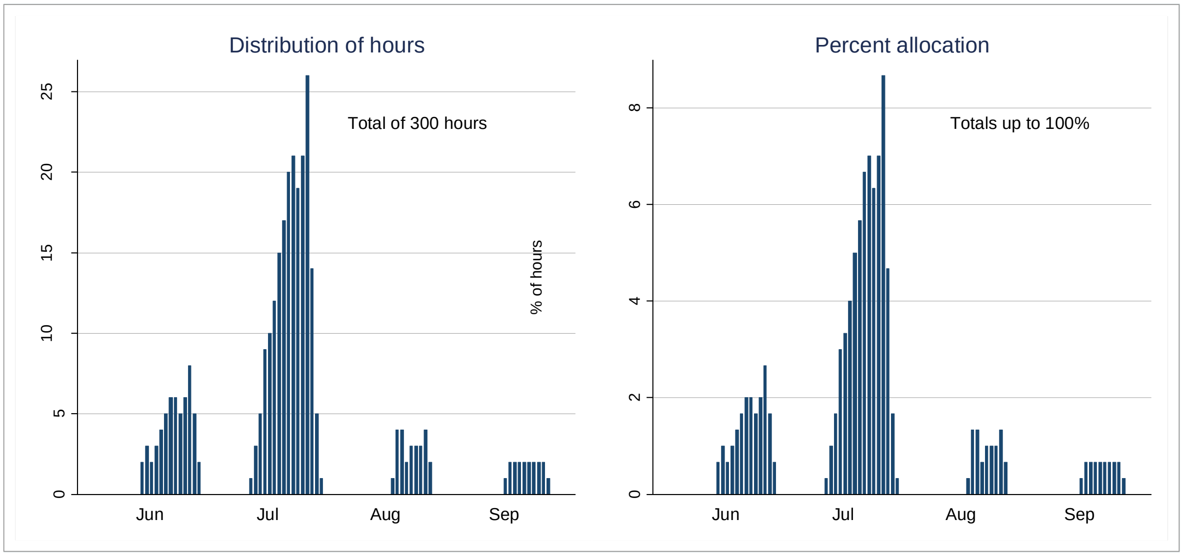
The concentration of need is best illustrated through a load duration curve, as illustrated in Figure 4-5 for a specific network group – Tier 2 evening peaking networks. Jointly, these networks have combined peak demand of 1,330 MW, but for 98.9% of hours, electricity demand is less than 1,127 MW. Reducing demand for 100-hours per year can potentially lower peak demand by up to 15.3%, if targeted precisely. The total area under the curve reflects the reduction in consumption necessary to reduce the peak by 15.3%.

Figure 4-5: Illustration of Concentration of Peak Loads – Tier 2 Evening Peaking



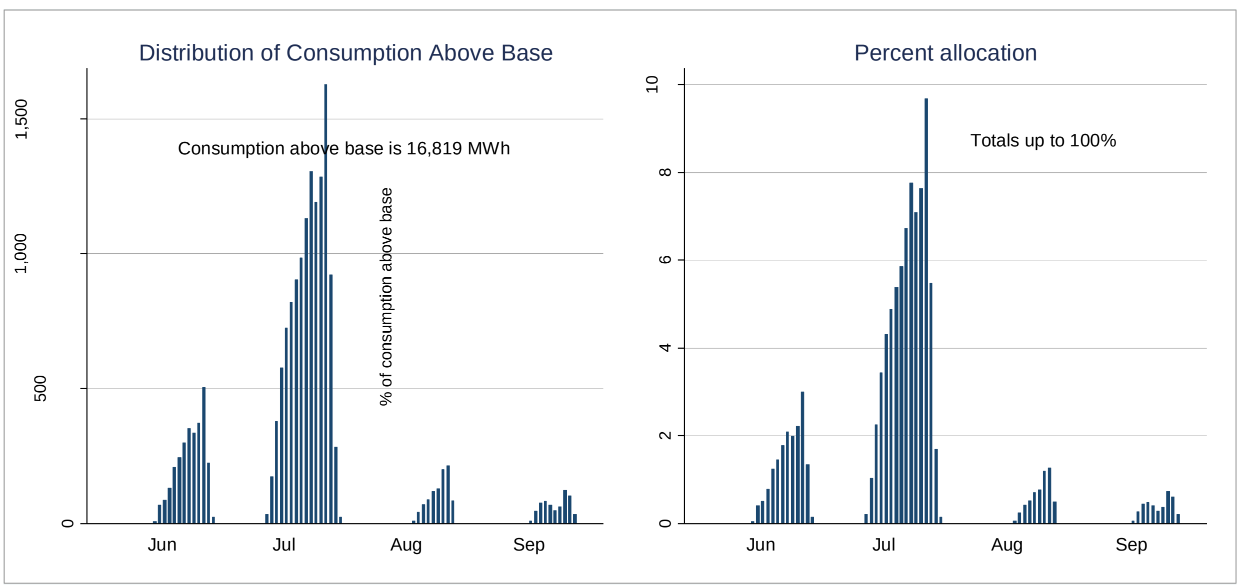
It is critical to understand if peak demands are concentrated in specific months and hours. Figure 4-6 visually presents the months and hours when the top 300 load hours occur for the network group across 2010, 2011 and 2012 (100 hours per year). It is based on the aggregate load for Tier 2 evening peaking networks. As expected, the hours are highly concentrated in summer months and in the evening. None of the highest load hours occurred outside of June through September. This is true for all network groups, not just Tier 2 evening peaking networks.

Figure 4-6: Example Concentration of Highest Demand Hours By Month and Hour



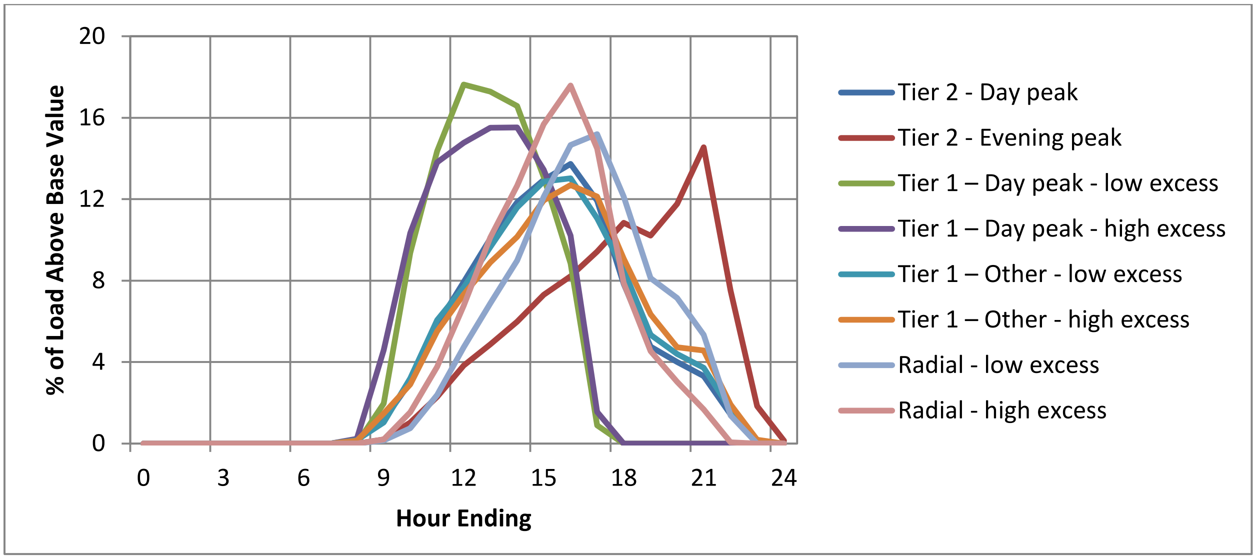
While it is useful to understand when the networks are likely to peak, the risk of overloading feeders and cascading feeder outages is higher on the peak hour than on the 300th highest load hour (across the three years). In other words, the need for load relief is more acute when electricity demand is higher. Another way to assess the concentration of peak load is to calculate the distribution of total consumption above a base value across months and hours. The base value was based on the demand level on the 100th hour of the load duration curve. When analyzed over three years (2010-2012), the demand on the 300th hour (100 x 3) was used instead. Figure 4-7 illustrates the total consumption above the base value (1,127 MW) for the example network group both in an absolute and on a percentage basis.

Figure 4-7: Example Concentration of Load Above Base MW by Month and Hour



The likelihood of high loads that stress the distribution system is highly concentrated in specific months and hours. However, the degree of concentration varies across the eight different network groups and affects how valuable DR is in each network group. The biggest variation across the eight different network groups is the concentration of high loads across hours. Figure 4-8 compares the concentration of high loads for the eight different network classifications. For each network group, the allocation also adds up to 100%.

Figure 4-8: Concentration of Load Above Base MW by Month and Hour[27]



The key difference is that Figure 4-8 aggregates the concentration of loads above a base MW by hour of day. DR resources need to be available and activated on the right hours to deliver the most value. Ideally, a larger share of DR resources is dispatched for key hours. In many network groups, the concentration of peaks is spread over a large number of hours. DR resources can still be effective for these networks if they provide relief when it is needed most, but resources that can sustain reductions for a longer duration are more valuable in these networks.

The concept of the concentration of peak loads is critical to the valuation of DR. The availability of DR for specific hours and the extent to which DR resources coincide with the times when overloading is most likely to occur determine the extent to which DR can alleviate the risk of overloading networks and thereby reduce the risk of failures. This is particularly true for resources such as air conditioner load control where the magnitude of the reduction depends on weather conditions and hour of day. A key step is factoring in the coincidence of DR availability, the magnitude of load response and distribution network need.

[27] The base value is the demand level on the 100th hour of the load duration curve. When analyzed over three years (2010-2012), the 300th hour (100 x 3) was used.

Table 4-1: Example Concentration of Network Group Peak Loads by Hour and Month

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%
11	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%
12	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	4%
13	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%	5%
14	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%	6%
15	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%	7%
16	0%	0%	0%	0%	0%	1%	6%	0%	0%	0%	0%	0%	8%
17	0%	0%	0%	0%	0%	2%	7%	1%	0%	0%	0%	0%	9%
18	0%	0%	0%	0%	0%	2%	8%	1%	0%	0%	0%	0%	11%
19	0%	0%	0%	0%	0%	2%	7%	1%	0%	0%	0%	0%	10%
20	0%	0%	0%	0%	0%	2%	8%	1%	1%	0%	0%	0%	12%
21	0%	0%	0%	0%	0%	3%	10%	1%	1%	0%	0%	0%	15%
22	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%	8%
23	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%	2%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	0%	0%	0%	0%	0%	17%	73%	6%	4%	0%	0%	0%	100%

The peaking risk allocation for different network types can be represented by a matrix like the one shown in Table 4-1. The table reflects when a network type is most likely to peak, by hour and month. Each entry represents the percent of total consumption above the base value (MW at the 300th highest load hour in the past 3 years) across months and hours. The allocation across all hours and months totals 100%. The yellow bars visually reflect the percent allocation to each time period. For this particular network type, DR is more valuable in the summer months, especially in July. The highest concentration of risk for this network type occurs between 8–9 PM in July, where 10% of the consumption above the base value occurred in the past three years. This hour carries the most value for DR because the historical data indicates that this time period carries the highest concentration of load. Additionally, this table can help determine the necessary event durations of various programs. For example, a resource that can sustain load reductions for six hours is more valuable than one available for only four or five hours. This is because a longer event can absorb more of the risk associated with system peaks.

We calculated the concentration of peak loads for each network as well as for the NYISO system. These tables are presented in Appendix E. The concentration of need in each network is used to determine how well different DR programs with different characteristics align with the concentration of need for each network group. The concentration of peak loads for the NYISO system is similarly used to assess how well DR programs *not* enrolled in NYISO programs (e.g., Direct Load Control) align with the concentration of need for generation capacity.

Load reduction capability can also be defined for each month and hour, which allows us to assess the coincidence between the system needs and the demand reduction availability and capability. This is discussed in the next subsection.

4.3 Coincidence of Demand Response Resources With Network Group Peaks – Factoring in DR Characteristics

DR resources can vary in terms of how well reductions coincide with peaking conditions, the availability and exhaustibility of the resource and how long they can sustain reductions. Constraints on the utilization of DR and how well reduction capabilities coincide with specific system needs both play a critical role in valuation. To properly value DR, it is necessary to adjust it for program characteristics and how well the reductions coincide with distribution capacity needs.

A program that can be dispatched for both system peaking conditions and emergencies as long as needed whenever it is needed has more value than a program with limitations on when or how long it can be dispatched. A program that delivers larger demand reductions when they are most needed has more value than one for which the magnitude of reductions do not coincide well with distribution or system needs.

Throughout this section, we use Residential DLC to illustrate how DR characteristics are factored into the valuation. The concepts presented apply to other DR programs but are generally less complex to implement, particularly for C&I DR programs which exhibit less variation in demand reductions. We use Residential DLC as an example because reductions for air conditioner direct load control vary with weather conditions, hour of day and number of hours into an event. While the reductions vary, they do so in a predictable manner. Load control also leads to small increases in demand outside of the event window because, after control is released, air conditioners need to run longer to cool the building down to the desired set point. It is important to assess if rebound or snapback coincides with periods when network loads are still high and not to ignore spillover effects in valuation.

Figure 4-9 shows the variation in air conditioner loads and reductions. It depicts all four events in 2011 and 2012 when all DLC resources were called. Two of those days, July 21, 2011 and July 22, 2012, met conditions that trigger peak shaving events. There were substantial temperature differences between the two peak shaving days and the other two days when program wide events were called. The top portion of the graph shows the air conditioner demand per unit, which is based on the control group. The bottom graph shows the hourly demand reductions, which were calculated as the difference between the control and curtailment groups. Several factors are noteworthy. The air conditioner load for each of those days varied in magnitude and shape. Not surprisingly, reductions were larger on days when air conditioner use was highest. The reductions were well over 1 kW on the hotter days that met the peak shaving criteria. The event duration and start times also varied for each of the four events based on the resources that were needed on those days.

Figure 4-9: Variation in Residential Air Conditioner Demand and Load Control Curtailments

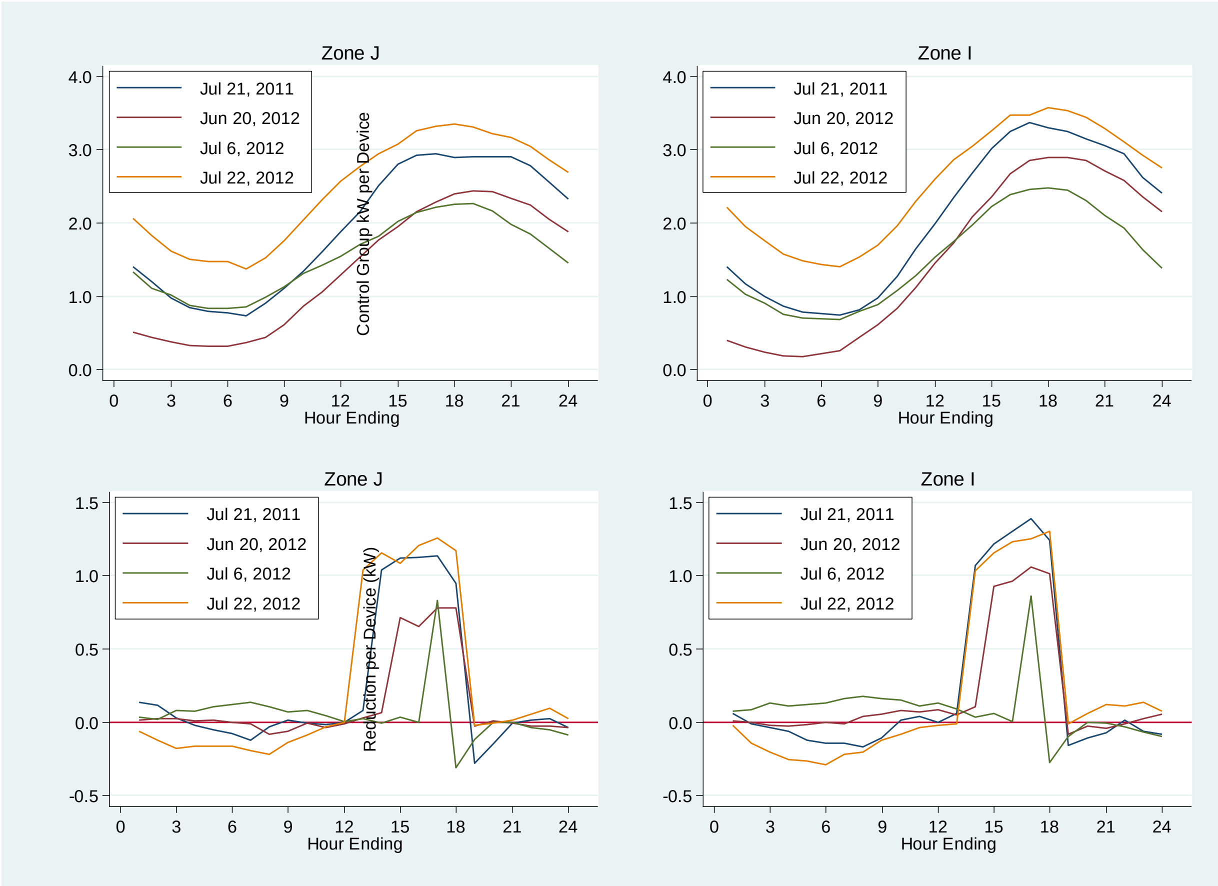


Table 4-2 compares side-by-side an evening peaking network group and a day peaking network group. For each network, the table shows the concentration of peaking risk (blue bars) and the hourly demand reductions per device (green bars).[28] The demand reductions in the day and evening peaking network groups are assumed to start at 12 PM and 5 PM, respectively, and assume a five hour event. For now, we assume the reductions must start at those times and that they can only be sustained for 5 hours. This assumption is useful for demonstrating the effect of fixed event windows on the value of DR. In reality, CECONY programs are far more flexible and can start at different times and sustain reductions for longer periods, if needed.

Not surprisingly, the risk of high loads on the evening peaking network group is high between 5 and 10 PM. However, the peaking risk is not exclusively concentrated in those hours; approximately 45% of the risk falls outside of those hours. Loads are highest in the evening hours but they are also very high earlier in the day. In contrast, the peaking risk for the day peaking network is more highly concentrated; nearly all of it is allocated to the hours between 9 AM and 4 PM. However, the fixed

[28] The concentration of peaking risk for each of the network groups was developed using the process described in Section 4.2 and add up to 100% across all hours of day.

event window, from 12 to 5 PM, does not align well with the times when the network group is most likely to peak.

Table 4-2:
Adjusting Reductions for Constraints and Coincidence with Peaking Risk Allocation (Example with Limited Dispatch Flexibility)

Hour (start)	Tier 2 - Evening Peaking			Tier 1 - Day peaking, low excess capacity		
	Peaking Risk Allocation	Demand Reduction per Device (kW)	Adjustment Interim Calculation	Peaking Risk Allocation	Demand Reduction per Device (kW)	Adjustment Interim Calculation
	(A)	(B)	(A x B)	(A)	(B)	(A x B)
0:00	0.0%	0.00	0.00	0%	0.00	0.00
1:00	0.0%	0.00	0.00	0.0%	0.00	0.00
2:00	0.0%	0.00	0.00	0.0%	0.00	0.00
3:00	0.0%	0.00	0.00	0.0%	0.00	0.00
4:00	0.0%	0.00	0.00	0.0%	0.00	0.00
5:00	0.0%	0.00	0.00	0.0%	0.00	0.00
6:00	0.0%	0.00	0.00	0.0%	0.00	0.00
7:00	0.0%	0.00	0.00	0.0%	0.00	0.00
8:00	0.2%	0.00	0.00	2.0%	0.00	0.00
9:00	1.0%	0.00	0.00	9.4%	0.00	0.00
10:00	2.3%	0.00	0.00	14.4%	0.00	0.00
11:00	3.8%	0.00	0.00	17.6%	0.00	0.00
12:00	4.9%	0.00	0.00	17.3%	0.76	0.13
13:00	6.0%	0.00	0.00	16.6%	0.94	0.16
14:00	7.3%	0.00	0.00	13.1%	0.98	0.13
15:00	8.2%	0.00	0.00	8.8%	1.06	0.09
16:00	9.4%	0.00	0.00	0.9%	1.15	0.01
17:00	10.8%	1.21	0.13	0.0%	-0.21	0.00
18:00	10.2%	1.01	0.10	0.0%	-0.06	0.00
19:00	11.8%	0.97	0.11	0.0%	-0.02	0.00
20:00	14.5%	0.93	0.14	0.0%	0.00	0.00
21:00	7.5%	0.71	0.05	0.0%	0.01	0.00
22:00	1.8%	-0.18	0.00	0.0%	0.00	0.00
23:00	0.1%	-0.05	0.00	0.0%	0.00	0.00

Max Reduction (kW)	**1.21**	**Max Reduction (kW)**	**1.15**
Adjusted Reduction (kW)	**0.53**	**Adjusted Reduction (kW)**	**0.52**
$\sum_{h=1}^{24}(A_h \text{ x } B_h)$		$\sum_{h=1}^{24}(A_h \text{ x } B_h)$	

Because of the fixed event window, the availability of the resources and the length of time reductions can be sustained do not fully align with when load relief is needed most and must be adjusted for the cost-effectiveness valuation. It is inappropriate to credit the resource based on the maximum reduction, although this is not an uncommon practice. Reductions are still valuable. They can eliminate or reduce how often and for how long distribution components are overloaded. By providing load relief, reductions also reduce the likelihood of additional failures.

The above example highlights the need to adjust DR value to account for limits on availability and event duration as well as for how reductions coincide with peaking conditions. One way to make this adjustment is to weight the load reduction capability in each hour by the peaking risk allocated to each hour. Since the allocation adds up to 100%, this is accomplished by multiplying reductions by the risk allocation for each hour and summing up those values. This provides an estimate of load carrying capacity that factors in program constraints and how well reductions coincide with need.

For the evening peaking network, the coincidence adjusted reduction is 0.53 kW, which amounts to 44% of the maximum reduction delivered. For the day peaking network, the coincidence adjusted reduction is 0.52 kW, or 45% of the maximum reduction during the event window. There are three main ways to improve the value of the resource:

- Allow for flexible start times;
- Remove limits on the event duration; or
- Manage load control so reductions are highest when they are most needed.

Allowing flexible start times and removing or expanding limits on event duration facilitate better targeting of peaking conditions. Under extreme conditions, reductions may need to start earlier and be sustained for longer periods of time. This is particularly true for networks with long peak periods, where loads on many hours are close to the peak load. Providing a program with the option of calling events up to, for example, eight hours does not mean that option would be exercised each time the program is called. Such dispatch should be reserved for instances when it is definitely needed. A third option is to manage dispatch so specific amounts of reduction are delivered for specific hours. This can be complex and requires dispatching different resources on a network at different times so reductions are highest when they are most needed and lower when the need is critical but not acute. With such an approach, reductions may occur over a longer period, such as eight hours, but each customer might only be controlled for four hours.

Table 4-2 shows how allowing flexible start times and expanding the artificial limit on event durations from five to six hours leads to reductions that better coincide with peaking conditions. In both cases, DR resources are dispatched earlier to better align with peaking conditions. The coincidence adjusted reductions for the evening peaking network increase from 0.53 kW to 0.85 kW, a 60% improvement. The coincidence adjusted reductions for the day peaking network improve but not nearly as much, going from 0.52 kW per device to 0.69 kW per device, a 31% improvement. Shifting the event window to an earlier time better aligns reductions with peaking conditions, but the reductions are smaller because residential air conditioner use is not at its peak. Having the option to sustain reductions for longer typically has a direct effect on value. However, that effect is muted when the magnitude of reductions does not coincide with the hours when loads are highest.

Table 4-3:
Adjusting Reductions for Constraints and Coincidence with Peaking Risk Allocation (Example with More Dispatch Flexibility)

Hour (start)	Tier 2 - Evening Peaking			Tier 1 - Day peaking, low excess capacity		
	Peaking Risk Allocation	Demand Reduction per Device (kW)	Adjustment Interim Calculation	Peaking Risk Allocation	Demand Reduction per Device (kW)	Adjustment Interim Calculation
	(A)	(B)	(A x B)	(A)	(B)	(A x B)
0:00	0.0%	0.00	0.00	0%	0.00	0.00
1:00	0.0%	0.00	0.00	0.0%	0.00	0.00
2:00	0.0%	0.00	0.00	0.0%	0.00	0.00
3:00	0.0%	0.00	0.00	0.0%	0.00	0.00
4:00	0.0%	0.00	0.00	0.0%	0.00	0.00
5:00	0.0%	0.00	0.00	0.0%	0.00	0.00
6:00	0.0%	0.00	0.00	0.0%	0.00	0.00
7:00	0.0%	0.00	0.00	0.0%	0.00	0.00
8:00	0.2%	0.00	0.00	2.0%	0.00	0.00
9:00	1.0%	0.00	0.00	9.4%	0.00	0.00
10:00	2.3%	0.00	0.00	14.4%	0.46	0.07
11:00	3.8%	0.00	0.00	17.6%	0.63	0.11
12:00	4.9%	0.00	0.00	17.3%	0.76	0.13
13:00	6.0%	0.00	0.00	16.6%	0.93	0.15
14:00	7.3%	0.00	0.00	13.1%	0.98	0.13
15:00	8.2%	1.49	0.12	8.8%	1.05	0.09
16:00	9.4%	1.59	0.15	0.9%	-0.21	0.00
17:00	10.8%	1.46	0.16	0.0%	-0.06	0.00
18:00	10.2%	1.25	0.13	0.0%	-0.02	0.00
19:00	11.8%	1.21	0.14	0.0%	0.00	0.00
20:00	14.5%	1.17	0.17	0.0%	0.01	0.00
21:00	7.5%	-0.19	-0.01	0.0%	0.00	0.00
22:00	1.8%	-0.05	0.00	0.0%	0.00	0.00
23:00	0.1%	-0.01	0.00	0.0%	0.00	0.00

Max Reduction (kW)	**1.59**	**Max Reduction (kW)**	**1.05**
Adjusted Reduction (kW)	**0.85**	**Adjusted Reduction (kW)**	**0.68**
$\sum_{h=1}^{24}(A_h \text{ x } B_h)$		$\sum_{h=1}^{24}(A_h \text{ x } B_h)$	

The example illustrates the need to factor in limitations on availability and event duration as well as to account for how well reductions coincide with the need for load relief. In practice, CECONY's programs are very flexible. Most DR resources can be activated either because of high system loads or due to network specific emergency conditions. Program dispatch is typically limited to time periods, instances and networks where load relief is needed. When they are needed, nearly all of CECONY's programs can be triggered at different times and reductions can be sustained as long necessary. This option, which is exercised carefully, makes the programs more valuable. The sole exception is CSRP, which is only dispatched for five hours at a time, starting at either 12 PM or 5 PM depending on whether the network is day or evening peaking. While most CECONY programs do not have limitations on the maximum event duration, there is limited or no experience with events lasting longer than eight hours.

The cost-effectiveness analysis accounts for how well each of CECONY's programs coincide with the concentration of peaking risk for each network group, factoring in limitations such as availability, ability to vary start times and maximum event duration. In practice, the adjustment factors in coincidence with peaking condition by hour of day and month and can be summarized by the following equation:

$$Adjusted\ kW = \sum_{h=1}^{24} \sum_{m=1}^{12} Reductions_{h,m} \times Peaking\ Risk\ Allocation\ _{h,m}$$

5 Cost-effectiveness Analysis for C&I Programs

This section summarizes the cost-effectiveness analysis for CECONY's large commercial and industrial demand response programs: CSRP and DLRP. It examines the costs and benefits for each program and the degree to which various factors drive the programs' cost-effectiveness. Cost-effectiveness is inherently forward looking and typically tied to investments that require upfront costs but deliver benefits over a longer period of time. The cost-effectiveness analysis addresses two primary questions for each program:

- Is it cost effective to continue operation of the program without expansion? This scenario accounts for the fact that, in many instances, equipment and recruitment costs are sunk.
- Is it cost effective to add new enrollees? This scenario addresses the question of whether increased enrollment will increase or decrease overall program cost-effectiveness.

Both of these questions are addressed based on how the programs have historically operated, factoring in historical costs, event performance, dispatch practices and program rules. In other words, the cost-effectiveness estimates are based on how programs have performed and operated in the past, which may differ from how programs are operated in the future.

An important question is whether cost-effectiveness can be improved by adjusting program rules and operations or by more effectively targeting customers. We analyzed the key drivers of cost-effectiveness through sensitivity analysis. Sensitivity analysis is a systematic process for identifying the inputs that contribute most to key results such as the benefit cost ratio. This is typically accomplished by varying each component by a specific percentage, typically 20%, while holding all other inputs constant. Sensitivity analysis serves several functions:

- It helps identify which assumptions, inputs and program design characteristics contribute most to net benefits;
- It helps test the robustness of the results. If a program is cost-ineffective due to small changes in the inputs, it is not very robust, particularly if those values are uncertain;
- It helps users better understand the relationships between input variables and outcomes;
- It can help focus additional research on inputs and assumptions that drive cost-effectiveness. When inputs are highly influential, it is critical to assess the degree of uncertainty for them and determine if and how the uncertainty can be reduced; and
- It can help focus discussion and efforts on the program components that are most influential.

As noted earlier, both DLRP and CSRP have mandatory and voluntary options, which share overhead costs. For this reason, voluntary and mandatory options are analyzed jointly. In addition, as discussed in Section 3.6, there is substantial participation overlap between DLRP and CSRP and portfolio level analysis is required to avoid double counting. Under the portfolio approach, benefits from dually enrolled customers are only assigned to one program, while all costs from both programs are counted. The portfolio results are presented first, followed by sensitivity analysis.

The remainder of this section presents some of the key characteristics of the programs that are relevant to cost-effectiveness such as enrollment by network type, costs, incentive payments and demand reduction performance. Next, the portfolio level results are presented, along with sensitivity analysis at the portfolio level.

5.1 Program Information Related to Cost-effectiveness

Dual enrollment in CSRP and DLRP and the location of DR resources play a key role in cost-effectiveness. Table 5-1 summarizes the enrolled, pledged reductions (enrolled MW) in CSRP and DLRP, by program option and network type, as of August 2013. Because both programs require participants to pledge specific amounts of load reduction, the cost-effectiveness analysis treats each kW of pledged reduction as an enrollment unit. This was also done because payments to customers are based on pledged reductions. To avoid double-counting, only pledged reductions to DLRP are counted for dually enrolled customers. In total, there are 186.5 MW enrolled after accounting for dual enrollment. This is only slightly more than the DLRP program alone. CSRP had 63.3 MW (58.4+5) and 15.6 MW (15.5+1) enrolled in the mandatory and voluntary options, respectively, for a total of 78.9 MW. Of the 78.9 MW enrolled in CSRP, 73.9 MW (58.4+15.5), or 94%, was also enrolled in DLRP. The program overlap is substantial enough that it is difficult to view these programs independently and they are therefore assessed jointly. Without being able to dually enroll in CSRP and DLRP, it is likely that some customers would not participate in CECONY's program.

Table 5-1: Enrolled MW by Network, Program and Option

Network Type	CSRP				DLRP		Total (without dual enrollments)	Total (with dual enrollments)
	Mandatory		Voluntary					
	CSRP Only	Dually Enrolled	CSRP Only	Dually Enrolled	Mandatory	Voluntary		
Tier 2 – Day peak	0.3	2.2	–	2.3	7.8	3.5	11.6	16.1
Tier 2 – Evening Peak	0.6	5.7	–	0.1	14.6	0.9	16.1	21.9
Tier 1 – Day Peak, Low Excess	0.5	10.5	–	2.9	18.8	3.3	22.6	36
Tier 1 – Day Peak, High Excess	1.8	11.5	0.1	3.4	22.4	4.5	28.8	43.7
Tier 1 – Other, Low Excess	0.6	14.1	–	0.9	39.8	2.5	42.9	57.9
Tier 1 – Other, High Excess	1.1	14	–	5.5	45.6	6.5	53.2	72.7
Radial – Low Excess	0	0.4	–	0.5	4.8	0.7	5.5	6.4
Radial – High Excess	–	–	–	–	4.1	1.7	5.8	5.8
TOTAL	**5**	**58.4**	**0.1**	**15.5**	**157.9**	**23.5**	**186.5**	**260.4**

Another key factor that affects cost-effectiveness is retention rate, which affects the reduction capability (MW) in future years. It is particularly relevant for programs that require extensive efforts to enroll resources and those that involve equipment installation. With large customer programs, retention of pledged reductions often matters more than changes in customer counts. Retention can be a complex analysis because customers enroll and exit at different points in time. This analysis is further complicated by adjustments to the program. In 2012 and 2013, CECONY removed customers that did not meet metering requirements from the program and adjusted downward the pledged reductions for customers that historically had not performed well. This latter recalibration reduced the pledged reductions but is expected to result in an improvement in program performance.

Table 5-2 summarizes retention rates. It includes only customers that were enrolled in 2012 and shows the number of enrolled MW that remained in 2013. Failure to comply with pledged reduction in DLRP leads to reduced payments, while failure to comply with CSRP pledged reductions can lead to penalties. Retention rates are higher for voluntary options and for DLRP.

Table 5-2: Retention Rates by Program and Option

Program	Accounts			Enrolled MWs		
	2012	2013	Retention Rate	2012	2013	Retention Rate
CSRP Mandatory	248	176	71.0%	72.4	46.6	64.3%
CSRP Voluntary	51	36	70.6%	16.2	14.5	89.4%
DLRP Mandatory	756	529	70.0%	189.2	143.6	75.9%
DLRP Voluntary	54	50	92.6%	21.0	19.1	91.1%
Total	**1,109**	**791**	**71.3%**	**298.7**	**223.7**	**74.9%**

Table 5-3 summarizes the performance during event periods in 2011–2012, by network type, for the DLRP and CSRP Mandatory options. The table also includes the adjusted performance value, which factors in any program dispatch limitations, spillover into neighboring hours and the coincidence of reduction with network or NYISO system peaking conditions. The data sources and steps used to estimate the performance rates are described more fully in Appendix F. The process and steps for adjusting the performance value to account for program limitations and for the coincidence with network and NYISO system peaking conditions are described in Section 4.3.

Table 5-3: Performance Factors During Events and After Adjustment for Coincidence With Peaking Risk Allocation

Program	Network Type	Max. Event Reduction (performance factor)	Avg. Event Reduction (performance factor)	Adjusted for Coincidence (performance factor)
DLRP	Tier 2 - Day peak	50%	35%	39%
	Tier 2 - Evening peak	86%	54%	76%
	Tier 1 – Day peak - high excess	81%	56%	48%
	Tier 1 – Day peak - low excess	80%	56%	42%
	Tier 1 – Other - high excess	93%	59%	75%
	Tier 1 – Other - low excess	80%	54%	69%
	Radial - high excess	54%	43%	43%
	Radial - low excess	100%	80%	87%
CSRP	Tier 2 - Day peak	56%	39%	30%
	Tier 2 - Evening peak	133%	75%	110%
	Tier 1 – Day peak - high excess	62%	49%	32%
	Tier 1 – Day peak - low excess	64%	50%	17%
	Tier 1 – Other - high excess	104%	59%	69%
	Tier 1 – Other - low excess	105%	62%	85%
	Radial - high excess	84%	40%	64%
	Radial - low excess	91%	52%	70%

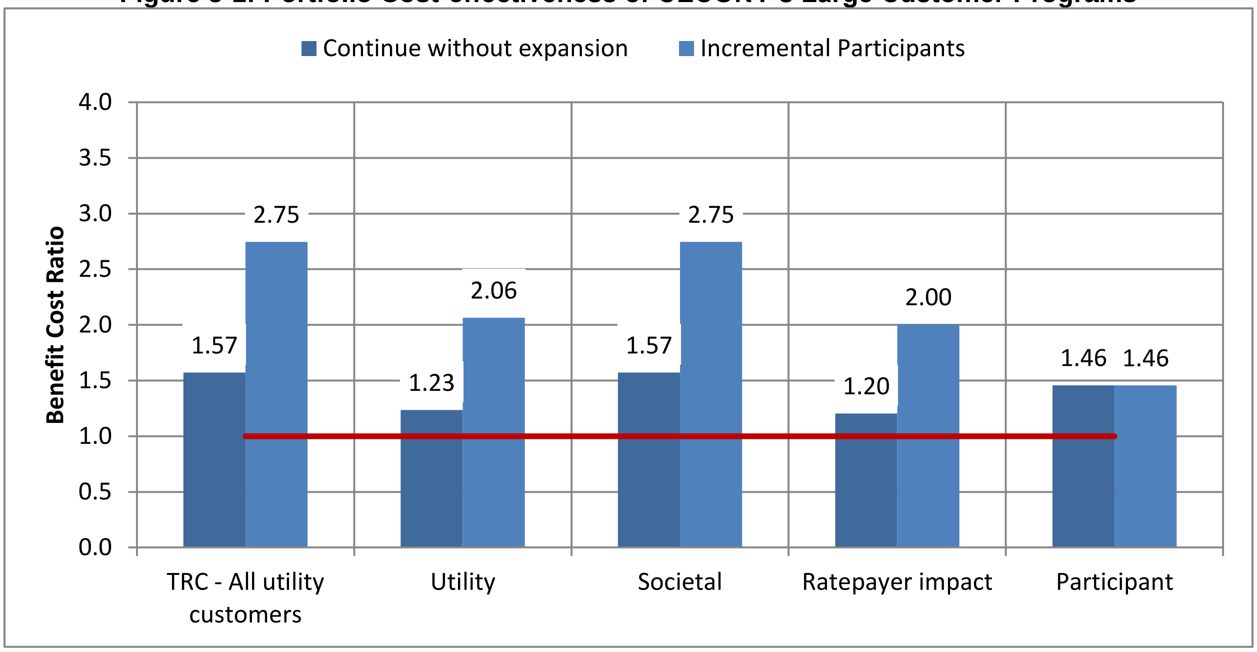
5.2 Portfolio Cost-effectiveness Results

Portfolio cost-effectiveness results assess DLRP and CSRP mandatory and voluntary options jointly. As noted, overhead costs for mandatory and voluntary options are shared and the overlap between CSRP and DLRP is substantial, making it difficult to assess their cost-effectiveness independently.

The goal of portfolio analysis is to avoid double counting of benefits. When customers are dually enrolled in CSRP and DLRP, the portfolio analysis attributes them to DLRP because incentive payments come from the DLRP budget. The net result is that benefits for dually enrolled customers are counted once and all overhead and payment costs are included in the portfolio analysis.

Figure 5-1 summarizes the joint cost-effectiveness of CECONY's large C&I programs - DLRP and CSRP – given a core set of assumptions.[29] The figure shows the benefit-cost ratio associated with continuing the program without additional enrollment, as well as for a scenario in which enrollment is expanded. The cost-effectiveness of continuing the program weighs the overhead and incentive costs of the program against the benefits of continuing operations for another year and includes fixed overhead costs. The cost-effectiveness of adding new participants weighs whether benefits associated with adding new participants outweigh the costs associated with enrolling them, installing equipment, paying incentives and continuing operation for over 10 years (accounting for annual attrition). Results are presented for each cost-effectiveness perspective. The TRC and societal values are always the same because environmental benefits and outage cost reductions were not quantified.

Figure 5-1: Portfolio Cost-effectiveness of CECONY's Large Customer Programs



At current enrollment levels, CECONY's large C&I programs are cost effective from each perspective. Without additional participants, the benefits of the programs outweigh the costs, including the overhead costs associated with implementing the programs. The benefit-cost ratio for the most relevant screen, the TRC test, is 1.57. This perspective looks at whether the program reduces the average utility customers' overall costs. The programs are also cost-effective from utility and non-participant ratepayer perspective, both of which count incentive payments as costs. The ratepayer impact test reflects whether rates would need to increase either to fund the programs or because energy savings lead to the need to collect the same amount of revenue (to cover capital infrastructure) from lower energy sales.

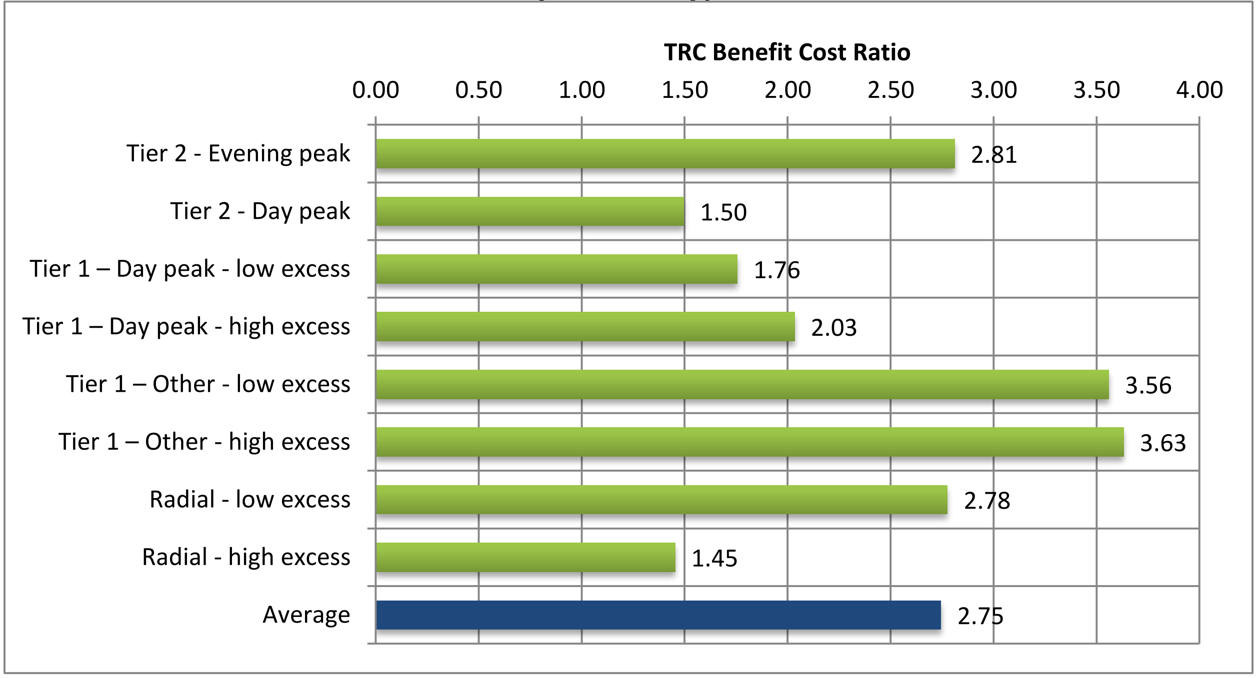
It is also quite cost effective to enroll more pledged reductions into these programs. From a TRC perspective, the benefits delivered by new participants are on average 2.75 times larger than the

[29] These include a 10-year time horizon, the CECONY Energy Efficiency Programs cost of capital of 7.72% and 3 years of historical data to support kW reductions and fixed and variable costs.

costs. Growing the program further improves its cost-effectiveness. While it may be possible to improve program efficiency, the programs are cost-effective under their current design, customer targeting and operations.

The value of DR programs varies across the eight network types. As seen earlier, the different network types have different load shapes. Some have highly concentrated peaks while other networks peak for prolonged periods. In addition, incentive payments are higher for Tier 2 networks and distribution avoided costs are lower for non-networked areas. Finally, historical performance during events differ across the eight network types. Figure 5-2 shows the TRC benefit-cost ratio associated with enrolling new customers for each of the network types.

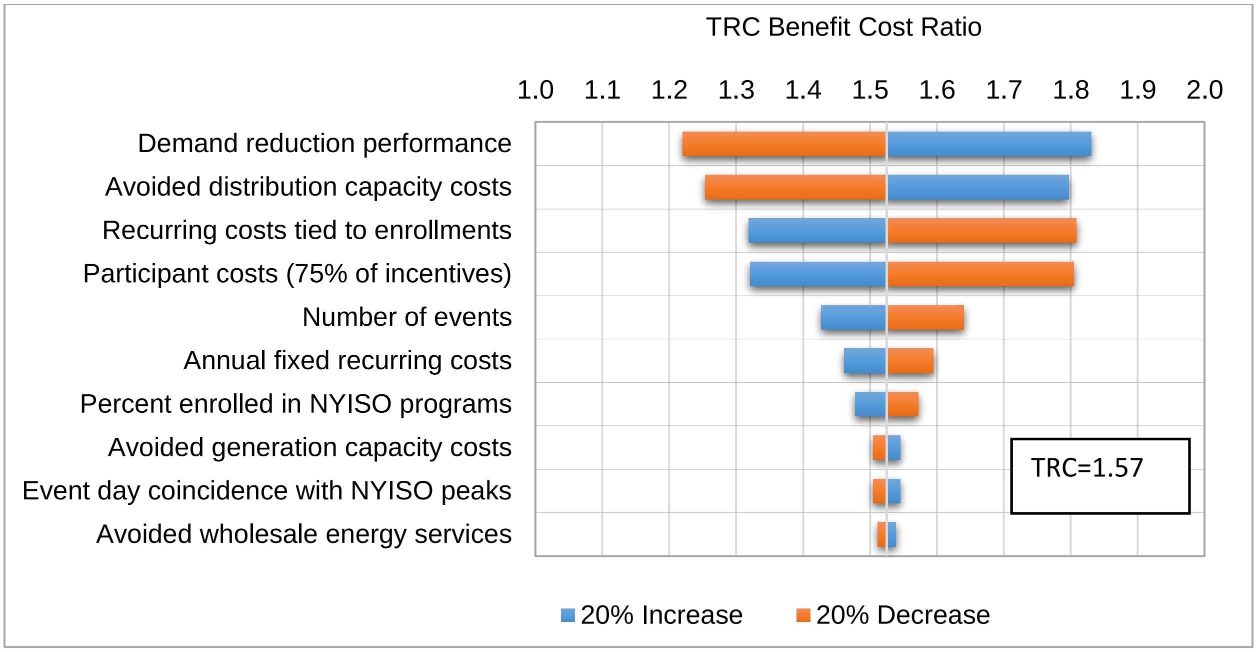
Figure 5-2: Portfolio Cost-effectiveness of New Enrollees in DLRP and CSRP by Network Type



Not surprisingly, day peaking networks and high excess radial or non-networked areas are the least cost-effective. The first have higher costs; the latter smaller benefits. We recommend some caution in interpreting cost-effectiveness by network type because avoided distribution costs are assumed to be the same for all network types because the avoided cost study did not provide separate estimates by network type. The only distinction is between areas that are networked and those that are not. In practice, the magnitude and timing of projected investments likely varies by network. Since the immediacy of investments influences the value of DR, networks with low excess capacity likely have higher benefits than those with high excess capacity. To account for these differences, avoided cost estimates specific to each network group are needed.

We also analyzed the key drivers of cost-effectiveness for the portfolio through sensitivity analysis. Each major input was changed up and down by 20%, while holding all other inputs constant. Figure 5-3 presents the sensitivity analysis of continuing DLRP and CSRP for one year without expansion. The base scenario has a TRC of 1.57. The figure shows the 10 factors that most influence portfolio cost-effectiveness. No single driver of cost-effectiveness leads to cost-ineffective results when it is changed by 20%, indicating that results are relatively robust to the inputs.

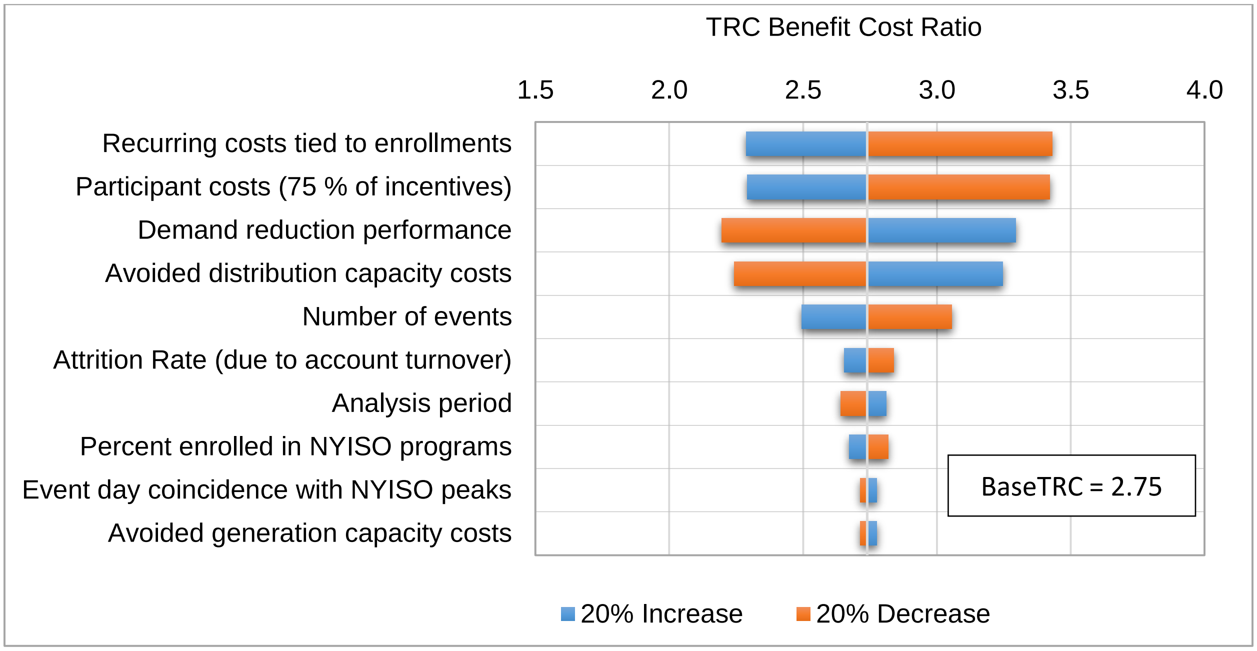
Figure 5-3: TRC Sensitivity Analysis for Continuing Operation Without Expansion



The cost-effectiveness of continuing the program without expansion is most affected by five main inputs. Not surprisingly, the results are most sensitive to demand reduction performance and avoided distribution costs. Importantly, CECONY has a limited amount of data regarding performance during events. Most customers in DLRP were dispatched only for the test event and were only required to reduce load for a single hour. In practice, customer reductions lasted well past the conclusion of the test event. CSRP performance factors were based on two five-hour events. Over time, additional events will provide more information about the reliability of performance. Two other influential factors are annual recurring costs tied to enrollment and participant costs. The TRC test assumes that participant costs for delivering DR are 75% of the incentives paid to them, which recur annually based on pledged reductions. The incentive payments are the main recurring costs tied to enrollment. For this reason, changes in either factor have a similar effect on the TRC of the programs. The assumption that participant costs equal 75% of incentive payments is not well grounded empirically, but matches the assumption used for cost-effectiveness analysis in other jurisdictions such as California. These costs are unlikely to be higher than 75%, since customers would not participate in program if their costs exceeded their incentive payments, but they may be much lower.

Figure 5-4 presents the sensitivity analysis for the TRC perspective for incremental resources in these two programs. The key drivers of cost-effectiveness for new enrollees are similar.

Figure 5-4: TRC Sensitivity for Incremental Resources



Although the program is cost-effective overall, it can be improved. One of the more noteworthy areas for improvement is in reducing dual enrollment in CSRP and DLRP. As noted earlier, customers that account for nearly 96% of the reductions pledged into CSRP are dually enrolled in DLRP. Both programs are designed to provide load relief for distribution networks and providing customers with payments for participating in both options may be redundant. In general, DLRP historically has been dispatched more often and is very flexible. While it is dispatched for network emergencies, it can be dispatched as many times as needed, where it is needed, when it is needed, for as long as load relief is needed.

6 Cost-effectiveness Analysis for Residential and Small Business Programs

This section summarizes the cost-effectiveness analysis of CECONY's Residential and Small Business DLC programs. In times of system need, these programs are designed to reduce demand by directly controlling central air conditioners. The DLC programs are highly flexible and can be called because of high system loads or due to network specific emergencies. They can be used when and where reductions are needed, as often as needed. However, the amount of air conditioner demand, and therefore the reduction potential, varies with weather and hour of day. Participants in these programs are not otherwise enrolled in NYISO DR programs and they do not dually participate in multiple CECONY programs. The lack of overlaps allows the analysis of the cost-effectiveness to be conducted for each program independently.

As in the prior section, the cost-effectiveness analysis addresses two primary questions for each program:

- Is it cost effective to continue operation of the program without expansion? This scenario takes into account that, in many instances, equipment and recruitment costs are sunk.
- Is it cost effective to add new enrollees? This scenario addresses the question of whether adding customers increases or decreases overall program cost-effectiveness.

Both of these questions are addressed by taking into account how the programs have historically operated, factoring in historical costs, event performance, dispatch practices and program rules. An important question is whether cost-effectiveness can be improved by adjusting program rules, practices or by more effectively targeting customers. As explained in the C&I section, we also analyzed the key drivers of cost-effectiveness by varying each major component by a specific percentage, 20%, while holding all other inputs constant.

The remainder of this section presents some of the key characteristics of the programs that are relevant to cost-effectiveness such as enrollment by network type, costs, incentive payments and demand reduction performance. Next, the results and sensitivity for each program are presented separately.

6.1 Program Information Related to Cost-effectiveness

Table 6-1 shows the number of control devices installed as of the August 2013, by program and network type. The location of the control devices matters both because peaking patterns differ across the eight network types and because avoided distribution costs are different for networks than they are for radial (non-network) distribution systems. Each device is treated as an enrolled unit in order to ensure that all equipment and installation costs for the programs are captured. The distribution of devices across the network types varies by program. Roughly 70% of DLC devices are located in radial distribution areas that are not networked. This pattern occurs in part because single family homes are more likely to own central air conditioners and are predominantly located in non-networked, suburban areas. In contrast, small business DLC devices are less likely to be located in radial distribution areas. In total, 21% (14% and 7%, respectively) of small business DLC devices are located in radial distribution areas.

Table 6-1: Control Devices by Network, Program and Option

Network Type	Residential DLC	%	Small Business DLC	%
Tier 2 - Day peak	1,141	4%	1,278	16%
Tier 2 - Evening peak	2,629	10%	1,108	14%
Tier 1 – Day peak, low excess	13	0%	108	1%
Tier 1 – Day peak, high excess	36	0%	29	0%
Tier 1 – Other, low excess	1,234	5%	1,967	24%
Tier 1 – Other, high excess	2,595	10%	2,012	25%
Radial - low excess	13,664	51%	1,112	14%
Radial - high excess	5,301	20%	552	7%
TOTAL	**26,612**	**100%**	**8,165**	**100%**

Another key factor that affects cost-effectiveness is retention rates, which influence the number of active devices and the magnitude of reductions in future years. Retention rate is particularly relevant for programs that require extensive efforts to enroll resources and those that involve installation of equipment. The default enrollment settings play a substantial role in the benefit lifecycle. For example, some utilities consider devices stranded if a customer moves and the new resident is not enrolled in the program. At these utilities, the default enrollment setting for new residents is non-participation. In contrast, customers that move into locations with installed load control devices in CECONY's Residential and Small Business DLC programs are defaulted onto the program if their site received a free thermostat. These customers have the option to de-enroll at any time, adjust their thermostat settings or opt-out of control conditions on an event-by-event basis. They also have the ability to remotely control their thermostat settings via internet or a phone app. As a result, de-enrollment rates for Residential and Small Business DLC are 1% and 3%, respectively. This leaves few devices stranded and enables CECONY to capture benefits over the 10-year expected useful life of the thermostats.

Table 6-2 summarizes the performance of the DLC programs during event periods in 2011–2012, by network type. The table includes the maximum reduction during event conditions, the average reduction across the event, and the coincidence adjusted value (which factors in the coincidence of reductions with network peaking risk), any program dispatch limitations, and load increases in post-event hours. The process and steps for adjusting the performance value to account for program limitations and for the coincidence with network and NYISO system peaking conditions were described in Section 4.3. The data sources and steps used to estimate the standardized demand reductions are described more fully in Appendix F.

Residential air conditioner loads tend to peak in the evening hours. Reductions during those hours can be quite high, well in excess of 1 kW per device, because air conditioner demand exceeds 3 kW and reductions are roughly 35%. This can be seen in Figure 4-9 presented earlier. However, many of the network types peak earlier in the day when residential air conditioner demand is substantially lower due to occupancy patterns. In contrast, small business reductions are generally more coincident with day-peaking networks.

Table 6-2: Demand Reductions per Device

Program	Network Type	Max. Event Reduction (kW)	Avg. Event Reduction (kW)	Adjusted for Coincidence (kW)
Residential DLC	Tier 2 – Day peak	1.14	0.73	0.75
	Tier 2 – Evening peak	1.59	1.23	0.95
	Tier 1 – Day peak – high excess	1.14	0.70	0.68
	Tier 1 – Day peak – low excess	1.14	0.70	0.69
	Tier 1 – Other – high excess	1.14	0.73	0.73
	Tier 1 – Other – low excess	1.14	0.73	0.74
	Radial – high excess	1.14	0.73	0.85
	Radial – low excess	1.59	1.23	0.90
Small Business DLC	Tier 2 – Day peak	1.07	0.79	0.65
	Tier 2 – Evening peak	0.97	0.71	0.51
	Tier 1 – Day peak – high excess	0.97	0.78	0.69
	Tier 1 – Day peak – low excess	0.97	0.78	0.73
	Tier 1 – Other – high excess	1.07	0.79	0.63
	Tier 1 – Other – low excess	1.07	0.79	0.64
	Radial – high excess	1.07	0.79	0.74
	Radial – low excess	1.07	0.79	0.69

[1] Based on reductions during days that met peak shaving criteria.

[2] Residential DLC and Small Business DLC assume an eight-hour activation (for extreme conditions) and activation start times that vary by network type based on networks load shape and concentration of peaking conditions.

6.2 Residential DLC Cost-effectiveness

Figure 6-1 summarizes the cost-effectiveness of the residential DLC program. The data sources and assumptions are documented in Appendices H and I. At a high level, it is assumed that the costs, incentives and the participant mix are similar to those in 2012. Another key assumption is that the most relevant reductions are those available for peaking conditions. These reductions are discussed in more detail in Appendix F.

Continuing the program without expansion is marginally cost-effective across all tests. Benefits from existing customers are sufficiently high to offset the approximately $2.5 million in annual overhead costs associated with continuing program operations. This scenario assumes the program continues for an additional eight years in order to recover the benefits associated with the initial upfront investment of equipment and installation costs. The decision to include eight years was based on two factors. First, the DLC program requires a significant upfront cost in the form of equipment and installation costs. Once sunk, these costs are recovered over the useful life of the device. The second consideration was that most devices at participant sites do not have a full 10 years of remaining useful life, although, on average, devices are relatively new.

Increasing enrollment in the program further improves cost-effectiveness. The benefits from new participants over the expected life of the device, 10 years, are 1.7 times larger than any costs associated with recruiting customers, installing devices, paying incentives, on-going operations, communication and maintenance.[30] The scenario for the average new participant assumes that their composition and location is similar to that of existing customers.

Figure 6-1: Cost-effectiveness of Residential DLC[31]

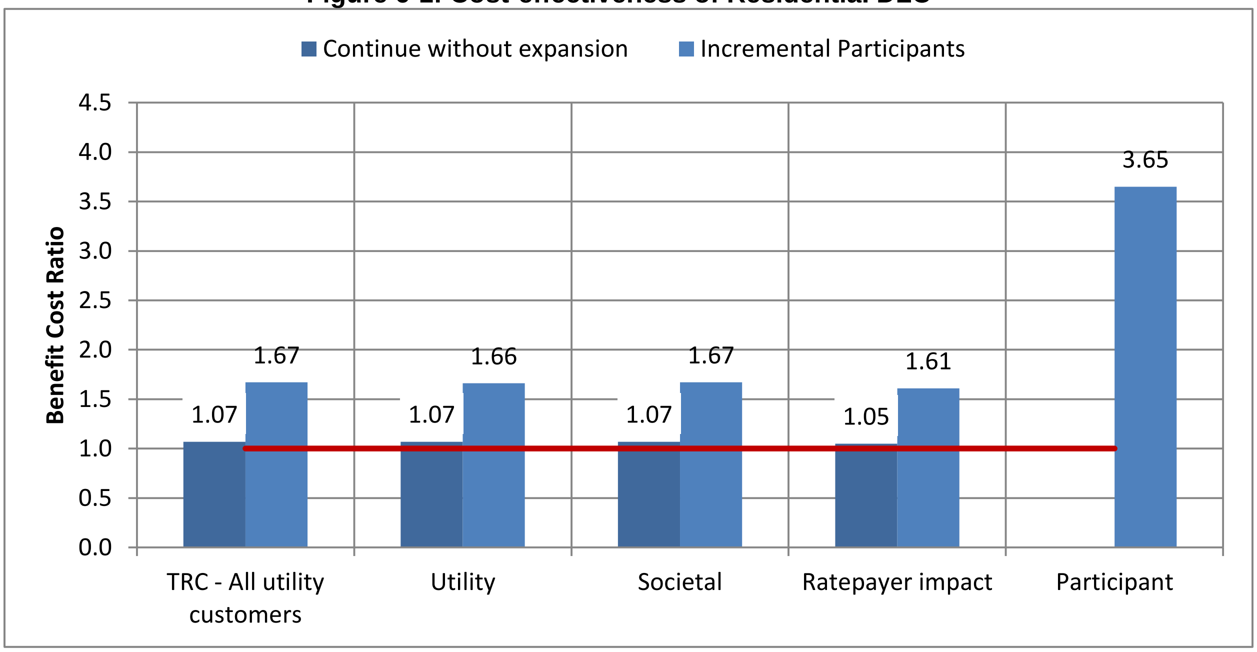


Figure 6-2 shows the cost-effectiveness of additional participants by network type. The cost-effectiveness of additional participants varies substantially based on their location. As noted earlier, roughly 70% of current participants are located on radial distribution systems, where the avoided distribution costs are lower. This high concentration of devices on the two network groups with the lowest, but still positive, benefit cost ratio leads to a weighted average TRC of 1.67. A potential step to improve program cost-effectiveness further is to redirect enrollment efforts to networks where the value of residential direct load control is greatest.

30 The results do not vary substantially based on the perspective because the main difference between the perspectives is whether incentive payments to customers are treated as a cost, transfer or benefit. For the DLC residential program, incentive payments are a small portion of program costs and consist of a one-time $25 sign up payment.

31 The Participant Cost test for existing customers is undefined. While there are benefits, participant costs are assumed to be 75% of the incentives paid to participants. Since incentives payments are limited to a first year sign-up incentive, incentive payments and participant costs for exiting customer are zero.

Figure 6-2: Cost-effectiveness of New Participants by Network Type

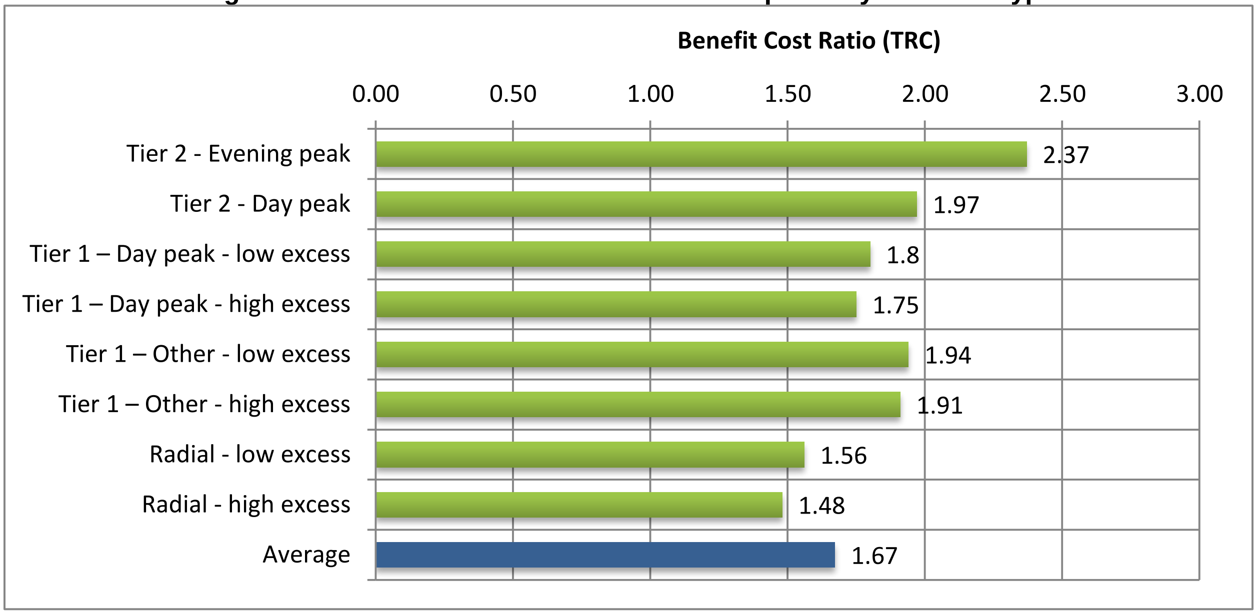


Figure 6-3 shows the key drivers of cost-effectiveness assuming no additional expansion of the program. The factor that most affects cost-effectiveness is the demand reduction per device. Reductions for existing participants can be increased by more aggressive control strategies such as increasing thermostat set points by an additional degree. However, if control strategies are too aggressive they can lead to higher event opt-out or program de-enrollment. Understanding the trade-offs between control strategy versus customer retention and satisfaction is a critical step for optimizing program design. The best way to understand these tradeoffs is to conduct systematic small scale tests. This requires randomly assigning a small subset of customers to different numbers of events and control strategies and assessing how these factors affect demand reductions, event opt-outs, customer comfort (through post-event surveys) and program de-enrollments. The second most influential factor is annual overhead costs, which total $2.5 million. While they are highly influential, reducing overhead costs can be difficult in the short run due to pre-existing contracts and process.

The other influential factors are distribution avoided capacity costs, device life, recurring costs tied to enrollment, avoided generation capacity costs and the coincidence of events with NYISO peak days. Extending the program further into the future leads to larger benefits because distribution investments in radial networks, where the majority of current participants are located, are low in the near term but larger in future years.

The program can also attain additional concrete benefits if ancillary service markets rules are modified to allow disaggregated loads such as Residential DLC to supply 10-minute spinning or non-synchronized reserves. As noted earlier, prior studies have shown that air conditioning load control can be used for grid operations, typically starting up within 60 seconds, and ramping up to 80% of capacity within 3 minutes.[32,33] Current rules do not allow resources such as air conditioner load control to cost-effectively provide reserves, even though such programs have demonstrated the two defining characteristics of operating reserves: fast start-up and the ability to ramp up to full resource capability in less than 10 minutes. The main barrier is that current rules require telemetry for each individual site (versus a sample) and do not allow for smaller distributed resources to be aggregated.

Figure 6-3: Sensitivity Analysis for Continuing Residential DLC Without Expansion

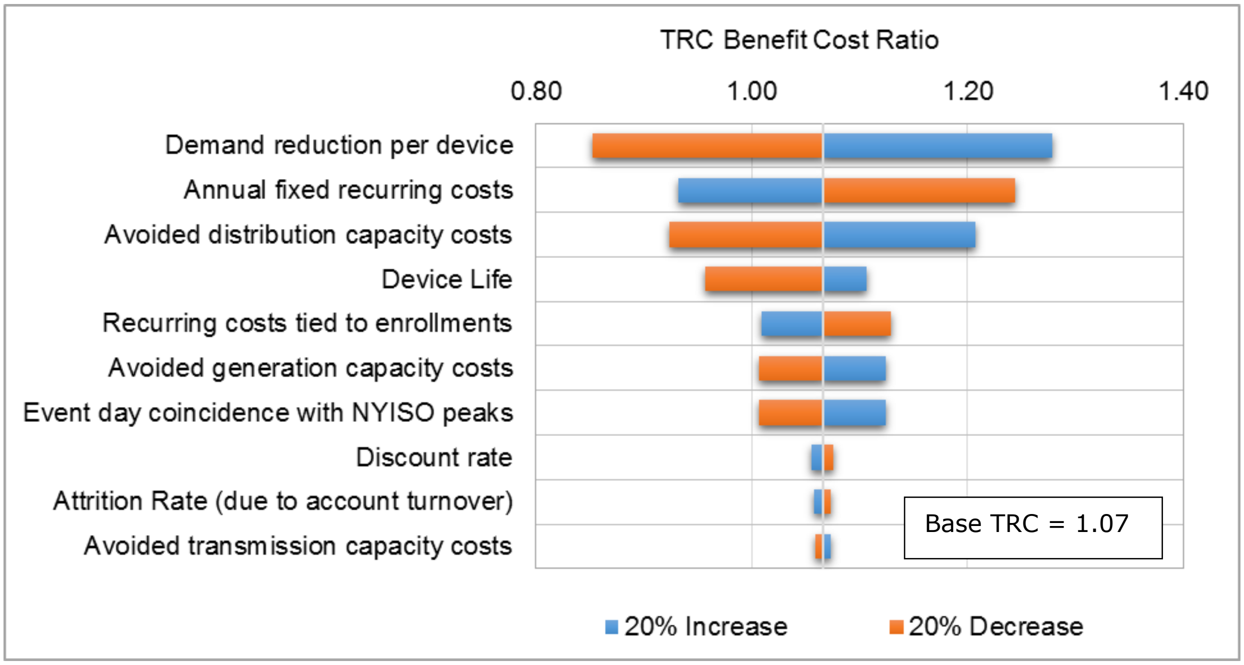


Figure 6-4 ranks the key drivers of cost-effectiveness for new participants. The most influential factor is demand reductions per device. Reductions for new participants can be increased through targeting. Not all customers use air conditioning during the critical hours when reductions are needed most. Many studies on air conditioner use conducted for other utilities show a large amount of diversity in air conditioner use during peak periods, with a large share of customers using little or no air conditioning during system peak hours. These differences arise because of varying occupancy patterns and customer preferences. A key goal is to develop ways to identify customers that use air conditioners when demand reductions are most valuable and target them for enrollment, while at the same time avoiding, to the extent possible, enrolling customers that do not use much air conditioning when reductions are most needed.

The device life and avoided distribution capacity costs are also key drivers of cost-effectiveness. The next largest driver of cost-effectiveness – one-time costs tied to enrollment – is unique to new

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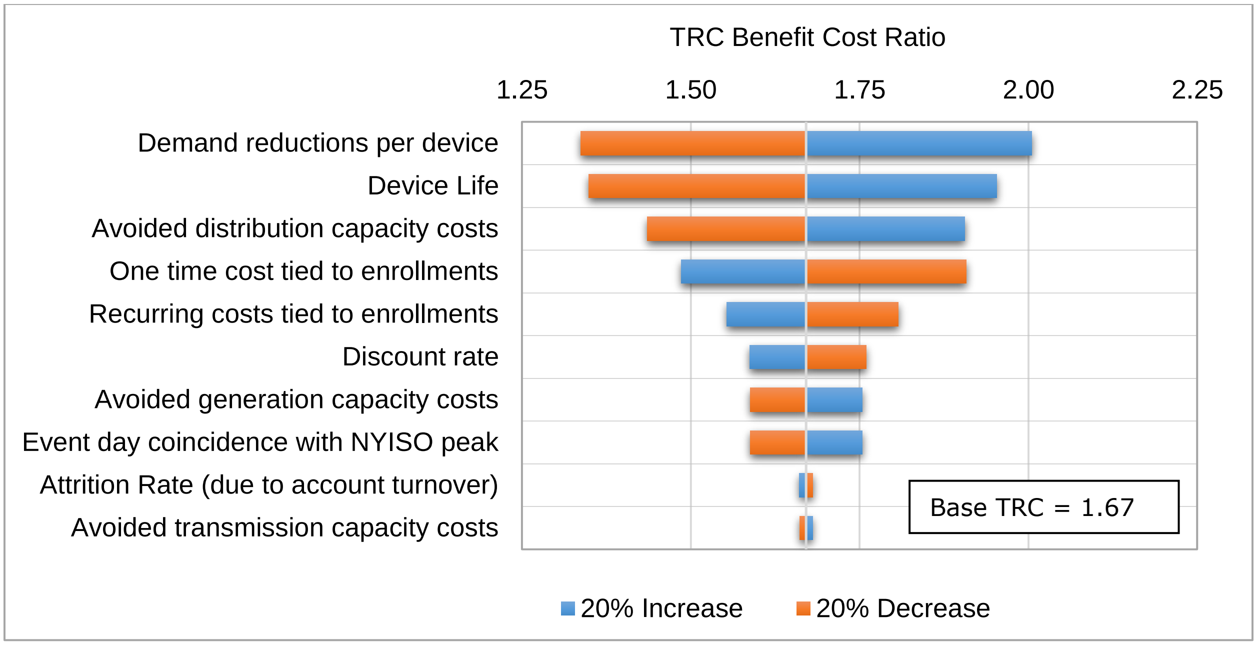
32 Sullivan, Bode, Kellow and Woehleke (2013). *Using Residential AC Load Control in Grid Operations: PG&E's Ancillary Service Pilot.* IEEE Smart Grid Transactions. Volume 99. pp. 1-9.

33 Bode, Sullivan, Berghman and Eto (2013). *Incorporating Residential AC Load Control into Ancillary Service Markets: Measurement and Settlement.* Energy Policy. *Volume 56, May 2013, pp. 175–185.*

participants. These costs include participant recruitment, installation and equipment costs, as well as the one time incentive payment.

Figure 6-4: Sensitivity Analysis of Residential DLC New Participants

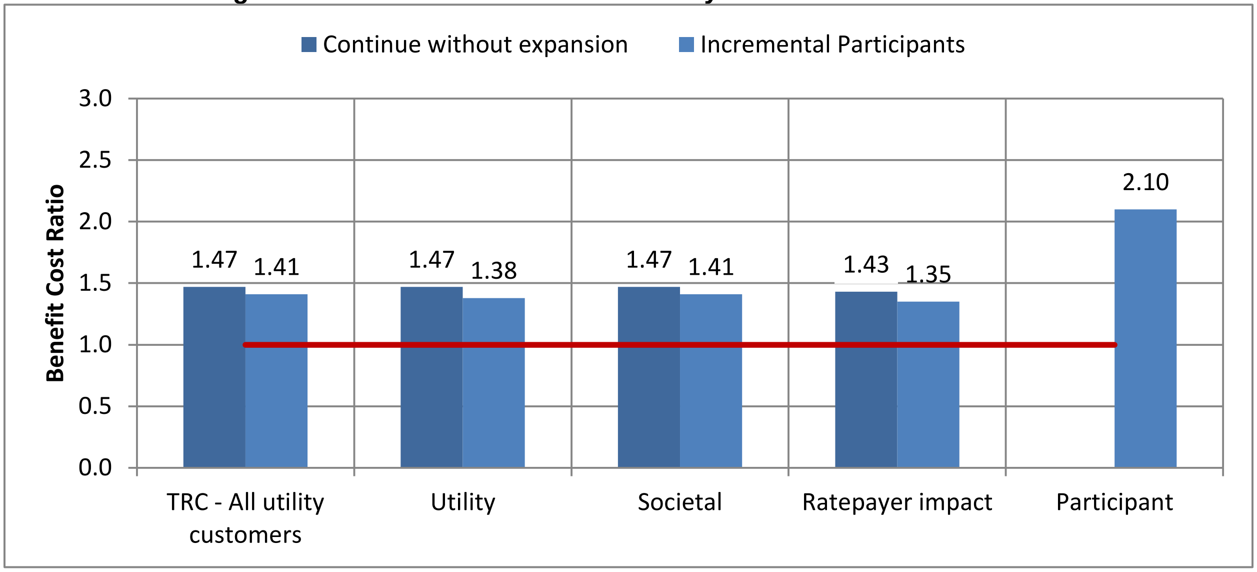


There are three main findings from the analysis of the residential DLC program. First, it is cost-effective to continue the program given its current design, targeting of customers and operating procedures. Second, adding additional participants improves program cost-effectiveness. Benefits from new participants more than offset the costs associated with them without contributing to a substantial amount of additional overhead costs. Third, while cost-effective, the program can be improved by targeting recruitment efforts at network types where residential air conditioner demand reductions are most valuable and by developing predictive models to identify customers that use air conditioning when reductions are most valuable. In other words, a key purpose of targeting is to avoid units that are rarely on when reductions are most needed and that as a result deliver no or small demand reductions.

6.3 Small Business DLC Cost-effectiveness

Figure 6-5 summarizes the cost-effectiveness of the small business component of the DLC program, which accounts for approximately 23% of all DLC devices. Continuing the program without expansion and adding new participants are both cost-effective options across all tests. Benefits from existing customers are sufficiently high to offset the approximately $0.47 million in annual overhead costs associated with continuing operations for the program. This scenario assumes the program continues for an additional eight years to recover the benefits associated with the initial upfront investment in the form of equipment and installation costs.

Figure 6-5: Cost-effectiveness Summary for Small Business DLC[34]



Increasing enrollment in the program further improves cost-effectiveness. The benefits from new participants over the expected life of the device, 10 years, are 1.41 times larger than any costs associated with recruiting customers, installing devices, paying incentives, on-going operations, communication and maintenance. The scenario for the average new participant assumes that their composition and location is similar to that of existing customers.

Figure 6-6 shows the cost-effectiveness of additional participants by network type. The cost-effectiveness of additional participants does not vary by location as much as it does for residential customers. As noted earlier, roughly 80% of current participants are located in networks, where the avoided distribution costs are higher.

[34] The Participant Cost test for existing customers is undefined. While there are benefits, participant costs are assumed to be 75% of the incentives paid to participants. Since incentives payments are limited to a first year sign-up incentive, incentive payments and participant costs for exiting customer are zero.

Figure 6-6: Cost-effectiveness of New Small Business DLC Participants by Network Type

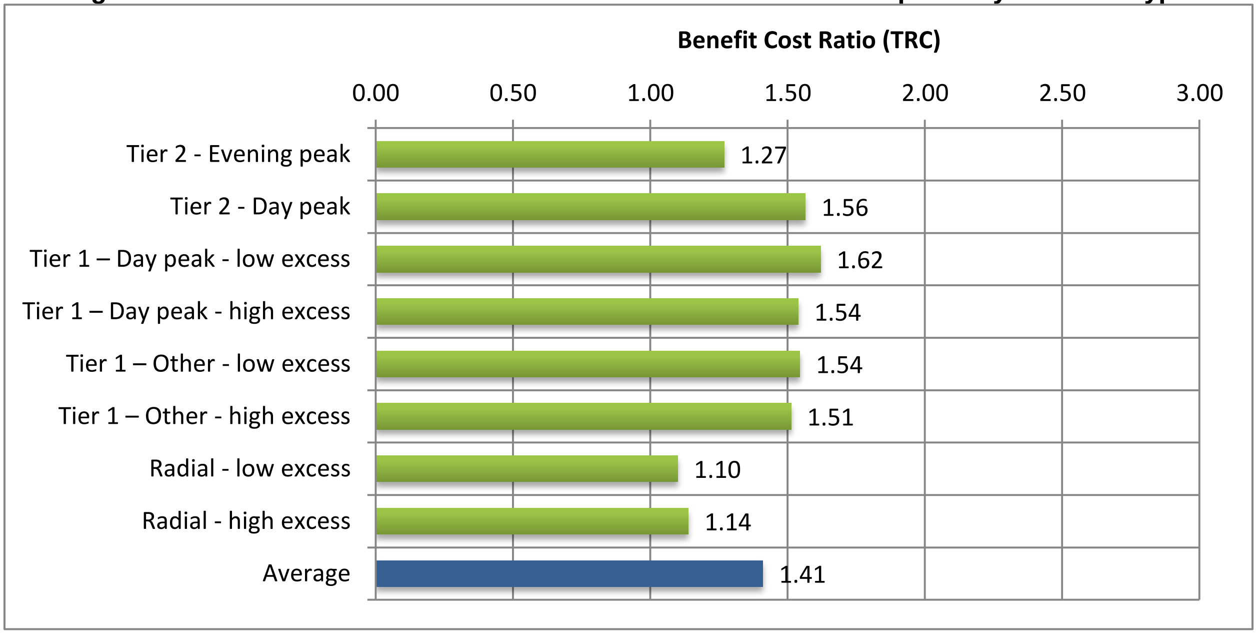


Figure 6-7 shows the key drivers of cost-effectiveness assuming no additional expansion of the Small Business DLC program. They are quite similar to the key drivers of residential DLC cost-effectiveness.

Figure 6-7: Sensitivity Analysis for Continuing Small Business DLC Without Expansion

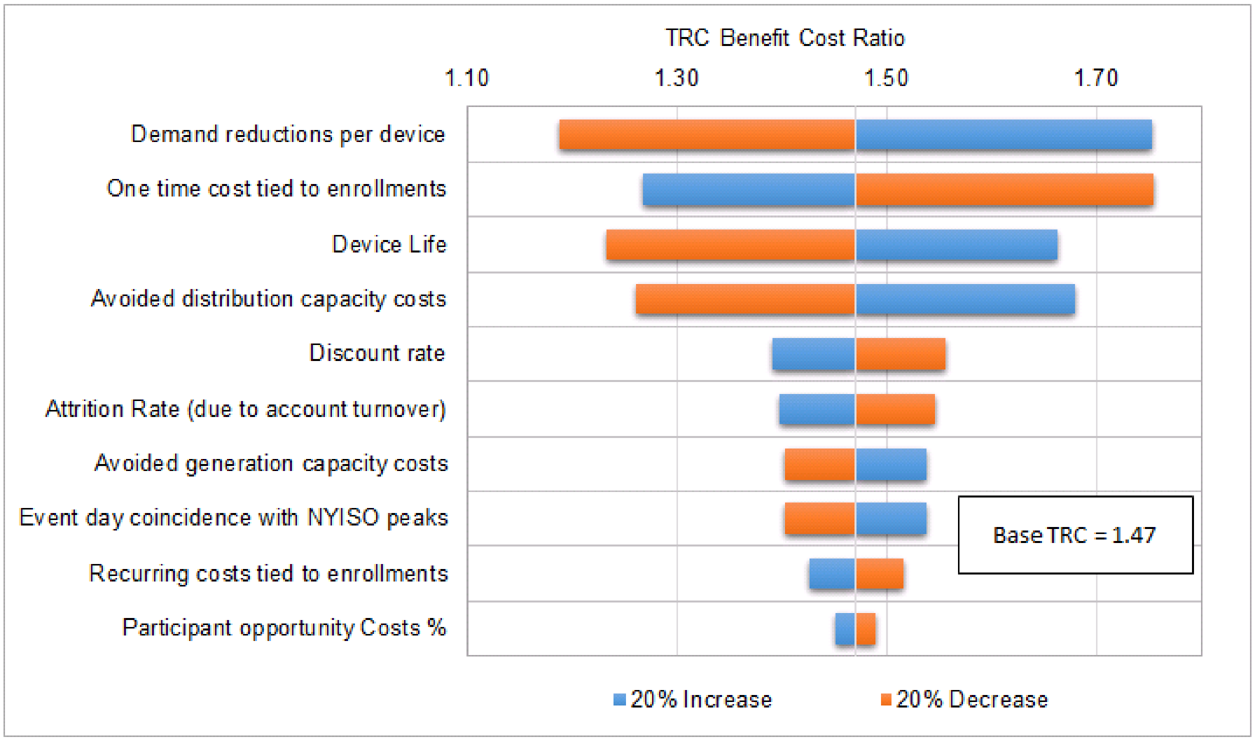


Figure 6-8: Sensitivity Analysis of New Small Business DLC Participants

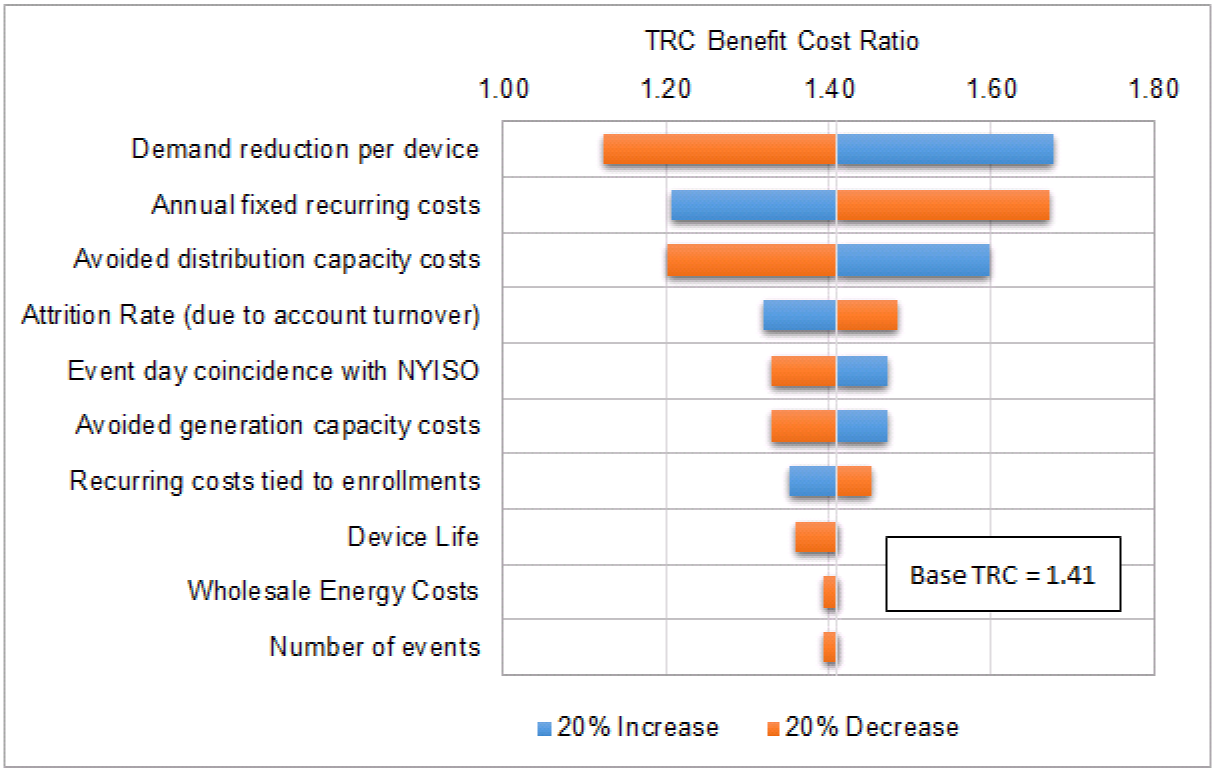


Figure 6-8 ranks the key drivers of cost-effectiveness for new Small Business DLC participants. The most influential factors also align with the residential DLC results. As a result, the main recommendation is similar: target customers who use air conditioners when reductions are most valuable.

The main conclusions for the Small Business DLC program area are similar to the findings for Residential DLC. It is cost-effective to continue the program given its current design, targeting of customers and operating procedures. Adding additional participants improves cost-effectiveness because the benefits of new participants cover the costs of adding them without significant additional fixed overhead costs. Finally, the program can be improved further by identifying customers that use air conditioning when reductions are most valuable and targeting them for enrollment.

7 CoolNYC Pilot Cost-effectiveness

Room air conditioners are one of the most significant plug loads in homes but until recently the technology to control them remotely was not available. There are over six million room air conditioners in CECONY's service territory representing approximately 2,500 MW of peak load. CECONY forecasts suggest that as many as one million room air conditioning units will be installed over the next five years. In addition, a large share of room air conditioners recruited into the pilot are located on networks, where the value of avoiding distribution capacity costs is highest.

CoolNYC is a pilot, not a program, designed to test if room air conditioners can be remotely controlled and to estimate demand reductions resulting from such control. The first phase of the pilot was essentially a technology test. The goal of the second phase, which is ongoing, is to learn what program rules and deployment strategies work best to optimize the design. Since there is no precedent for room air conditioner load control programs, there is limited information about what works and what does not. It is important to recognize that a substantial amount of innovation is taking place as part of the CoolNYC pilot and that important questions about room air conditioner load control are still being addressed.

The purpose of applying the cost-effectiveness tool to CoolNYC is not to assess cost-effectiveness of the pilot, but to better understand what it would take to make control of room air conditioners cost-effective given what is known. Any conclusions about whether or not room air conditioner control can be cost-effective will evolve based on ongoing pilot tests about changes in technology costs.

Room air conditioners typically have smaller capacities compared with central air conditioners. Consequently, cost-effectiveness is highly sensitive to technology device costs and the magnitude and timing of room air conditioner usage relative to peaking conditions at the local level. Figure 7-1 shows the estimated energy use per room air conditioner during 2013 event days, based on a control group that did not experience curtailments. Even on the most extreme day, room air conditioner loads, on average, did not exceed 0.6 kW. While a room air conditioner may be turned on, it draws power only when it needs to cool down the room to meet the temperature setting. The hourly consumption is a function of the share of each hour that the unit is operating which, in turn, is affected by the target temperature setting, outside temperatures, unit size, occupancy patterns, and customer preferences.

Figure 7-1: Room Air Conditioner Demand During 2013 Event Days – Control Group

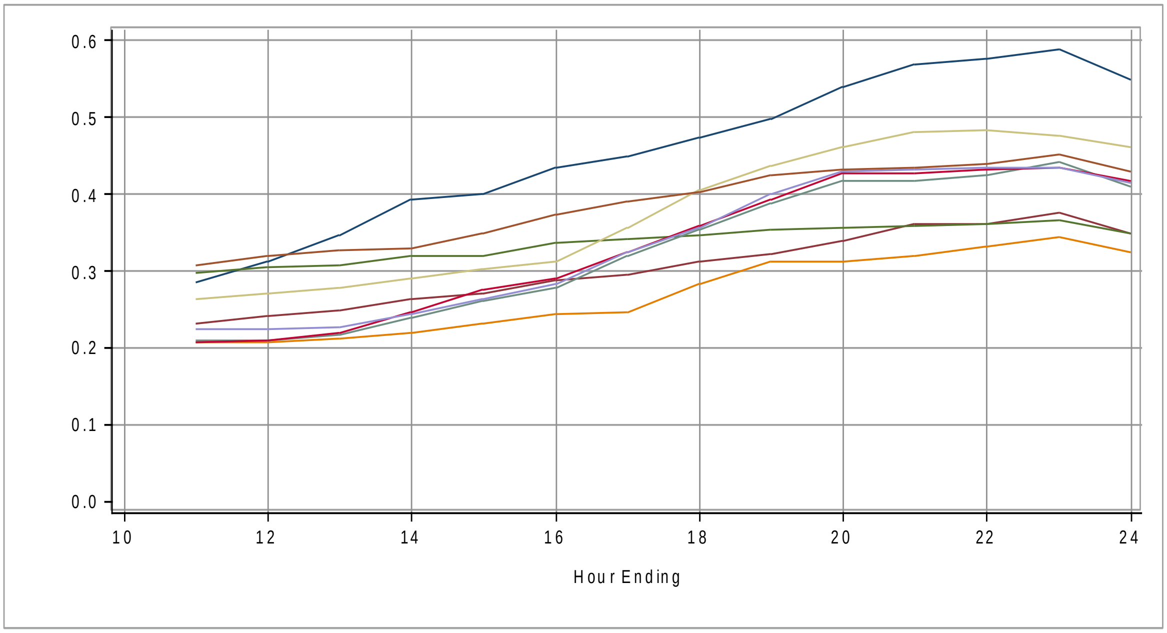
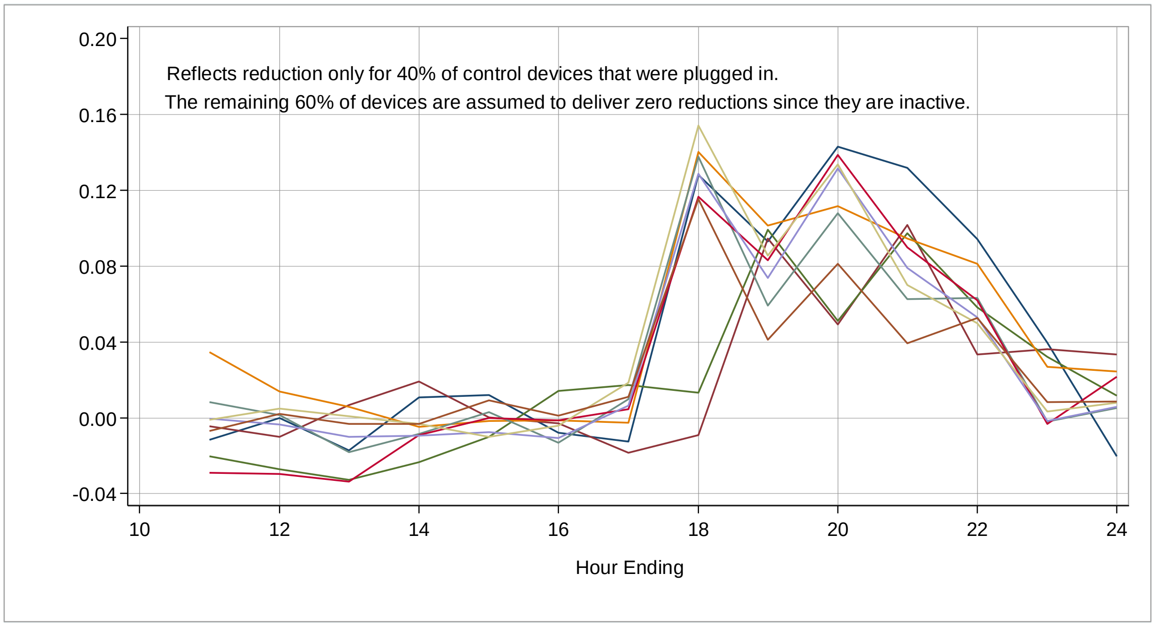


Figure 7-2 shows the estimated hourly reductions for the same set of customers and event days presented in Figure 7-1. It only includes devices that were plugged in and could be controlled. While the devices were plugged in, the room air conditioners were not necessarily running during the event period. On average, the control technology reduces room air conditioner demand by 22% for the 40% of customers that plugged in the devices. The average reduction during the curtailment periods was 0.09 kW per plugged in device. However, because only 40% of devices were plugged in, the reduction per device mailed to participants is lower, less than 0.04 kW per device (40% x 0.09 kW).

Figure 7-2: Room Air Conditioner Reductions During 2013 Event Days



In light of the small reductions, several key questions arise:

- What would it take for benefits from the technology to exceed costs?
- Is the installation of devices cost-effective if it also leads to energy savings?
- Assuming not all room air conditioning units are cost-effective to install, what share are in fact cost-effective to install?
- How many room air conditioners would have to be enrolled to cover overhead costs associated with running the program?

We cannot concretely answer these questions because of limited empirical data on key factors such as energy savings associated with the CoolNYC technology and variation in room AC use across the New York City population. However, we present a set of concrete scenarios to better understand what steps can be undertaken to make a residential room air conditioner control program cost-effective. We also discuss the additional empirical research needed to understand the cost-effective market potential.

The following four scenarios were analyzed:

1. *Base case.* This scenario assumes that there are 2.5 room air conditioners on average per household and that loads and load reductions are equal to those observed in the 2013 pilot. The plug in or installation rates are assumed to be 80% and annual attrition is set at 10%. The scenario assumes participants are paid a $25 sign up incentive per household and a $10 annual recurring incentive per household. Acquisition costs are assumed to be $30 per household and device equipment and installation costs are assumed to be $115 per device, both of which are based on 2012 pilot costs.
2. *Base case + lower equipment costs.* This scenario is similar to the first, except it assumes that equipment and installation costs are 20% lower, $92 per device rather than $115 per device. Lower equipment costs are feasible for two reasons. First, new technology costs tend to fall as manufacturers refine the design, lower productions costs and face competitions from other manufacturers. Second, most load control device manufacturers engage in volume pricing, reducing the price per device for larger orders. Device equipment costs will likely be lower for a program than for a pilot based on volume alone.
3. *Base case + lower equipment costs + larger reductions.* This scenario is similar to the prior one except that it assumes larger reductions from a combination of two steps. The first is identifying and targeting customers that use room air conditioner when reductions are most valuable. The goal is to target customers who use room AC twice as much as ones currently in the pilot. This can be accomplished by identifying larger room air conditioners and customers who use room air conditioners during network peaking conditions. The second step is to employ more aggressive control strategies to increase the percent of demand reductions from 22% to somewhere between 30-40%, which is similar to the percent reductions for central air conditioners. The net effect of these steps is to triple the load reduction per device.
4. *Base case + lower equipment costs + larger reductions + energy savings.* This scenario is similar to the prior one except that it assumes energy savings of 50 kWh during non-event days. This value is an assumption and energy savings during non-event days would need to be demonstrated empirically. Energy savings of 50 kWh amount to roughly 5% of energy use per room air conditioner unit, with the savings largely following room air conditioner patterns.

These scenarios ignore the annual overhead costs of approximately $585,000 and instead focus on the marginal cost-effectiveness of additional participants. For each scenario, benefits and costs were analyzed over the expected useful life of devices, 10 years. Once additional participants provide net benefits, FSC can calculate the number of participants needed to break even and cover $585,000 in annual over-head costs.

Table 7-1: CoolNYC Additional Participant Scenarios

Scenario		NPV Benefits per device	NPV Cost per Device	Net Benefits per Device	Benefit Cost Ratio	Break-even additional participants
1	Base case	$71.22	$158.88	-$87.67	0.45	N/A
2	*Base case + lower equipment costs.*	$71.22	$135.40	-$64.18	0.53	N/A
3	*Base case + lower equipment costs + larger reductions*	$213.65	$135.40	$78.25	1.58	56,400
4	*Base case + lower equipment costs + larger reductions + energy savings*	$214.68	$135.40	$79.28	1.59	55,600

To make the program cost-effective, substantial effort will need to be devoted to identifying customers that run room air conditioner units when reductions are most needed. More aggressive control strategies will also be required. Based on the third scenario, net benefits are roughly $78 per device. A total of roughly 60,000 additional devices would need to be deployed in a cost-effective manner for the program to cover overhead fixed costs. Any additional cost-effective enrollments in excess of 60,000 would help improve the program's cost-effectiveness. Calibrating the program so it runs more efficiently may take an additional year or two since improved targeting efforts and more aggressive control operation requires some time to test and learn what does and does not work.

8 Conclusions and Recommendations

The cost-effectiveness model and framework developed through this project represents an improvement over the prior model that Con Edison used to measure cost-effectiveness of demand response. The prior model did not time-differentiate value, did not account for the fact that reductions from some DR resources vary by hour of day, did not asses the coincidence of DR reductions and load shifting with local or system peaking conditions, and did not account for the fact that DR characteristics such as availability and maximum event duration affect value. It also assumed that the value of DR was similar across all of CECONY's distribution areas despite the diversity in load shapes and peak periods. Finally, the prior model did not account for participant and aggregator costs for delivering DR, which are typically unobservable since they must take into account lost business or production, impacts on comfort, transaction costs, and other factors.

A central tenant of the new framework is that different DR programs have different characteristics and their value depends on several factors, including, how well DR resources coincide with system and local peaks, performance during reduction events, limits on availability, and limits on maximum event duration. Another tenant of the new framework is that the value of DR resources for distribution systems depends on the characteristics of the distribution area in which the resources are available. As part of this effort, CECONY's 83 distinct distribution areas were categorized into eight network groups based on network/non-network status, load shapes, amount of excess capacity and network reliability index (NRI) scores. The cost-effectiveness model allows users to input different demand reductions, enrollment levels, incentives, costs and benefits for each of the 8 network groups.

The application of the cost-effectiveness framework produced several key findings regarding CECONY's programs and pilots, which are summarized below. However the most important application of the model is using it to determine how programs can be improved by adjusting program rules, more effectively targeting customers or changing operation practices. In other words, the model can help assess how program changes affect cost-effectiveness rather than simply modelling programs as currently configured. Cost-effectiveness analysis is not simply a conceptual exercise or done for reporting purposes only. When done correctly, it allows for comparison of resource options, provides factual insights, makes tradeoffs transparent, improves the planning process and helps maximize value. The sensitivity analysis presented as part of this report helps identify program design characteristics that contribute most to the value delivered by DR, which is a first step in optimizing programs.

8.1 Key Program Findings

The analysis presented here revealed several key findings concerning CECONY'S existing DR programs, including:

- CECONY's DR programs are cost-effective as currently designed, marketed and operated.
- Adding new participants improves the cost-effectiveness of large customer programs and the residential and small business DLC programs. Benefits from new participants more than offset their variable costs without contributing to a substantial amount of additional overhead.
- The cost-effectiveness results are robust – that is, the programs are cost-effective from multiple perspectives and the results do not change from positive to negative when any of the major inputs are adjusted upward or downward by 20%.

- Cost-effectiveness of the programs can be improved by targeting recruitment efforts at networks where reductions are most valuable and by reducing redundancies associated with dual enrollment.

Key findings associated with the CoolNYC pilot include the following:

- Room air conditioning load control has significant DR potential given the large number of room air conditioners used in New York City. However, as currently configured, the average demand reduction obtained from room air conditioners in the CoolNYC pilot is too small, 0.087 kW per plugged device, and the percent of control devices sent to consumers that are actually plugged in (40%) is too low, to create sufficient benefits to offset equipment costs and incentive payments.
- Scenario analysis shows that the CoolNYC pilot has the potential to identify cost-effective deployment strategies for control of room air conditioners. It will be critical to experiment and adjust targeting, event operations, delivery channels, program rules, incentive structures and, potentially, technology to identify how to optimize the design of load control for room air conditioners.

8.2 Recommendations

- The input values used for avoided transmission and distribution costs in the analysis presented here have distinct values for networked and non-networked areas, but do not vary with network characteristics. In reality, avoided costs would value with network characteristics and developing cost estimates that reflect this variation would allow for refinements in the analysis and potential improvements in targeting, program operations and cost-effectiveness. CECONY should consider developing avoided cost values that reflect this variation.
- Further explore additional benefits of DR. Three potential benefits with tangible effects in CECONY's territory are: avoided disruption costs associated with transmission and distribution upgrades (a societal benefit); using DR modularity to gain more certainty about load growth forecasts; and improvements in reliability by smoothing out changes in reliability due to the lumpiness of distribution investments.
- Concentrate future DR resources in networks with the most value or those where reducing demand for a limited number of hours leads to largest reduction in peak demand. These networks are identified in Appendix D.
- Expand the programs and fully incorporate them into planning. As currently designed adding participants is highly cost-effective and increases the cost-effectiveness of the program. Expanding the magnitude of the program also helps ensure that distribution investments are indeed avoided. To defer distribution investments, the reductions need to be sufficiently large as a percentage of a network's peak demand.
- Explore the degree to which NYISO is agreeable to adjusting ancillary service market rules to allow direct load control to serve as contingency reserves. Ancillary services represent a valuable, untapped additional benefit stream and grid service with minimal effect on CECONY's ability to use it for distribution relief and minimal effect on participants.

Appendix A Literature Review

This document summarizes the literature on estimating the cost-effectiveness of Demand Response (DR). Cost-effectiveness analysis is a widely applied tool designed to allow direct comparison across resource options and provide a basis for prioritizing investments. The main goal is to facilitate more efficient allocation of resources by using a common metric – net benefits or benefit cost ratio – to assess alternative options. Cost-effectiveness analysis is generally applied on a forward looking basis to investments that typically have large upfront costs but have benefits that accrue over multiple years. It also requires a pre-specified perspective (e.g., societal, utility, etc.), since two different parties can view the same outcome differently. In general, cost benefit frameworks must address three fundamental questions: What is the analysis perspective? Are the benefits and costs properly identified and classified? And, are cost and benefits properly valued?

As this literature review demonstrates, there has been relatively little debate about the first two questions. Instead, most discussion has been about the third question, which this review focuses on. In particular, there are two aspects of this question that are of particular importance for this project: 1) How do the DR program and system characteristics affect the magnitude of costs and benefits? and 2) What is the appropriate way to incorporate transmission and distribution benefits into the evaluation? These topics are covered in detail in sections 3 and 4 of the literature review.

FERC's *2010 National Action Plan on Demand Response*[35] and its 2*012 Assessment of Demand Response and Advanced Metering*[36] both acknowledged that a key barrier to DR has been the lack of suitable cost-effectiveness tools. In 2012, FERC organized a working group of experts to develop a framework for evaluating the cost-effectiveness of DR resources. The subsequent report identified several topics where there remains a substantial amount of debate (Woolf 2012).[37] Most of the debate about DR cost-effectiveness analysis has centered on how to factor unique aspects of DR resources into the valuation process. The debate is less about whether the cost-effectiveness framework identifies the right benefit and cost categories and more about whether DR value and costs are quantified correctly. As the report by the National Action Plan Cost-Effectiveness Working group states:

> "There is general agreement that different types of demand response resources have different characteristics, and therefore adjustments should be made to the amounts and types of capacity avoided through demand response programs based on the availability and exhaustibility of the demand resources, limits on event duration or number of hours the demand resource can be dispatched, and amount of advance notification required. The capacity avoided, in other words, very much depends upon the specific characteristics of the

[35] Available at: http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf

[36] Available at: http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

[37] FERC. 2013. *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Cost-effectiveness Working Group. Available at: http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-cost-effectiveness.pdf.

> demand response resources. There remains a vigorous debate, however, on how such adjustments should be made. (Woolf 2012 pp. 35)"

The remainder of the literature review is structured into three sections. First, we review DR specific cost-effectiveness frameworks and focus on those that have been adopted. The next section discusses the literature on how to incorporate characteristics of different types of DR programs into valuation. It also includes a review of how publicly available models have adjusted for unique characteristics, since several important valuation decisions are not explicitly presented in documents but are in the models themselves. We conclude by reviewing the literature on transmission and distribution benefits, which are particularly relevant for Consolidated Edison Company of New York (CECONY).

This literature review is specific to DR; it does not discuss the full history of cost-benefit analysis or the general practice of cost-benefit analysis, as there are ample resources available that cover the issues (Boardman et. al 2010, Levin 2001, Woolf 2012).

The literature review is a first step towards updating CECONY's cost-effectiveness models for DR. Additional steps have been completed or are in the process of being implemented. These include:

- Identifying how CECONY's distribution system differs from most other utilities and how it affects the value of DR in a distribution context;
- Assessing how CECONY's historical DR cost-effectiveness models compare with industry standards and identifying improvements to the models;
- Defining a framework for CECONY's cost-effectiveness analysis. This involves defining the costs and benefits; defining how to value DR resources given unique operational characteristics; accounting for the fact that avoided distribution cost may vary for different networks; and other key decisions;
- Defining overlaps and gaps between CECONYs and NYISO's programs to ensure benefits are neither double counted or ignored in the valuation framework;
- Developing a model that is functional and flexible; and
- Estimating the cost-effectiveness of each of CECONY's DR programs and providing recommendations as to how to improve cost-effectiveness.

A.1 Proposed and Adopted Demand Response Specific Benefit Cost Frameworks

In the past decade there have been a number of efforts to develop cost-effectiveness frameworks specific to DR. There also has been a substantial amount of activity in the United States regarding the cost-effectiveness of smart grid programs, which overlaps somewhat with DR. Our literature review focuses on initiatives aimed at developing cost-effectiveness frameworks and less so on general discussions about the benefits and costs of demand response. We first document the efforts at developing DR cost-effectiveness guidelines or frameworks, next we compare the frameworks that have been explicitly adopted and how they categorized different costs and benefits depending on the perspective adopted.

A.1.1 Initiatives to Develop Demand Response Specific Cost-effectiveness Frameworks

Efforts to develop DR specific cost-effectiveness frameworks and tools date back to 2005. Prior to that time period, most cost-effectiveness analyses relied on California's Standard Practice Manual (CPUC 2002) and applied tools developed for energy efficiency to demand response programs. Prior to 2005, some attempts had been made at valuing the effect of demand response on wholesale market prices but most of these efforts were targeted at specific value streams rather than comprehensive frameworks.

The Energy Policy Act of 2005 (EPACT) prompted a series of efforts aimed at quantifying demand response benefits. It explicitly required the U.S. Department of Energy (DOE) to issue a report identifying and quantifying the national benefits of demand response and to make a recommendation on achieving specific levels of such benefits. The DOE report to Congress (DOE 2006) identified benefits of demand response but it did not quantify the national benefits. At the time, the report authors found that:

> "To date there is little consistency in demand response quantification. Three types of studies have looked at demand response benefits; the time horizons and categories of benefits examined vary widely... Based on this review, DOE concludes that, to date, the estimated benefits of demand response are driven primarily by the quantification method, assumptions regarding customer participation and responsiveness, and market characteristics. Without accepted analytical methods, DOE finds that it is not possible to quantify the national benefits of demand response (pp. vi-vii)."

A key outcome of the DOE report was recognition that demand response has fundamental differences from energy efficiency and that existing cost-effectiveness frameworks needed to be adjusted and modified. Since then several attempts have been made at developing formal demand response specific cost-effectiveness frameworks.

In 2006, DOE sponsored a two-phase project with the explicit goal of valuing demand response. In the first phase, DOE selected two teams to identify gaps in demand response valuation and propose an outline for a valuation framework.[38] Based on the first phase results, the second phase objective was for DOE to select a team to proceed with development of a demand response cost-effectiveness framework and accompanying publicly available models. DOE never proceeded with the second phase and the outlines and gap analysis performed at that point in time were never converted into a formal framework. The report from the first phase of the project is publicly available but do not constitute a framework (Orans 2006).

Another effort at valuing demand response was sponsored by the International Energy Agency and started independently in 2005. The report was finalized in January 2006 (IEA 2006) and recommended using resource planning models to quantify the value of demand response. The analysis under this approach consists of running resource planning models with and without demand response resources included in the forecast while maintaining the same target level of reliability. The resource mix and costs change when demand response is introduced. Conceptually, the net benefit of demand response is the difference in the cost of operating the electricity grid with and without it. While the approach is conceptually simple, three main limitations have been documented (Woolf 2012). First, the approach reduces transparency since most resource planning models are highly complex. Second, planning models are not designed to incorporate the unique characteristics of demand response resources that do indeed affect value. Third, the planning framework approach focuses almost exclusively on generation capacity value. This framework has not been adopted or applied in practice. The team proposing the resource planning valuation framework was one of the two teams selected for the first phase of the above mentioned DOE effort.

In 2007, four additional initiatives at developing demand response specific cost-effectiveness frameworks were undertaken by the California Public Utilities Commission (CPUC), National Grid, Ontario Power Authority (OPA) and the Pacific Northwest Power Coordinating Council (NPCC):

1. The CPUC's initiative led to the adoption of the CPUC's Cost-Effectiveness Protocols in 2010 (CPUC 2010).[39] The framework was employed for the 2012-2014 demand response program applications, but, in 2012, the CPUC initiated a series of workshops to modify aspects the framework and models that were particularly controversial (CPUC 2012). An important topic that is currently being revisited is how to adjust value based on operational characteristics of demand response resources.

2. The National Grid initiative had three explicit goals that differed from other initiatives: inclusion of inputs and results with uncertainty estimates (not just point estimates); the ability to incorporate targeted transmission and distribution investments in the model; and the ability to include potential changes to the market structure in the ISO-NE's forward capacity market and its rules for ancillary service participation. This framework and model were not publicly published.[40]

[38] FSC was part of one of the teams, which included E3/FSC/LBNL/HMG.

[39] FSC developed the utility proposal for the California Load Impact Protocols, which was adopted largely unmodified by the CPUC in 2008. The impact protocols were explicitly designed to be used for cost-effectiveness and long term planning.

[40] National Grid hired FSC to develop a DR specific cost-effectiveness framework and model.

3. Another effort was launched by the Ontario Power Authority, which is responsible for coordinating conservation efforts, long term planning of the electricity system, and contracting of clean electricity resources including natural gas, nuclear and wind power. The framework report was published by OPA in 2008 and the model has been used for its cost-effectiveness reporting from 2009 onward.

4. A fourth effort was launched by NPCC to better understand the valuation of demand response and how to incorporate it into the Sixth Northwest Conservation and Electric Power Plan (NPCC 2010). The power plan, published in 2010, provides a set principles and guidelines for cost-effectiveness analysis and mirrored drafts of the California protocols.

Despite the above efforts, *FERC's 2010 National Action Plan on Demand Response (FERC 2010)* and its *2012 Assessment of Demand Response and Advanced Metering* (FERC 2012) both acknowledged that a key barrier to demand response has been the lack of suitable cost-effectiveness tools.

In 2012, as part of the National Action Plan on Demand Response, FERC organized a working group of experts to develop a framework for evaluating the cost-effectiveness of demand response resources. The framework was patterned after the 2010 California Cost-Effectiveness Protocols. It also did not provide guidance on how generation, transmission or distribution capacity value should be adjusted for operational characteristics (e.g., limits on the months, days, and/or hours in which DR program events can be called; limits on maximum duration of program events; etc.) of demand response resources. The report identified several topics that were not resolved by the California protocols and where there remains a substantial amount of debate (Woolf 2012), including how to account for demand response program constraints in valuing capacity. While the report proposed a general cost-effectiveness framework, it lacks regulatory authority. It is up to the individual states to approve cost-effectiveness models.

A few aspects from the above initiatives are noteworthy. First, none of the jurisdictions that adopted DR cost-effectiveness protocols had an organized capacity market. Second, the California, OPA and NPCC guidelines all agree that capacity benefits for a demand response resource should be adjusted for differences that reflect operational. However, neither the California nor the NPCC protocols provided guidelines for how to make those adjustments nor did they identify the characteristics that most influenced value. The OPA framework explicitly addressed how to adjust capacity value to take into account operating characteristics of different demand response resources. In 2011, Idaho Power (an NPCC member), applied the same approach used by OPA for valuing DR resources. They submitted proceedings from a two day workshop FSC put together for Idaho and Oregon regulators as a supplement to their Demand-Side Management 2011 Annual Report (Idaho Power 2012). Third, nearly all of the initiatives discussed the challenges of using DR for deferring Transmission and Distribution (T&D) investments, but did so in the context of radial distribution systems.

A.1.2 What Is the Analysis Perspective?

What counts as a cost and as a benefit depends on the perspective taken. Different cost-effectiveness tests take different perspectives. The difference between the tests is that an item might count as a benefit or cost in one test, while it might be count as a transfer from one party to another if a different perspective is adopted. This is best illustrated through the analogy of a business firm. A firm may cut back funding in one department and transfer it to another. Overall, the firm did not experience any change in its balance sheet; it simply transferred funding. However, each individual department experienced a change in funding levels.

All of the frameworks adopted emphasize three main cost-effective perspectives:[41]

- *Societal*: Do the costs to society decrease? This perspective measures the costs and benefits experienced by all members of society, including people not participating in the program. (CPUC 2010, NAPDR).
- *All utility customers*: This perspective is often referred to as the Total Resource Cost (TRC) Test. The key question is whether the costs for the average utility customer decrease. It includes the costs and benefits experienced by all utility customers, including program participants and non-participants.
- *Utility*: This perspective is often referred to as the Program Administrator Cost (PAC) or Utility Cost Test (UCT). It measures whether the resource alternative is an efficient investment from the utility standpoint.

A.1.3 Categorizing Demand Response Benefits and Costs

Table A-1 shows how the three different cost-effectiveness frameworks adopted categorized benefits and costs under each perspective. Not surprisingly, the delineation of benefit and cost categories are very similar. Both the Ontario and California frameworks were grounded on the 2001 California Standard Practice manual. The 2012 NAPDR Working Group's cost-effectiveness report followed the blueprint of 2010 CPUC protocols.

There are few noteworthy differences, however. Some are due to semantics while other differences are concrete. On the cost side, all three frameworks largely agree. The main difference between the different tests is that the utility tests include the incentives paid to customers as a cost and exclude participant costs (which are not borne by the utility). In practice, costs are typically explicitly separated into start-up costs, a one-time cost tied to enrollments (e.g., installation of direct load control equipment), recurring program costs (e.g., measurement and evaluation), and recurring costs tied to enrollment (DOE 2006).

In the documents describing the frameworks, the majority of costs are in the very broad category of administrative costs, which includes operations and maintenance costs, IT costs, communication costs, marketing costs, measurement, evaluation, verification and reporting costs. The NADPR's working group report includes additional categories for equipment costs and environmental compliance costs that are not explicitly listed in California and Ontario frameworks. The cost of environmental compliance is also placed on a separate category in the NAPDR report. In jurisdictions that allow behind-the-meter generation to participate in demand response programs, the costs of using back-up generation should be included.

41 Two additional but less critical perspectives are often quantified. The participant perspective is used to assess how attractive different programs are to potential participants. The rate payer impacts perspective assesses how the demand side programs affect revenue requirement and rates. This perspective counts participant incentives as a costs and does not factor in that some or all of the incentives are transferred to a subset of customers who participate in programs.

Table A-1: Costs and Benefits by Test and Source

Category	NAPDR			CPUC 2010 Protocols			OPA Framework		
	Societal	TRC	PAC	Societal	TRC	PAC	Societal	TRC	PAC
Cost									
Program Administrator Expenses	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Program Administrator Capital Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Financial Incentive to Participant *	--	--	Yes	--	--	Yes	--	--	Yes
DR Equipment Cost: Utility	Yes	Yes	Yes						
DR Equipment Cost: Participants	Yes	Yes	--						
Participant Transaction Costs	Yes	Yes	--	Yes	Yes	--	Yes	Yes	--
Participant Value of Lost Service *	Yes	Yes	--	Yes	Yes	--	Yes	Yes	--
Increased Energy Consumption	Yes	Yes	Yes	Yes	Yes	--	Yes	Yes	--
Lost Revenues to the Utility	--	--	--	--	--	--	--	--	--
Environmental Compliance Costs	Yes	Yes	Yes						
Environmental Externalities	Yes	--	--						
Benefit									
Avoided Capacity Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Avoided Energy Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Avoided Transmission & Distribution Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ancillary Service Revenues	--	Yes	Yes	--	Yes	Yes	--	Yes	Yes
Market Price Suppression Effects	--	Yes	Yes	No	No	No	No	Yes	Yes
Avoided Environmental Compliance Costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	Yes	--	--	Yes	--	--	Yes	--	--
Participant Bill Savings	--	--	--	--	--	--	--	--	--
Financial Incentive to Participant	--	--	--	--	--	--	--	--	--
Tax Credits	--	Yes	--	--	Yes	--	--	--	--
Other Benefits	--	--	--	--	--	--	--	--	--

The benefits are also largely similar. The main difference is whether or not market price suppression effects are considered a benefit. The California framework explicitly does not incorporate price suppression as a benefit. As the protocols note, suppression of market prices affect the ability of generators to obtain revenues to pay its capital and fixed operating costs, which drives up the costs of capacity in an avoided cost framework.[42] The Ontario framework includes market suppression effects in name only. The model documentation notes that the empirical evidence indicates that those effects are short-lived and are the result of a sudden influx of demand response due to changes in market rules (Neenan 2005). In practice, the price suppression values are not included.

A.1.4 Issues That Have Not Been Fully Resolved

While considerable work has been conducted to develop cost benefit frameworks, there are many discussions that have not been finalized. The 2012 NAPDR's report lists a number of issues that have not been fully resolved and recommends further research on them. In addition, the CPUC held a workshop on demand response cost-effectiveness several months after the NAPDR report had been issued to propose and discuss resolutions to key unresolved aspects the CPUC's 2010 cost-effectiveness framework. These issues include:

- *How to account for demand response resource characteristics in estimating capacity value:* There is general agreement that capacity value – whether generation, transmission or distribution – needs to be adjusted based on the characteristics of different types of demand response resources. There is also general agreement about what characteristics need to be included in the valuation – availability by month and hour, maximum event duration, the maximum number of hours a resource can be dispatched, the amount of advance notification required, and differences in impacts by event hour. The issue of debate is how those adjustments should be made and how different characteristics affect value. The 2012 CPUC workshops on demand response cost-effectiveness directly addressed this issue and proposed a process for valuing demand response resources based on their characteristics. The valuation approach aligned with the OPA approach that had been in place since 2008. While the recommendations were generally accepted as an improvement by attendees, the changes have not been formalized into the CPUC protocols or models.
- *Participant value of service and transaction costs:* The common assumption is that a participant's value of lost service combined with its transaction costs are less than the financial incentives offered through participation in a demand response program; otherwise customers would not have enrolled. However, these costs are not well understood. Various models include a different fraction of incentives as participant delivery and transaction costs. The California framework includes 75% of incentives as participant costs. The OPA framework included 33%. Other applications, mostly in advanced metering infrastructure proceedings, have either entirely ignored participant costs for delivering demand response or assumed they were 100% of participant incentives.
- *Ancillary service benefits:* While the literature largely agrees that some demand response resources can provide ancillary services, either by delivering supply/demand balancing services or operating reserves, this value stream has rarely been incorporated into valuation in practice. Most frameworks indicate that demand response resources should bid into ancillary service markets to realize this benefit. However, the market themselves have been slow to adjust rules to allow participation of DR, particularly for aggregated resources such as air conditioning and water heating direct load control (Eto 2009, Sullivan 2013, Bode 2013). A North American Electric Reliability Council (NERC) special report on emerging flexible

[42] Capacity costs are the difference between the capital costs plus fixed operating costs and revenues that are expected to be recovered in the electricity and ancillary service markets by generators.

resources concluded that there did not appear to be any technical limitations in applying demand response to providing specific reliability functions. It recommended that system operators adjust market rules to allow participation of emerging flexible resources such as demand response.

- *Avoided T&D costs.* The NAPDR report summarized this issue well, stating "Some demand response programs offer the potential to offset transmission and distribution costs, but there remains considerable uncertainty as to the extent to which demand response programs will actually affect T&D investments, and the role that demand response should play in long-term T&D planning." *This uncertainty is in part driven by the fact the magnitude and ability to defer transmission or distribution costs is highly dependent on the specific of the electricity system design, the system component in question and the operational characteristics of demand response resources targeted at deferring such investments.*

There are additional benefits and costs to demand response that are agreed upon but are difficult to quantify according to the above frameworks. These include:

- *Reliability benefits:* Whether or not demand response leads to improved reliability and decreased outage costs depends on whether it is used as a complement or substitute for another resource.
- *Wholesale market benefits:* demand response is often cited as a means of improving the efficiency of wholesale markets, but there is little empirical data to demonstrate or quantify this (NAPDR).
- *Modularity benefits:* Demand response resources can typically ramp up or ramp down more quickly and at a more granular level than alternative infrastructure investment. As a result, they reduce the lumpiness of infrastructure investments and produce cash flow benefits. Demand response resources can also help meet reliability needs due to planning forecasting error or when construction of generation, transmission or distribution investments lags behind schedule.

A.2 Incorporating System and DR Characteristics Into Valuation

All the cost-effectiveness frameworks agree that avoided generation, transmission and distribution capacity costs are among the main sources of value for demand response (CPUC 2012, NAPDR 2012, Bode 2008, DOE 2006, and EPRI 2010). All of them also agree that, for demand response, most benefits accrue regardless of whether or not it is dispatched or needed in a particular year. All of them also concur that valuation needs to factor in specific attributes of demand response resources that affect its insurance value and that a central aspect to doing so is time-differentiating capacity value. This section discusses the literature on time-differentiating capacity value and factoring in characteristics of different demand response resources into the valuation.

A.2.1 Time-differentiating Capacity Value

Capacity can be thought of as a type of insurance against high peak demands. A unique feature of insurance is that it provides value even if it is not used each year. To illustrate, consider that most home and auto owners pay for insurance each year, but do not file an insurance claim each year. Comparing insurance is difficult, particularly when insurance characteristics differ. When auto policies differ with respect to the amount of the deductible, bodily insurance limit, property damage limit and/or roadside assistance, the insurance quotes are not directly comparable. The same is true for demand response and generation or for demand response and distribution investments (Bode 2009).

In the context of an electricity system, the insurance needs vary for different system components. Peaking conditions drive the need to invest in additional generation capacity as well as the need for additional transmission and distribution equipment and upgrades. However, the timing of the peaks that drives each type of infrastructure investment varies. The need for additional generation capacity is driven by system peaks. Transmission investments are usually tied to demand within specific load pockets and determined by the location and capacity of transmission lines and generators within the area. In contrast, distribution investments are driven by local peaks. Individual distribution networks experience different electric demand patterns and peak at different times depending on the mix of residential customers and small, medium and large enterprises. In short, the factors that drive the need for capacity – or insurance – vary depending on the components and its location in the electricity system.

Different resources provide different types of insurance. This is most easily illustrated with generation but also applies to transmission and distribution. There is no generator capable of operating at all hours without risk of failure. Peaking gas units experience unforeseen forced outages and also need to be closed down for maintenance on occasion. Hydro resources are subject to environmental restrictions on when and how much water can be released. Production for some renewable resources such as solar can coincide with peaking conditions, but the available resources vary by hour and are not near the nameplate capacity. Other resources such as wind are more volatile and their production can be at its lowest level when peaking conditions are low. At the distribution level, each component has a different risk of failure and the degree of risk varies with temperature (Billington 1996, NERA 2012). Likewise, the degree of insurance provided by different demand response resources varies. It depends on the specific characteristics of the resource such as availability by month and hour, maximum event duration, reductions for specific hours, etc.

A key task of cost-effectiveness analysis is properly valuing the insurance that different types of demand response resources provide. In making comparisons between resource options, the fundamental question is whether the insurance from demand response, given its features, is more or less costly than other options that ensure reliable service. This requires taking into account both how well the resource coincides with the need for additional capacity and the reliability of the resource.

The above mentioned factors drive the need to time differentiate risk. Figure A-1 illustrates the concept of risk allocation visually. It drawn from Schruder's paper titled *DR Evaluation, Cost Effectiveness, and System Planning* (Schruder 2011). Table A-2 shows the values underling A-1. The figure shows the allocation of the risk of shortages in generation capacity across months and hours of the day. The value spread across all months and hours adds up to 100%. The same type of risk allocation can and has been developed for specific transmission areas and distribution networks, although the concentration across hours and months would be different. This type of risk allocation is particularly useful because it can be used to factor in specific characteristics of DR. In the illustration, risk is concentrated in summer months and afternoon hours. A resource that is only available from 12–6 PM between June and September does not cover all the risk, but it is possible to calculate how much risk it does cover by adding the area under the curve for those months and hours.

Figure A-1: Example of Time Differentiated Risk Allocation[43]

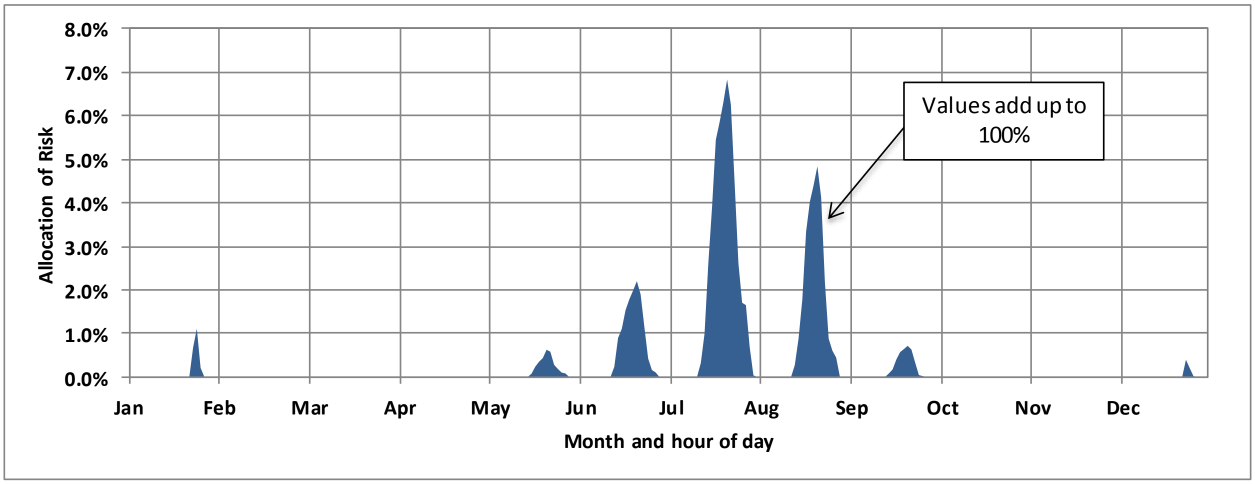


Table A-2: Example of Time Differentiated Risk Allocation With Availability and Maximum Dispatch Constraints

Hour	Month												Total
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.3%**
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	1.0%	0.3%	0.0%	0.0%	0.0%	0.0%	**1.5%**
11	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	2.6%	0.9%	0.1%	0.0%	0.0%	0.0%	**4.5%**
12	0.0%	0.0%	0.0%	0.0%	0.1%	1.1%	3.9%	1.8%	0.2%	0.0%	0.0%	0.0%	**7.0%**
13	0.0%	0.0%	0.0%	0.0%	0.2%	1.5%	5.4%	3.3%	0.4%	0.0%	0.0%	0.0%	**11.0%**
14	0.0%	0.0%	0.0%	0.0%	**0.3%**	**1.8%**	**5.8%**	**4.0%**	**0.6%**	0.0%	0.0%	0.0%	**12.6%**
15	0.0%	0.0%	0.0%	0.0%	**0.4%**	**2.0%**	**6.3%**	**4.4%**	**0.6%**	0.0%	0.0%	0.0%	**13.8%**
16	0.0%	0.0%	0.0%	0.0%	**0.6%**	**2.2%**	**6.8%**	**4.8%**	**0.7%**	0.0%	0.0%	0.0%	**15.2%**
17	0.0%	0.0%	0.0%	0.0%	**0.6%**	**1.9%**	**6.2%**	**4.1%**	**0.6%**	0.0%	0.0%	0.0%	**13.5%**
18	0.7%	0.0%	0.0%	0.0%	0.3%	1.1%	4.4%	2.2%	0.3%	0.0%	0.0%	0.4%	**9.4%**
19	1.1%	0.0%	0.0%	0.0%	0.2%	0.4%	2.6%	0.9%	0.0%	0.0%	0.0%	0.2%	**5.5%**
20	0.2%	0.0%	0.0%	0.0%	0.1%	0.2%	1.7%	0.6%	0.0%	0.0%	0.0%	0.0%	**2.8%**
21	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	1.6%	0.4%	0.0%	0.0%	0.0%	0.0%	**2.3%**
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.7%**
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.0%**
Total	**2.0%**	**0.0%**	**0.0%**	**0.0%**	**2.9%**	**13.5%**	**49.6%**	**27.8%**	**3.6%**	**0.0%**	**0.0%**	**0.6%**	**100.0%**

Each cell in Table A-2 reflects the share of capacity value allocated to the relevant hour of day and month. The light green shading indicates periods when the DR resource is available for dispatch. The example program is available for dispatch from 12-9 pm from April to September and between 4-9 pm for all other months. In total, the hours of availability cover 86% of the risk. The dark green shading

[43] The example is drawn from Bode and Schuder 2011.

reflects the effect of factoring in limits on the maximum duration that a DR resource can be dispatched. This restriction reduces the share of the risk that is covered from 86% to 58%. The yellow bars indicate the relative magnitude of the values in each cell. Multiplying the risk allocated to each month and hour by the overall avoided cost per kW-year time-differentiates capacity, transmission and/or distribution value. For example, 6.8% of the risk is allocated to the hour from 3-4 pm in the month of July. Assuming a capacity value of $100 per kW-year, a value of $6.80 would be allocated that specific time period. This process allows for the valuation to factor in differences in demand reduction capability by hour and month as well as load increases due to snapback effects or load shifting.

Multiplying the allocation of risk in Table A-2 by the hourly and monthly demand reduction capabilities – after factoring in limitations on availability, maximum event duration, maximum dispatch hours, etc. – and summing the values provides an estimate of Effective Load Carrying Capacity (ELCC). This metric summarizes how much additional peak load a resource can help support.

The ELCC metric was initially developed for incorporating different types of generators into system planning in 1966 (Garver 1966) and has been widely applied for estimating the capacity contribution of variable renewable resources (Madaeni 2012, Roger 2012, Milligan 2011). The concept is to identify how much additional peak load a resource can support given characteristics such as variable production level, months and hours of availability, forced outages and scheduled outages. In system planning, ELCC effectively serves as a translating mechanism so that the capacity contribution of gas peaking units can be compared to other resources such as hydro, nuclear, solar, wind and demand response.

In the distribution context, a similar process for time-differentiating capacity values has been applied to individual planning areas. The earliest application of time-differentiated distribution capacity costs was for PG&E's Delta Project (EPRI 1992). This is also the earliest documented application of demand side management for transmission and distribution deferral. In this project, the allocation of distribution capacity value was based on the magnitude of the loads in the top 100 hours. Two important questions are how to time-differentiate capacity value and how the process differs between generation capacity value and distribution capacity value. The approaches to time-differentiating capacity value typically rely on identifying when additional capacity is needed most. In other words, the more likely a system is to experience outages, the greater the value of demand reductions will be (IEA 2006). Approaches to allocating capacity value have relied on either output from probabilistic system planning models or analysis or on the incidence of high loads alone.

System planning reliability models combine the probabilities of generation outages with the probability of different demand levels to determine the combined likelihood that installed generation capacity is unable to serve load. Since it is not known in advance when annual peaks will occur, the probability of shortages is calculated by running the scenarios hundreds or thousands of times (Monte Carlo simulation). The outputs from these model runs are used to determine when the likelihood of supply shortages is highest. These outputs may include the loss of load probability (LOLP), loss of load expectations (LOLE), and the energy not served (ENS).[44] LOLP describes the likelihood of resource

[44] Energy not served is sometimes referred to as Expected Unserved Energy (EUE).

shortages; LOLE describes the expected number of hours with resource shortages; and ENS reflects both the likelihood and the magnitude of the shortages. The allocation typically normalizes these values so they add up to 100% over the course of all months, days and hours of the year. This is then used to allocate the capacity or insurance value across the year.

Load patterns have also been used to allocate capacity value. Bode and Schruder (2011) describe an "open-source" alternative that uses the concentration of system load in the top 100 hours by month and hour. The model relies on the concept that hours with high system load values are also the hours most at risk for resource shortages. It uses data from multiple years to incorporate a more complete range of weather patterns. Based on the risk allocation, one can say, for example, that 5% of the outage risk occurs in the hours between 3–4 PM in July, or that 25% of the outage risk is allocated between noon and 6 PM in August. The CPUC (2012) adopted an allocation approach that was based on loads alone, which were employed for the 2012-2014 Demand Response applications by each of the investor owned utilities in California.[45] In PG&E's transmission and distribution deferral pilot – the Delta project – the allocation of distribution capacity value was based on the magnitude of the loads in the top 100 hours (versus load above a threshold).

Two relevant questions are:

1. is the allocation transparent; and,
2. can the method be applied to allocate insurance value for transmission and/or distribution capacity?

Allocation of capacity value based on output from planning models is neither transparent nor can it be applied to distribution capacity. Schruder and Bode (2011) state that there are two big drawbacks to using output from planning models: first, LOLE models are typically highly confidential, which undermines their transparency and credibility to outsiders. Second, many LOLE models do not provide output at the hourly level; often, output is produced at the daily or weekly level. The CPUC declined the use of LOLE/LOLP models in its protocols for DR cost-effectiveness. They found that "the advantage of simplicity and transparency outweigh the advantages of proprietary traditional LOLE/LOLP models (CPUC 2012)," and adopted an approach that relied on load levels alone. They did, however, permit the use of allocation based on LOLE, LOLP and ENS provided that utilities make those models publicly available and produce sufficient documentation of their derivation to allow them to be verified independently. To date, no utility has provided such information.

In addition, allocation methods that rely on output from system planning models cannot be applied to transmission and distribution. These models are developed for the entire system and not for load pockets or distribution networks. In contrast, allocation methods that rely on loads can be applied to transmission and distribution capacity and are transparent. This latter feature has led to a preference by regulators to adopt *load only* approaches for time differentiating capacity value.

[45] These models are available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

A.2.2 Incorporating Demand Response Characteristics Into Valuation

All demand response valuation frameworks reviewed agree that cost-effectiveness analysis should factor in DR characteristics that affect the magnitude or resources available and their coincidence with the need for capacity. The OPA framework (Bode 2008, Schruder 2011) incorporates variability in resource levels, availability restrictions and maximum event duration. It also discusses the role of maximum dispatch hours and notification lead time, which are considered *de minimus* in the context of generation capacity. The framework used by Idaho Power and approved by Idaho Public Service Commission is similar to Ontario's (Idaho Power 2012). The CPUC protocols (CPUC 2012) outline five adjustment factors for generation capacity value. However, the protocols do not specify how utilities must make these adjustments. The NAPDR report (NAPDR 2012) recognizes there is general agreement that capacity values need to be adjusted based on demand response resource characteristics but notes that there remains a vigorous debate on how such adjustments should be made.

The primary topic of debate has been how to properly account for DR availability broadly defined by five characteristics:

- The hours of day and months when DR can be activated by the utility (on-call availability);
- The maximum number of hours that a program can be dispatched during a season (exhaustibility);
- The maximum duration of individual events;
- Differences in hour-to-hour demand reduction capability; and
- The speed of response or advance notification required.

The positions regarding what factors most affect capacity value have evolved. Table A-3 summarizes how four different models have addressed the above issues. The models are presented in chronological order and reflect the evolution of thinking over the past few years regarding how to adjust capacity value to factor in demand response resource characteristics. The earliest approach summarized (OPA), is remarkably similar to the last proposal by the CPUC. The only difference is the fact the OPA models incorporate hour-to-hour variation in reductions while the CPUC proposal did not. However, during the workshop, both the CPUC were open to incorporating hourly variation in resource availability. While the progression of these models indicate a convergence towards an answer, it does not reflect a consensus since the revisions to the CPUC cost-effectiveness model have not been adopted due to the lack of an open proceeding on the topic.

Table A-3: Summary of the Four Models

Resource Characteristic	OPA 2008-2012	CPUC 2012-2014 application[46]	PG&E Alternative 2012-2014 applications[47]	CPUC 2012 DR cost-effectiveness workshop[48]
	(FSC)	(E3)	(PG&E)	(E3)
Hours and months on-call (available for activation)	This is the main characteristic affecting the magnitude of the adjustment. A program that can be activated on weekdays between 12 and 8 PM during the months of May to October is considered to be available for roughly 1,000 hours. The capacity value allocated to those 1,000 hours is used for cost-effectiveness. In practice, the capacity value allocation is summarized in the table that contains the capacity allocations to each month and hour.	This is not a main component of the valuation.	An optimization algorithm factored in if the resource was available.	This was one of two characteristics affecting the magnitude of the availability adjustment. A program that can be activated on weekdays between 12 and 8 PM during the months of May to October is considered to be available for roughly 1,000 hours. The capacity value allocated to those 1,000 hours was to be used for cost-effectiveness. In practice, the capacity value allocation is summarized in the table that contains the capacity allocations to each month and hour.
Maximum number of dispatch hours	This characteristic is considered to affect the exhaustibility of a resource. It has a small effect for generation capacity value because resource shortage conditions are rare and DR programs typically have ample cushion to meet them. It plays a larger role in distribution capacity value, particularly for network components more likely to be overloaded.	This is the key component of valuation. Allocation of capacity value was based on the top 250 load hours. A program that could be dispatched for 100 hours captured 40% of capacity value (prior to other adjustments). A program with a 60 hour maximum captured 24% of the capacity value.	This was the key component of valuation. The allocation of capacity value was based on 132 hours with LOLE. The optimization assumed the hours with the highest risk could be targeted provided the resource was available. A program that could be dispatched for 100 hours captured at a minimum of 76% of capacity value (prior to other adjustments). A program with a 60 hour maximum captured at minimum 45% of the capacity value.	This characteristic is considered to affect the exhaustibility. It was not included in calculating the availability adjustment because the modeling showed that the likelihood of needing a resource due to capacity shortages was typically less than 10 hours. The framework did not discuss the relevance of this factor in relation to distribution capacity.
Maximum event duration	This is the second main characteristic affecting the magnitude of the adjustment. A program with the option of dispatching participants for six hours instead of four is available for more of the high risk hours, which often occurs on a handful of days.	Not a component of the adjustment.	Factored in using a dispatch optimization algorithm that assumed perfect dispatch.	This is the second main characteristic affecting the magnitude of the adjustment. A program with the option of dispatching participants for six hours instead of four is available for more of the high risk hours, which often occur on a handful of days.
Differences in hour-to-hour DR capability	This model factors in hourly estimates of demand reductions for monthly peaking conditions each month, as well as snapback.	The model relied on average demand reductions for each month for the 1-6 PM period for 1-in-2 weather year peaking conditions.	The model relied on average demand reductions for each month for the 1-6 PM period for 1-in-2 weather year peaking conditions.	The model relied on average demand reductions for each month for the 1-6 PM period for 1-in-2 weather year peaking conditions.

46 The CPUC models are available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

47 The PG&E alternative model (LOLP) is also available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

48 The presentations delivered at the workshop are available at:

http://www.cpuc.ca.gov/NR/rdonlyres/F8619E63-F001-4EA6-B512-EF4B6B9CD65E/0/DR_Costeffectiveness_Workshop_final.pdf

The models used for California's 2012-2014 Demand Response application proceeding did not clearly define differences between on-call availability and exhaustibility. Schruder and Bode (2011) discuss this distinction. Availability refers to the number of hours a resource is available for dispatch by operators (or on-call), regardless of whether it is utilized. Exhaustibility refers to the likelihood that a resource is exhausted too early due to how it is utilized. For example, a program that can be activated on weekdays between 12 and 8 PM during the months of May to October is on-call for roughly 1,000 hours. Those 1,000 hours may cover most of the periods with risk for local and system peaks. However, if the program is limited to a maximum of 100 hours for the summer, this limitation must be factored into the analysis. There are two key questions: what is the likelihood that the program will be dispatched for 100 hours due to extreme demand levels in any given year; and, what is the likelihood the resource event duration provides adequate coverage for the relevant hour on a given day?

Almost by definition, extreme system conditions are rare. This is acknowledged by the OPA models and the proposed revision to the CPUC framework presented at the October 2012 workshops. For example, most power systems are designed for 1-in-10 outage conditions, meaning that only 2.4 extreme hours are expected per year (24 hrs/10 years). In practice, most years do not experience extreme demand levels. Planning models simulate hundreds or thousands of potential outcomes and in most cases there are no resource shortages.

A resource that can be dispatched for more hours in a given year provides more flexibility – operators do not have to worry about potentially exhausting a resource prematurely or give them more room to err on the side of reliability. In general, monthly and hourly availability of a resource has a larger role in valuation than the maximum number of dispatch hours. A program that has a maximum event duration capped at four hours for a day may reduce risk of resource shortages on the key hours but will not be available on several high risk hours that fall outside of the event window. A resource that can be dispatched for up to six hours inherently has more value than one that can only be dispatched for four hours. This doesn't mean the resource needs to be dispatched for six hours each time it is activated, but that the option to do so is highly valuable.

A key shortcoming of the discussion regarding how demand response characteristics affect availability and capacity value is their application to distribution capacity. The OPA model can calculate a distribution level effective load carrying capacity, but currently uses a system wide allocation since OPA opted for a system-levelized approach. However, at the distribution level, the maximum hours a resource can be dispatched can play a large role, particularly when these resources are used to enable routine operations such as the transfer of loads from one network section to another.

A.3 Valuation of Demand Response Transmission and Distribution Benefits

The benefit of avoided T&D costs is mentioned in most cost-effectiveness frameworks but often overlooked in practice because estimating the magnitude of these costs is typically more challenging. Avoided T&D investment costs tend be highly location-specific and depend on many factors, including trends in customer load growth, load patterns, the amount of excess distribution capacity and equipment characteristics (e.g., failure rates) and uncertainty in growth forecasts. Both the NPPC and

NAPDR frameworks explicitly acknowledge that avoided T&D costs for demand response programs depend on the characteristics of the individual utility system (NPCC 2010, Woolf 2012).

In general, the requirements to avoid distribution investment costs are different in radial distribution systems than they are for distribution networks, which are more interconnected. Planning and reliability assessments for radial systems are fundamentally different than for parallel or meshed distribution networks (Billington 1996).

Many jurisdictions with mostly radial systems such as California only include T&D avoided investment costs for programs which are targeted to defer specific utility investments in the distribution system (NPCC 2010, CPUC 2012, Woolf 2012). Both the California and NPCC frameworks do not incorporate T&D savings for demand response unless utilities demonstrate that specific projects were deferred. By default, transmission and distribution benefits are assumed to be zero unless proven otherwise on a case-by-case basis.

Existing cost-effectiveness frameworks recognize three potential sources of benefits from reducing load growth and/or delivering load relief:

- Avoid or delay T&D upgrades, construction, and associated O&M costs;
- Reduce equipment degradation and the frequency of maintenance by reducing the amount of time the transmission component carry loads at or near design capacity; and
- Improve reliability when upgrades are delayed.

Deferral of T&D investments can have significant economic value. The value of the deferral is calculated by looking at the present value difference in costs between the project as originally scheduled and the deferred project.

There are two main approaches to valuing the effects of demand response on transmission and distribution investments: A. a targeted approach (also referred to as present worth); and B. a system-levelized approach.

A: The targeted approach relies on determining where transmission and distribution investments are imminent and targeting demand response, energy efficiency and distributed generation at these locations in order to offset known, upcoming investments. Investment needs are modeled with and without demand response in order to calculate how long the expected demand reduction will defer the need for the investment. Under this approach, the value of demand response is tied to the time value of money implicit in delaying the transmission investment for a specific amount of time. As a result, the avoided T&D value of demand response is a function of:

- The magnitude of demand reduction;
- The location of the demand reductions;
- When the demand reduction capability is available or on-call;
- How well demand reductions coincide with the local need (which may differ at transmission and distribution levels);
- How soon the investments are needed;
- How long the investments are deferred; and
- The value of the deferred or avoided investment.

This approach has been applied in several settings. It was first presented by in the PG&E Delta Project (EPRI 1992). It has also been use develop granular estimates of T&D capacity for energy efficiency and have been shown to vary considerably depending on geographic region and other factors.

Figure A-3: California Avoided T&D avoided costs by utility and Planning Area 2003[49]

Figure A-3 was for developed for the California Public Utilities Commission as part of energy efficiency benefit cost analysis by E3 and the Rocky Mountain Institute (E3 and RMI, 2004; Baskette et al., 2006). It was developed using the present worth method and illustrates how avoided costs of T&D capacity varied in California (in $/kW-year) by planning area, utility, climate zone in 2003.

The targeted approach has several advantages. It reflects the time-pattern and unevenness or lumpiness of larger T&D investments. It is also reflects key differences across specific planning areas based on where T&D investments are projected to occur. Lastly, it is particularly relevant of radial distribution systems which require the right investment at the right place in order to defer T&D investments.

The targeted approach also has disadvantages. It cannot be used to isolate an individual program since all programs – including demand response, energy efficiency, and distributed generation – are jointly analyzed.[50] It also requires detailed information about the magnitude, timing and cost of expected network reinforcement. It can also understate benefits in that it only includes future

49 Source: Baskette et al., 2006.

50 With the targeted approach, analyzing the deferral value of each individual program or option and summing the results produces a different value than jointly analyzing the effect of all demand side management programs.

investments that have been identified, typically within a ten year horizon. In practice, additional transmission and distribution investments can be expected outside of the traditional planning horizon.

B: The system-levelized cost approach allocates the avoided costs associated with reduced load growth across an entire area. Typically, the value is estimated by modeling the transmission and/or distribution system with and without demand response. The net benefit of demand response is then distributed across the entire system or calculated for specific zones. This approach was adopted to estimate transmission and distribution benefits for CECONY and Hydro One (NERA 2012; Navigant 2005. An alternative way to calculate a system's levelized costs is to compare the aggregate load growth over a time period with the aggregate transmission and distribution investments associated with new load growth (upgrades due to aging or failed equipment are excluded). These load growth related investments are divided by the actual or projected load growth over the same time period in order to estimate the transmission and/or distribution investment required per kW of load growth. This latter approach is retrospective; it is based on investments that occurred in the past rather than on investments expected to occur in the future. It has been extensively use in New England. The 2011 Avoided Energy Supply Costs Study summarizes the transmission and distribution cost studies produced for National Grid, Connecticut Light & Power and United Illuminating (Synapse 2011).[51]

In general, system-levelized approaches understate the value of demand reduction in constrained areas and overstate the value of demand reduction in areas where upgrades are not needed. The retrospective approach has also been critiqued for using sunk costs to calculate the T&D benefit, when in fact the expected investments in future periods is required. Another critique of the system-levelized approach is that it ignores differences in the expected timing of investments and the in the amount of time that investments are deferred. In other words, it does not reflect the fact that value of the avoided distribution costs can vary by location and time. This critique may be less relevant for distribution network such as CECONY's that are highly interconnected. With a radial network design, the right amount of demand response is needed at the right location and the right time; otherwise, the distribution investments aren't deferred. In contrast, with a meshed network, a reduction almost anywhere in the network provides load relief. The exception is system components such as smaller distribution transformers that step down voltage for a small number of customers.

An alternate approach is to develop levelized by type of network. The study NERA conducted for CECONY details that the costs vary by geography due to terrain and density issues (NERA 2012). In addition, the initial estimates of marginal investment were made on a geographic basis prior to calculating the system weighted costs.

[51] Two studies are referenced by the report but do not appear to be publicly available: United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009, and; Assessment of Avoided Cost of Transmission and Distribution, ICF International, October 30, 2009.

A.4 Key Findings

Cost-effectiveness evaluation frameworks address three fundamental questions about a program: What is the analysis perspective? Are the benefits and costs properly identified and classified? And, are cost and benefits properly valued?

As this literature review has discussed, earlier cost-effectiveness frameworks for DR programs have largely agreed on the answers to the first two questions: a comprehensive study must evaluate the program from multiple perspectives (Societal, Total Resource Cost, and Utility Cost) and take into account a set of widely accepted costs and benefits (see Table 2-1). Most disagreement about an appropriate framework has centered on the third question. Prior attempts at estimating the effectiveness of demand response programs have only partly succeed at quantifying costs and benefits. These previous frameworks largely agreed on the general categories of benefits, but used different approaches to estimate their magnitude.

Despite a number of efforts to develop cost-effectiveness frameworks specific to DR, several issues are not entirely resolved, most notably how to adjust the valuation of a program based on DR resources and system characteristics and how to appropriately include transmission and distribution benefits. Since the latest DR framework documents were drafted progress has been made in regulatory workshops towards agreement between the California, NPCC and OPA frameworks on this important issue The CPUC and its Consultant, E3, proposed adjustments to the valuation process that conceptually align the OPA and CPUC framework, but these changes have not yet been formally adopted. In its 2011 regulatory filings, Idaho Power (an NPCC member) factored unique characteristics of individual DR resources in the same manner as OPA.

Another key finding is that all of the DR specific cost-effectiveness frameworks adopted thus far have been in regions that lack organized capacity markets. These regions do not have to contend with different entities, such as utilities and independent system operators, calling demand response events for the same customers for different purposes. As a result, the frameworks do not dedicate substantial effort to sorting out overlaps that can occur when different entities targeted different aspects of the electricity system.

There is less uniform thinking when it comes to including benefits of DR programs from deferral of transmission and distribution investments. It is generally agreed that DR programs can provide substantial benefits in the form of deferred and avoided transmission and distribution upgrades. The literature also agrees that benefits depend on configuration of the transmission and distribution system and that they can vary substantially based on location and timing. However, there is limited consensus about when those benefits should be accrued. Some frameworks automatically include transmission and distribution benefits while other jurisdictions require utilities to prove each and every project deferred through DR before claiming those benefits.

Importantly, the frameworks adopted thus far do not consider the value of DR for network distribution systems, which predominate most of CECONY's territory but are uncommon in other jurisdictions. The requirements for DR to help defer distributions investment in networks is fundamentally different s than they are for radial or parallel distribution systems. There is limited experience outside of New York on how DR affects investment decisions when the distribution networks are designed with enough redundancy to support two feeder outages on any given network. Not surprisingly, the literature does not discuss avoided distribution capacity costs in this context. It also does not consider whether additional DR benefits can accrue in distribution networks that are highly reinforced.

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Appendix B Prior Model and Gap Analysis

B.1 Prior Cost-effectiveness Model Deficiencies and Gaps

CECONY's current cost-effectiveness models consist of a series of spreadsheets that show Total Resource Cost (TRC) test results for various demand response (DR) programs. These results are provided for a set number of years into the future. The model has five main shortcomings:

- It does not fully take into account the characteristics of DR;
- It does not account for the fact that peaking load patterns vary by network;
- It does not account for costs in a flexible manner;
- It includes all incentives as costs; and
- It only summarizes cost-effectiveness from the total resource cost – or all customers – perspective.

The main shortcoming in CECONY's existing model is that it does not fully take into account the operational characteristics of DR programs. The DR value is not adjusted for the availability and exhaustibility of the demand resources, limits on event duration or number of hours the demand resource can be dispatched, the amount of advance notification required or the fact that some DR resource provide deliver different amounts of demand reduction depending on the hour of day and/or weather conditions. There is general agreement that different types of demand response resources have different characteristics, and therefore adjustments need to reflect how well resources coincide with the drivers for additional generation, transmission and distribution capacity. CECONY's analysis takes into account a realization rate, but this is essentially just a deration factor accounting for the fact that not all of the load reduction commitments were delivered in practice. CECONY's analysis also only includes one load impact value, while most DR programs perform differently in different months and hours. This is particularly true for direct load control.

The coincidence of DR resources and their availability with capacity needs is critical. Just because a resource such as AC direct load control can, for example, yield up to 1 kW per device does not mean 1 kW should be included for cost-effectiveness, unadjusted. AC loads and demand reductions vary substantially based on weather conditions and by hour of day. If the resource is not available for critical periods because it can only be dispatched for four consecutive hours, that resource does not provide value during all critical periods. If it is available, but the 1 kW maximum demand reductions does not coincide with when the resource is most needed in a particular network, it is simply not as valuable.

Another shortcoming of the existing model is that it does not address the fact that peaking load patterns – the primary driver of distribution capacity costs – vary by network. The need for distribution investments is driven by local peaks, the amount of excess capacity in the network, and the reliability of the network. Different networks peak at different times. Some networks peak during the day, some peak during the evening and a small share of them have peaks that last across the day and into the evening. How well demand reductions coincide with network peaks is critical. Investments are also driven by the amount of excess capacity in the network. Networks with less excess capacity or cushion are more difficult to operate and have a higher need for additional resources.

The existing cost-effectiveness model implicitly assumes that avoided distribution costs are the same regardless of the characteristics of the network. It also implicitly assumes that load reductions coincident with network peaks are the same irrespective of when specific networks peak. While data regarding distribution investments associated with load growth are available for each network and for different distribution components, the model can only take in a single levelized value as an input for each year. A key area for improvement is to develop a framework that can analyze different network types. Allowing inputs for different types of networks more fully reflects the fact that DR provides more value in some networks than in others and that the concentration of capacity value varies across networks.

Another limitation of the existing model is its treatment of costs. CECONY's current models express almost all costs in terms of dollars per kW or dollars per kW-year, including fixed cost and equipment costs. This approach creates circularity in the model. The cost inputs are not independent of impacts and need to be adjusted based on the impacts, making it difficult to conduct sensitivity analysis. In some cases, costs are directly tied to the Megawatts enrolled in the program. This is particularly true for aggregator programs that pay for pre-specified demand reduction amounts. For many programs, however, costs such as the equipment and communication costs are tied to the number of participants (or devices) rather than to the total number of MW expected from the program. The model should be able to incorporate both types of cost inputs. A related issue is the treatment of sunk or start-up costs. The existing model includes start-up costs that occurred in the past (sunk costs) in the cost calculations for future years. This occurs in the CSRP program spreadsheet. It could be technical mistake or a conceptual error. Doing so is akin to asking if the program would have been cost-effective if we could travel back in time. The decisions that cost-effectiveness analysis informs are forward looking: is it cost-effective to continue to operate an existing program; is it cost-effective to increase participation; and, is it cost-effective to launch new programs? Investments that occurred in the past have limited bearing on decisions about whether to operate or expand programs.

The CECONY model also deviates from currently accepted practice in its treatment of participant costs. Both the Total Resource Cost and Societal tests recognize that incentives are a transfer from one set of customers – non-participants – to customers participating in the program. The existing TRC tests include all customer incentives as costs.[52] All of the current benefit cost frameworks also include costs borne by participant to deliver DR. The existing CECONY models do not separately include participant costs. Unlike energy efficiency measures – which seek to reduce energy use by providing the same level of service and comfort using more efficient technology – demand response often, but not always, reduces a customer's demand by modifying their level of service and comfort. This is not universally true since some operations can be shifted to different hours at no loss to the customers and backup storage (e.g., uninterruptible power systems) can eliminate costs of temporary demand reductions. Those costs often cannot be directly observed but are logically less than the incentives paid to participants.

[52] Customer incentives paid are categorized as costs from the Utility or Program Administrator perspective.

Finally, the existing CECONY models only include the TRC test. It does not include other relevant perspectives on cost-effectiveness such as the utility's perspective or the rate payer impact.

A final issue is that the benefits included differ by program. For example, the direct load control program model includes avoided generation capacity costs while the CSRP model does not. This is not shortcoming on its own. However, the logic for the differences is no clearly documented. It appears that avoided generation capacity costs are included as a benefit stream for resources that do not overlap with the New York Independent System Operator DR programs.

Appendix C Model Architecture

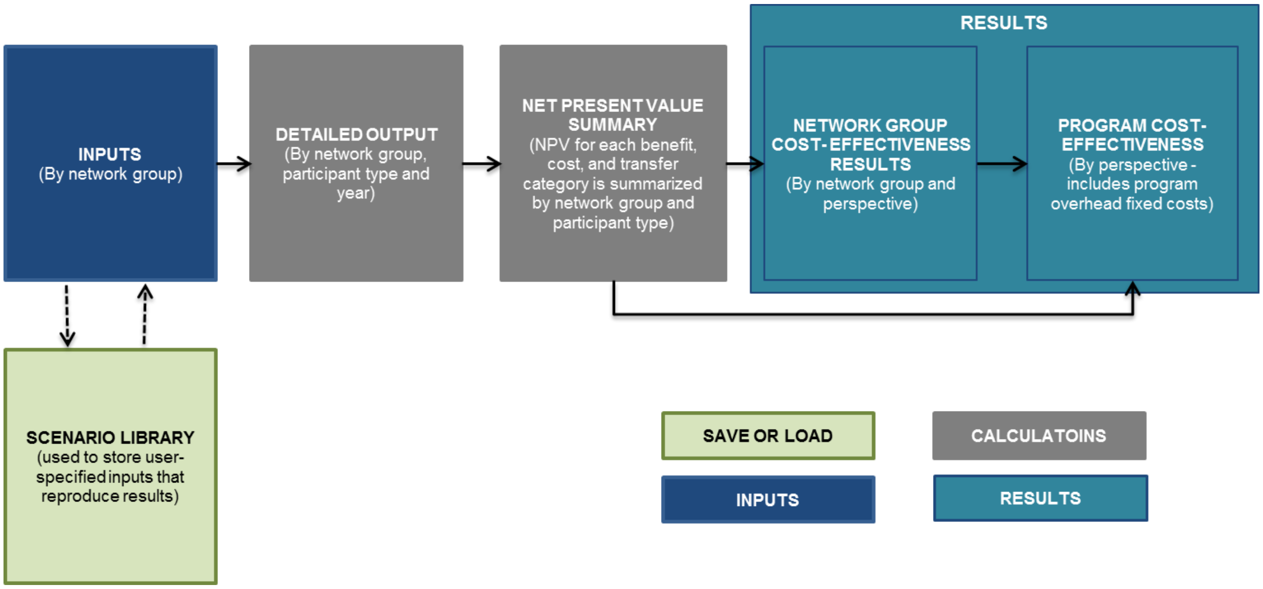
The demand response cost-effectiveness model is a flexible tool that is useful for estimating program cost-effectiveness and for providing program design and targeting strategy insights. The model not only allows for comparisons of different program designs but also of different types of DR programs with different operational characteristics.

CECONY's DR programs are designed primarily to provide relief to the distribution system when demands are high or when emergency conditions occur. Because network characteristics directly affect value and the degree to which DR can be used to manage peaks, it was critical to avoid assuming that all distribution areas are alike and to develop a model with sufficient granularity to reflect key differences.

A key, early scoping decision was to design the model to conduct a bottom-up analysis for eight different prototypical network groups. Each of CECONY's 83 distribution areas (69 networks and 14 non-networked areas) were categorized into eight groups based on network/non-network status, load shape, amount of excess capacity and risk of cascading failures as reflected by NRI scores. This decision has several implications. First, the user can include different inputs by network group. For example, incentive payments, costs, enrollment levels, strategy and demand reduction performance can vary by network group. Second, the calculations are also conducted separately for each network group and then aggregated to produce program level results. While the decision to separately conduct calculations for each of eight network groups provides more user flexibility and more accurate estimates of cost-effectiveness, it does not come without cost. It expands the number of inputs required and the amount of calculations conducted. As a result, we start with a simplified sketch of the model architecture and then add more details to fully reflect how the model works.

Figure C-1 illustrates the flow of data and calculations in a simplified manner. It does not reflect the different worksheets in the model. When the user specifies inputs, a series of detailed calculation automatically occur in the model engine which in turn automatically updates results. The detailed calculations are conducted by network group for each year in the analysis period for both existing and new participants. The distinction between new and existing participants is critical for tracking costs, which can differ between the two groups, as well as for understanding whether expanding the program improves or reduces overall cost-effectiveness. The detailed calculations track information such as new enrollment, demand reductions, individual benefit streams and individual cost streams. Next, the net present value (NPV) of each of the costs, benefits and transfers stream is calculated for each of the network groups, for both new and existing participants. These are summarized in a worksheet titled *NPV Summary*. The summary of net present values is then used to calculate cost-effectiveness. Depending on the perspective, different benefits and costs are included in the cost-effectiveness calculation. Key cost-effectiveness outputs – total benefits, total costs, net benefits and benefit cost ratio – are calculated for each network type. These estimates do not include fixed overhead costs that are collectively shared; that is, they do not include costs that cannot be attributed to specific network groups. As final step, the benefits and costs from each of the eight networks groups are then aggregated, along with program fixed overhead costs, to calculate the program's cost-effectiveness.

Figure C-1: Cost-Effectiveness Data Flow and Calculations

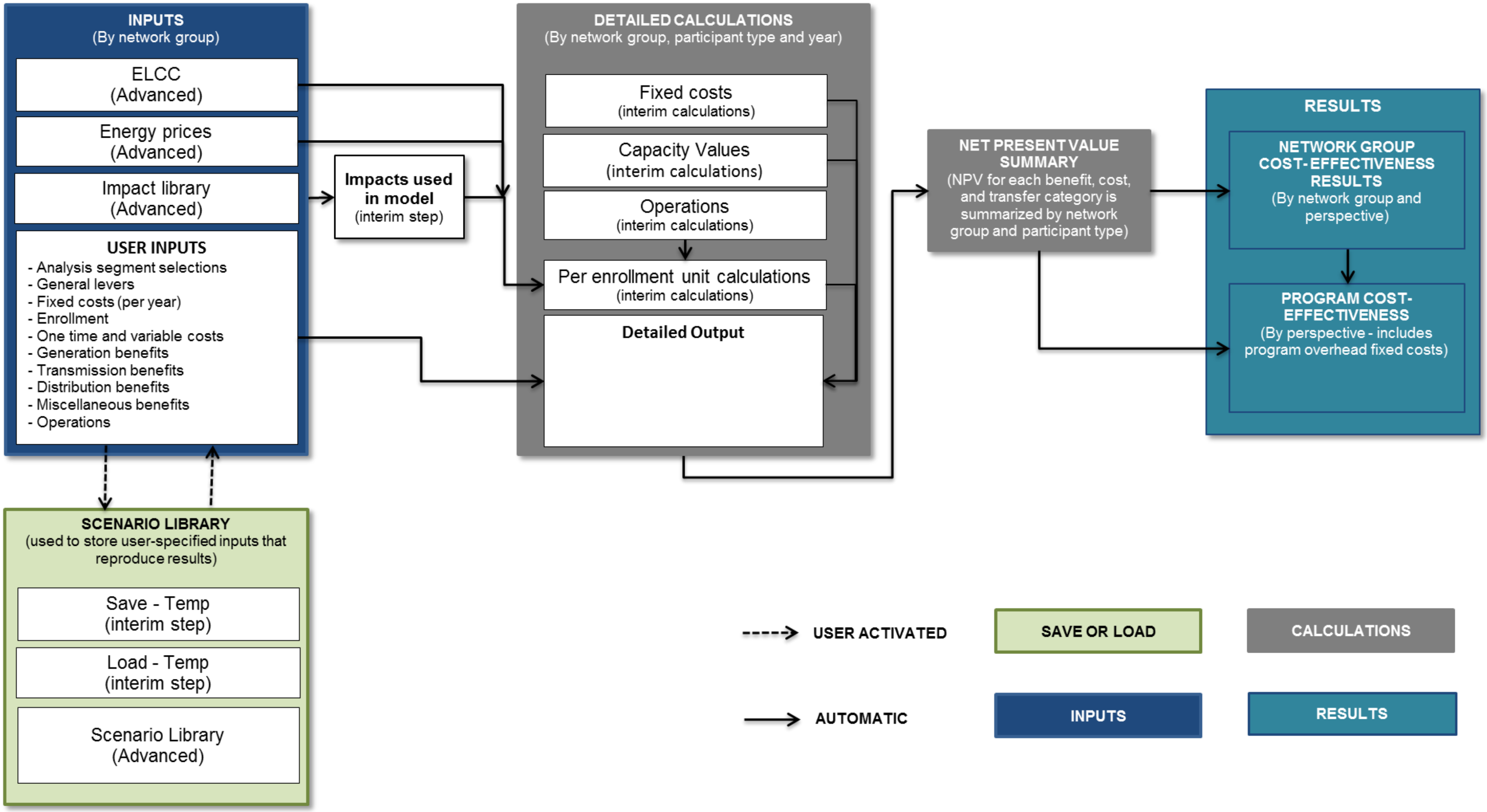


The model also has the ability to load and save scenarios. Since the inputs are directly linked to the results, reproducing the same set of inputs replicates the results. When clicked on, the save and load scenario buttons in the Inputs worksheet simply store or load user specified inputs. There are several advantages to including the ability to save and store multiple scenarios within a spreadsheet. It allows the cost-effectiveness results for all programs and strategic options to be saved in a single model, rather than having to store and track different spreadsheets for different programs or strategic scenarios. It also facilitates use of the model. Rather than having to specify each of the numerous inputs, the user can choose to automatically fill-in program characteristics by selecting and existing scenario and proceed to update or modify it. The changes can be saved over the existing scenario or be stored as new scenario.

In practice, there are two types of inputs: those readily available, which are located in the main inputs page, and those for more advanced users, which include demand reduction estimates and wholesale market prices. These more advanced inputs are located in separate spreadsheets. There are a few supplemental worksheets used to either conduct interim calculations or to ensure the model is robust to sorting by the user. The supplemental worksheets feed into the detailed calculations but were separated either to minimize the risk of error by avoiding overly complex formulas or because the interim calculations (e.g. max and adjusted reduction per enrollment unit) are interesting on their own. Finally, there are two ancillary worksheets which enable users to load and save different scenarios.

Figure C-2 (next page) presents the full architecture of the model. Each box represents a separate worksheet within the model. The model user guide provides more detail regarding how to operate the model, the specific definition for user inputs and interpretation of the results. Table C-1 below describes each of the worksheets in the model and its role.

Figure C-2: Detailed Model Architecture



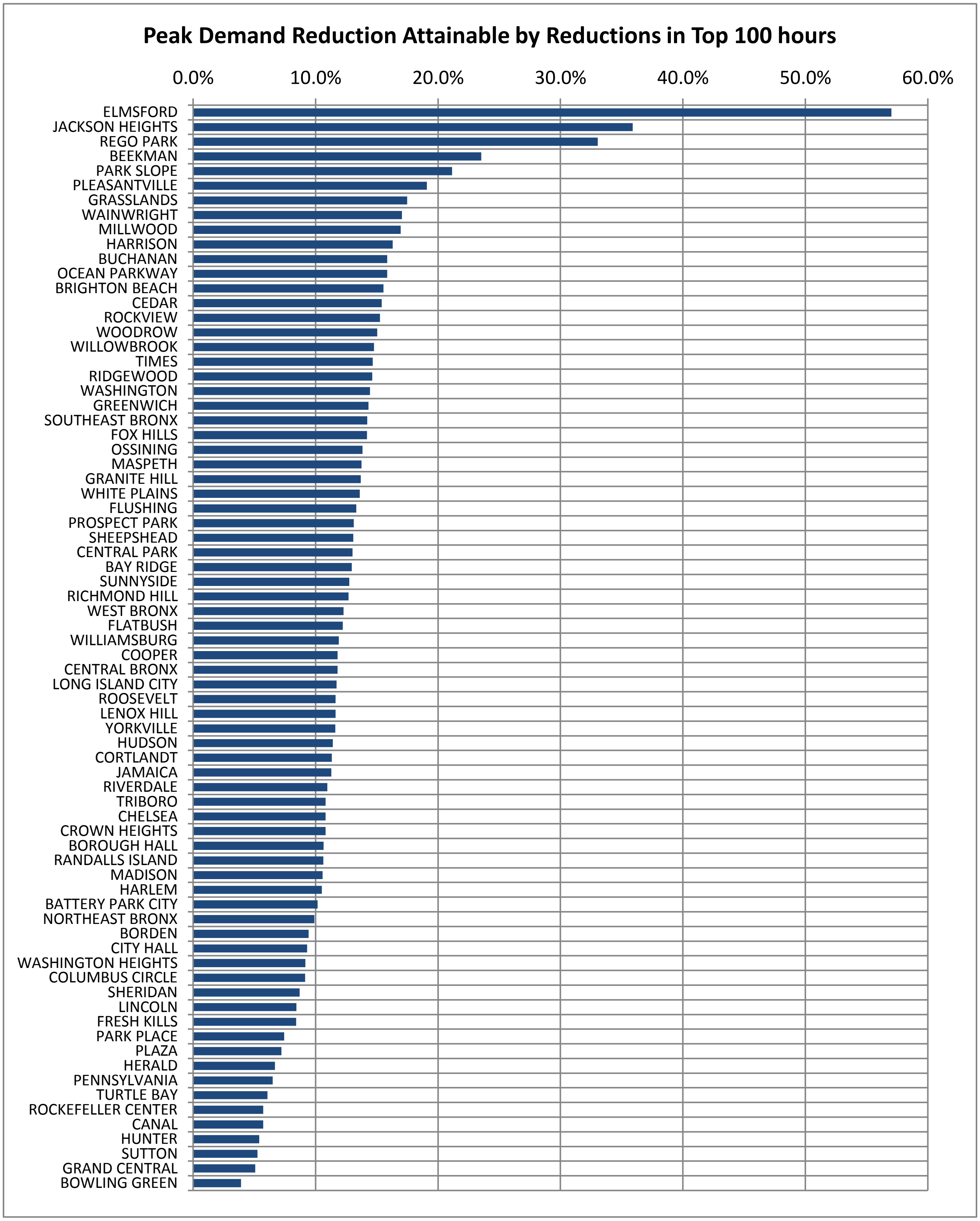
Each box represents a specific worksheet in the model. Interim steps and calculation are hidden. A basic-level user will primarily be concerned with how to fill in *Inputs* to reflect different programs and strategic scenarios and with how to interpret *Results*. A more advanced user should learn how to update advanced user inputs such as the *Impact Library, Energy Prices* and *Peaking Risk Allocation*. An expert user should be familiar with the mechanics of the calculations.

Table C-1: Model Worksheet Descriptions

Function	Worksheet name	Type of user	Description
Save or Load	Scenario Library	Advanced	This worksheet is hidden and used to store user-specific inputs for different scenarios. Since the inputs are directly linked to the results, reproducing the same set of inputs replicates the results. Saving, loading and deleting scenarios are controlled from in the *Inputs* worksheet.
	Save - Temp	Expert	This worksheet is hidden and used to facilitate saving of scenarios. It mirrors user inputs and restructures them so they can be easily stored.
	Load - Temp	Expert	This worksheet is hidden and used to facilitate loading of scenarios. It determines if the scenario selected by the user in the *Inputs* worksheet exists and, if so, reads in those inputs and restructures them so they can be easily loaded should the user click the button.
Inputs	Inputs	Basic	It includes the primary user controls. In this worksheet the user specifies which programs and network groups to analyze. They also include the main inputs and strategic decisions that affect cost-effectiveness. Scenarios developed in this worksheet can be saved, loaded or deleted.
	Impact Library	Advanced	This worksheet houses the standardized demand reductions (or load impacts) for each program, network group and event duration, by hour and month. It includes separate inputs for non-event energy savings (average weekday) and for curtailment events. For programs with a contractual reduction obligation (DLRP and CRSP), the values reflect the performance factor or share of pledged reductions that historically have been delivered. For other programs (DLC and CoolNYC), they reflect the hourly load reductions per device.
	Energy Prices	Advanced	This worksheet includes the energy prices by hour and month for the average weekday (used to calculate non-event savings) and for monthly peak days (used to calculate event day savings).
	ELCC	Advanced	This worksheet includes the peaking risk allocation by hour and month for each of the eight network groups as well as NYISO system peaking risk. This data is used to assess how well demand reductions coincide with when peaks are most likely to occur. This is used for valuation since several capacity related investments are driven by local or system peaks.
Calculations	Impacts used in model	Advanced	This is an interim spreadsheet used as a place holder. It does not conduct calculations per se but simply extracts the relevant impacts from the library. This step is included as a safeguard to ensure that sorting or filtering by the user does not affect the calculations.
	Fixed costs	Expert	This worksheet simply annualizes fixed costs during three periods – growth, maintenance, and slow down – based on user inputs. The values feed into the *Detailed Output* worksheet. These calculations were separated to minimize the potential for error.
	Capacity values	Expert	This worksheet simply annualizes distribution, transmission and generation capacity values for 30 years based on user inputs. The values feed into the *Detailed Output* worksheet. These calculations were separated to minimize the potential for error.
	Operations	Expert	This worksheet simply tracks the number of non-event days. These values are needed to calculate non-event day energy savings, if the program delivers such savings. The values are used to produce non-event day energy savings estimates per enrollment unit. These are presented in the *Per enroll unit calcs* worksheet which in turn feed into *Detailed Output.*

Function	Worksheet name	Type of user	Description
	Per enroll unit calcs	Basic	This both an interim calculation and a results worksheet. It calculates how well reductions coincide with peaking conditions that drive different capacity investments (distribution, transmission, generation), factoring limitations on availability, event duration, and load shifting or snapback. It also calculates per customer maximum reductions and energy savings. The per enrollment unit values are used for a number of calculations in the *Detailed Output* worksheet.
	Detailed output	Expert	This worksheet is the core engine of the model. It tracks enrollments, demand reductions and energy savings by network group and type of participant (new/existing) for each year of the analysis period. It also calculates each benefit and costs stream by network group and participant type. These calculations feed into the *NPV Summary* and ultimately into the *Results*.
	NPV summary		This spreadsheet summarizes the Net Present Value (NPV) over the analysis period for each benefit, cost, and transfer/other category by network group and participant type (new/existing). The summary of net present values is then used to calculate cost-effectiveness, which are presented in the *Results* worksheet.
Results	Cost-effectiveness by network group	Basic	Cost-effectiveness results by network group and for the program overall both reside in the Results worksheet. Depending on the perspective, different benefits and costs are included in the cost-effectiveness calculation. First, key cost-effectiveness outputs – total benefits, total costs, net benefits and benefit cost ratio – are calculated for each network type. Key cost-effectiveness outputs – total benefits, total costs, net benefits and benefit cost ratio – are calculated for each network group and participant type (new/existing). These estimates do not include fixed overhead costs that are collectively shared; that is, they represent the marginal cost-effectiveness. As final step, the benefits and costs from each of the eight networks groups are then aggregated, along with program fixed overhead costs, to calculate the program's cost-effectiveness
	Program cost-effectiveness	Basic	

Appendix D Networks by Concentration of Peak Demand

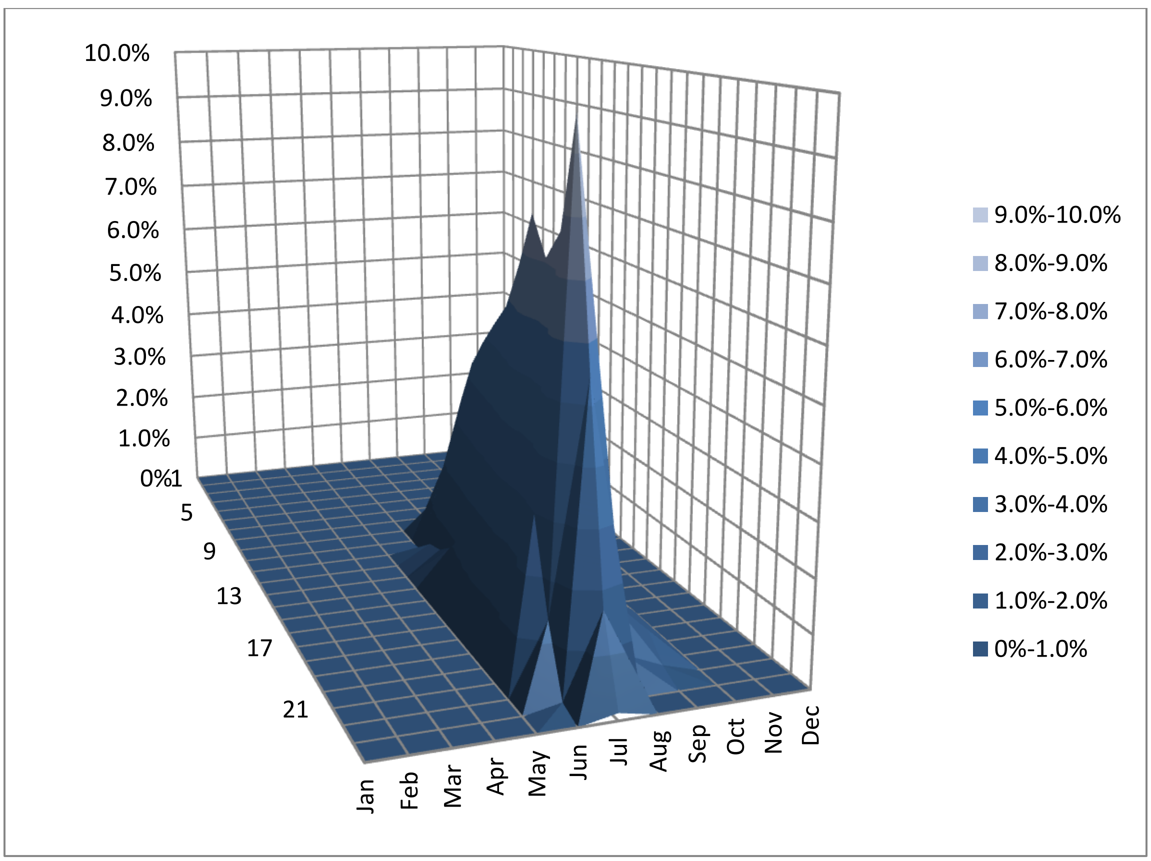


*Excludes eight distribution areas for which hourly data was missing.

Appendix E Allocation of Peaking Risk

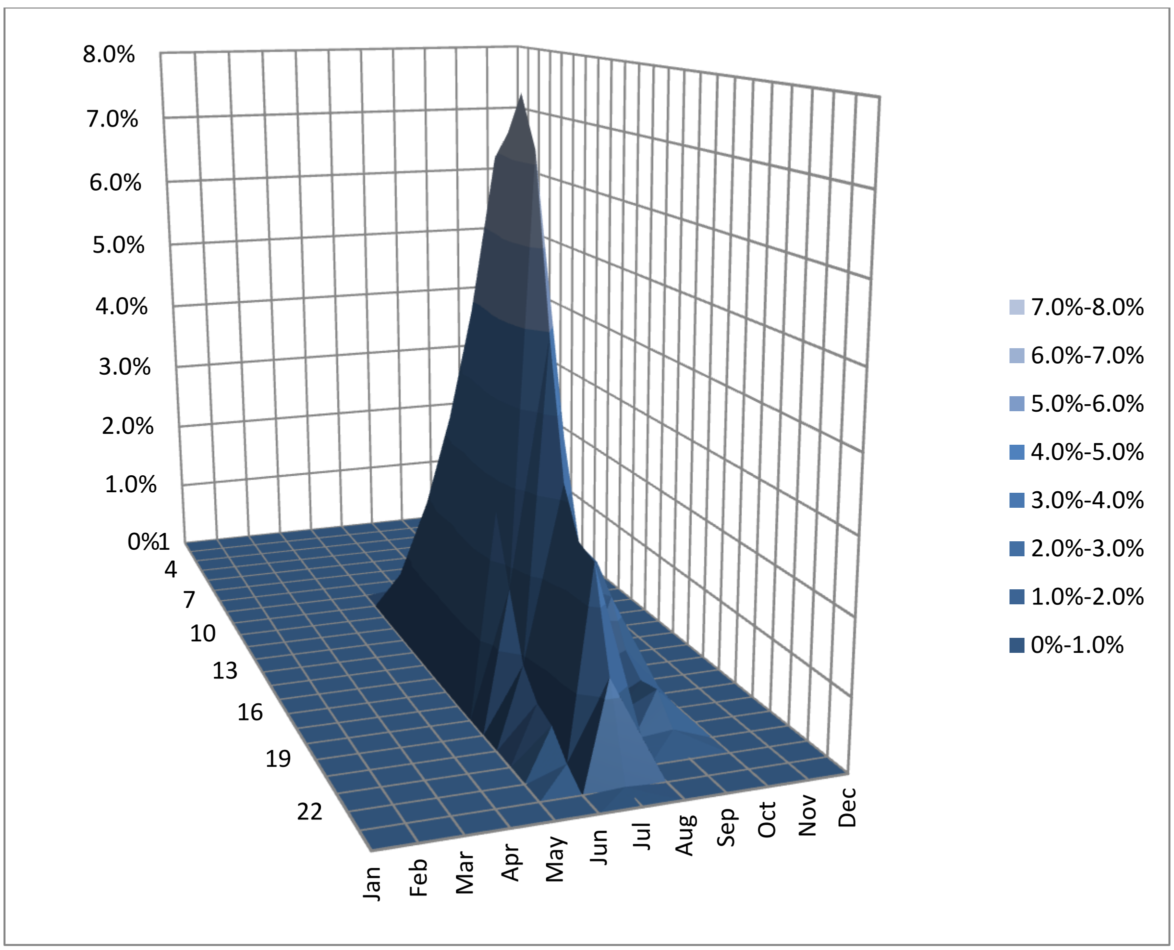
E.1 Tier 2 – Evening Peak Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	1%	6%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	2%	7%	1%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	2%	8%	1%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	2%	7%	1%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	2%	8%	1%	1%	0%	0%	0%
21	0%	0%	0%	0%	0%	3%	10%	1%	1%	0%	0%	0%
22	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



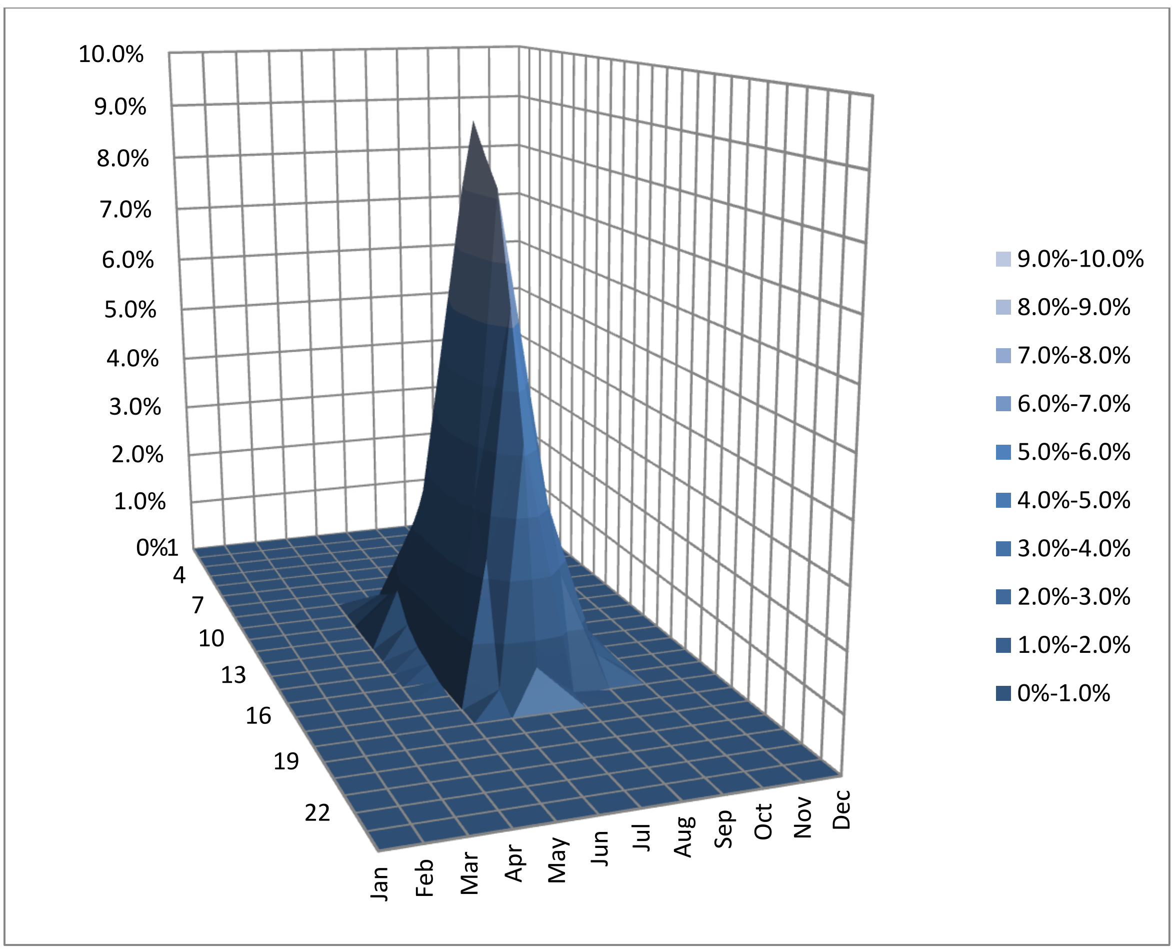
E.2 Tier 2 - Day Peak Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	2%	3%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	2%	4%	0%	1%	0%	0%	0%
13	0%	0%	0%	0%	0%	3%	6%	1%	1%	0%	0%	0%
14	0%	0%	0%	0%	0%	3%	7%	1%	1%	0%	0%	0%
15	0%	0%	0%	0%	0%	3%	7%	1%	2%	0%	0%	0%
16	0%	0%	0%	0%	0%	3%	8%	1%	2%	0%	0%	0%
17	0%	0%	0%	0%	0%	3%	7%	1%	1%	0%	0%	0%
18	0%	0%	0%	0%	0%	2%	5%	0%	1%	0%	0%	0%
19	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	3%	0%	1%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



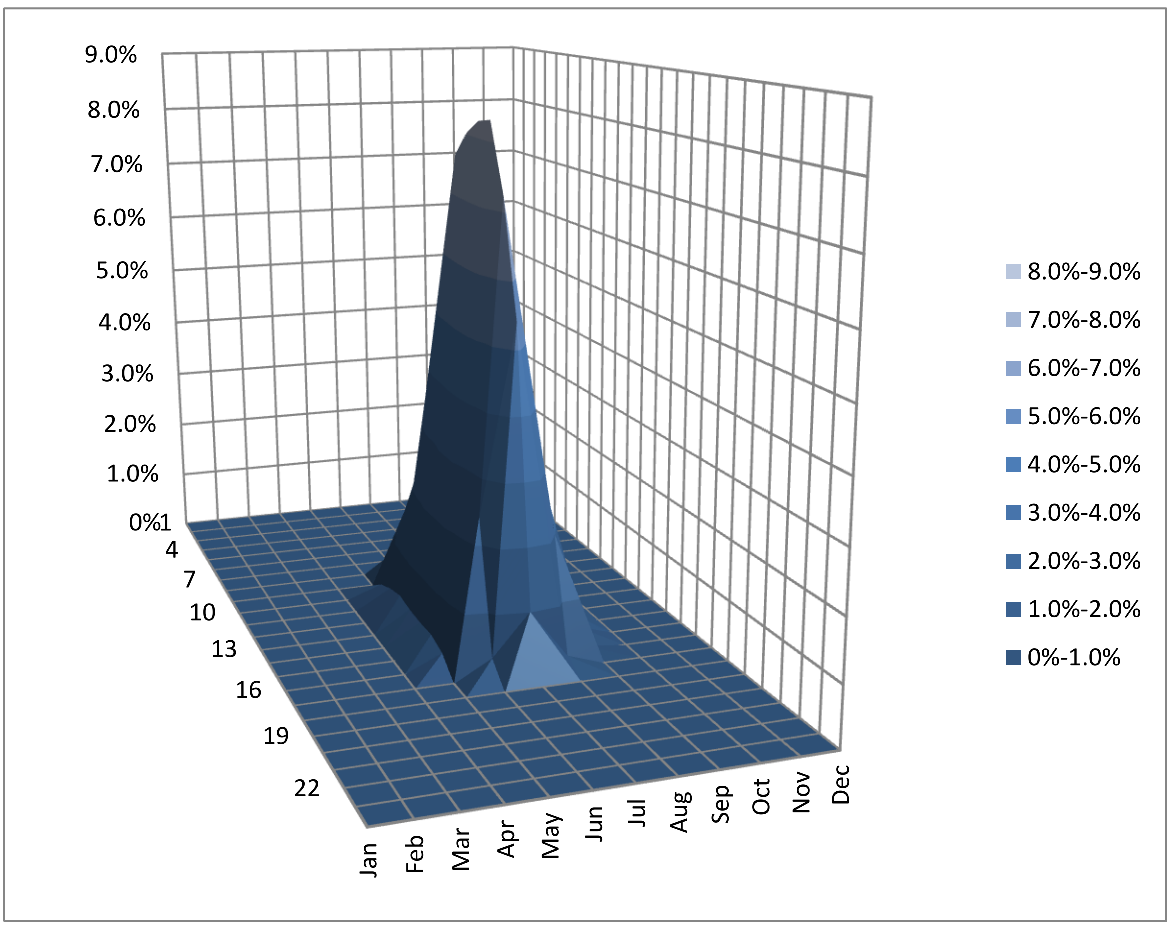
E.3 Tier 1 – Day Peak – Low Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	1%	2%	6%	1%	0%	0%	0%	0%
11	0%	0%	0%	0%	1%	3%	8%	2%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	4%	9%	3%	1%	0%	0%	0%
13	0%	0%	0%	0%	0%	4%	9%	4%	1%	0%	0%	0%
14	0%	0%	0%	0%	0%	4%	8%	4%	1%	0%	0%	0%
15	0%	0%	0%	0%	0%	3%	6%	3%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	2%	4%	2%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



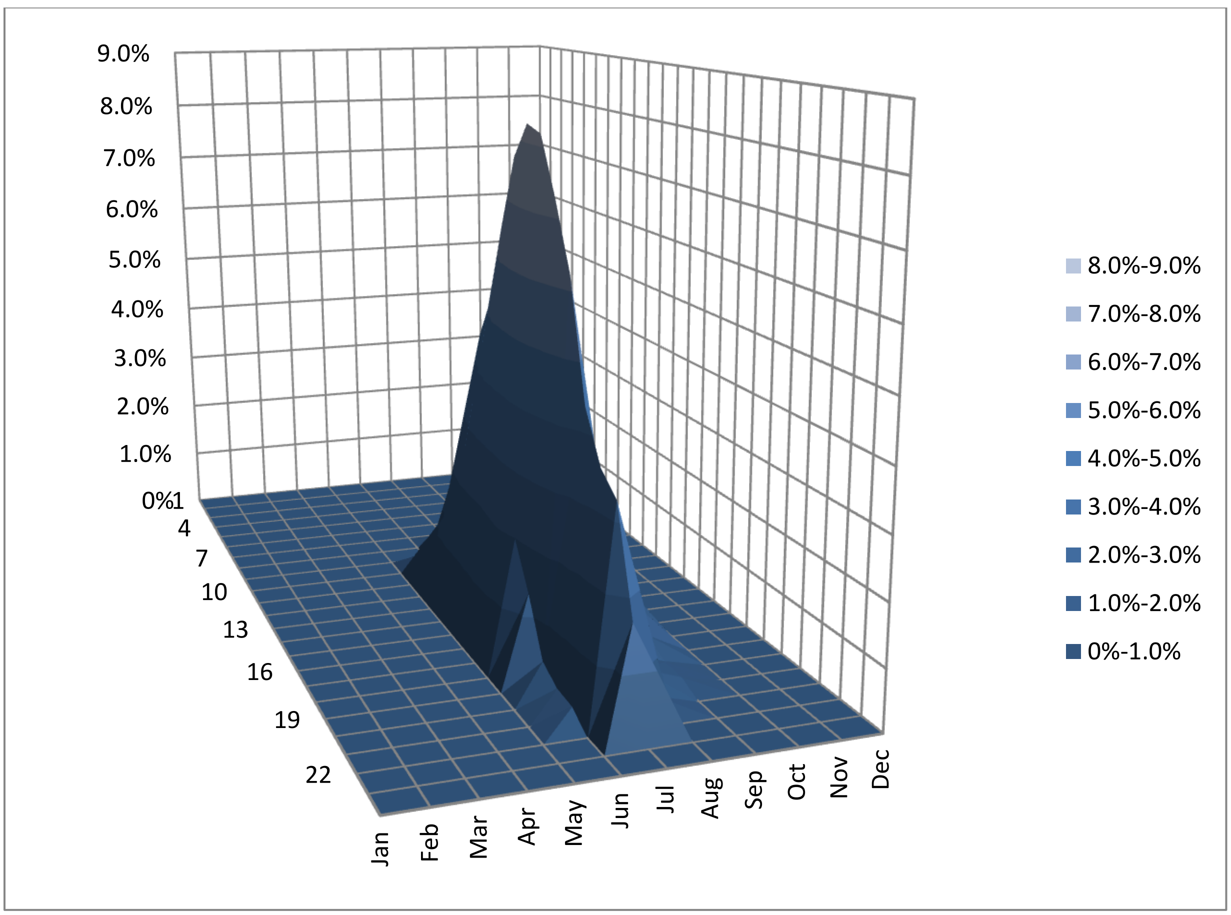
E.4 Tier 1 – Day Peak – High Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	1%	3%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	2%	6%	2%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	3%	8%	3%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	3%	8%	3%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	3%	8%	3%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	3%	8%	3%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	3%	7%	3%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	2%	5%	2%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



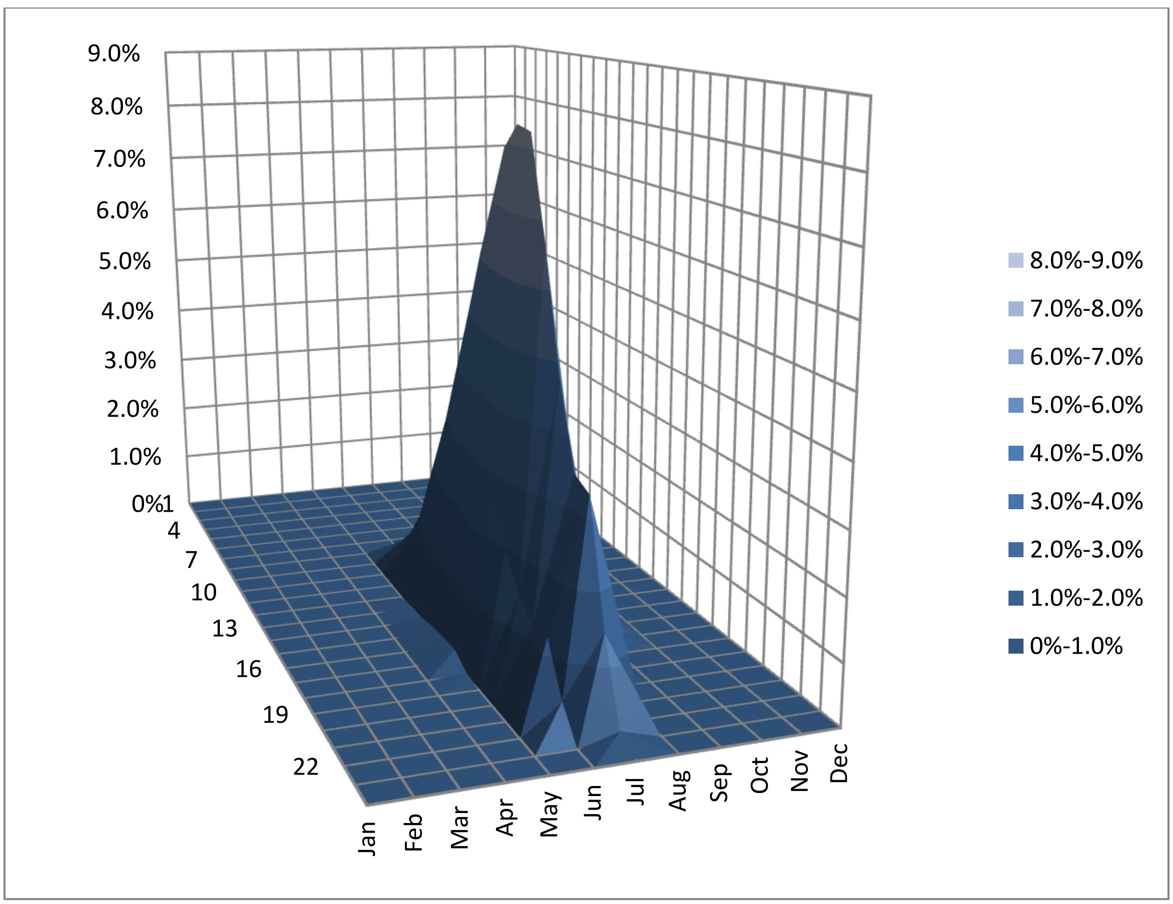
E.5 Tier 1 – Other – Low Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	2%	5%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	2%	7%	1%	1%	0%	0%	0%
14	0%	0%	0%	0%	0%	2%	8%	1%	1%	0%	0%	0%
15	0%	0%	0%	0%	0%	2%	8%	2%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	2%	8%	2%	1%	0%	0%	0%
17	0%	0%	0%	0%	0%	2%	7%	1%	1%	0%	0%	0%
18	0%	0%	0%	0%	0%	1%	6%	1%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



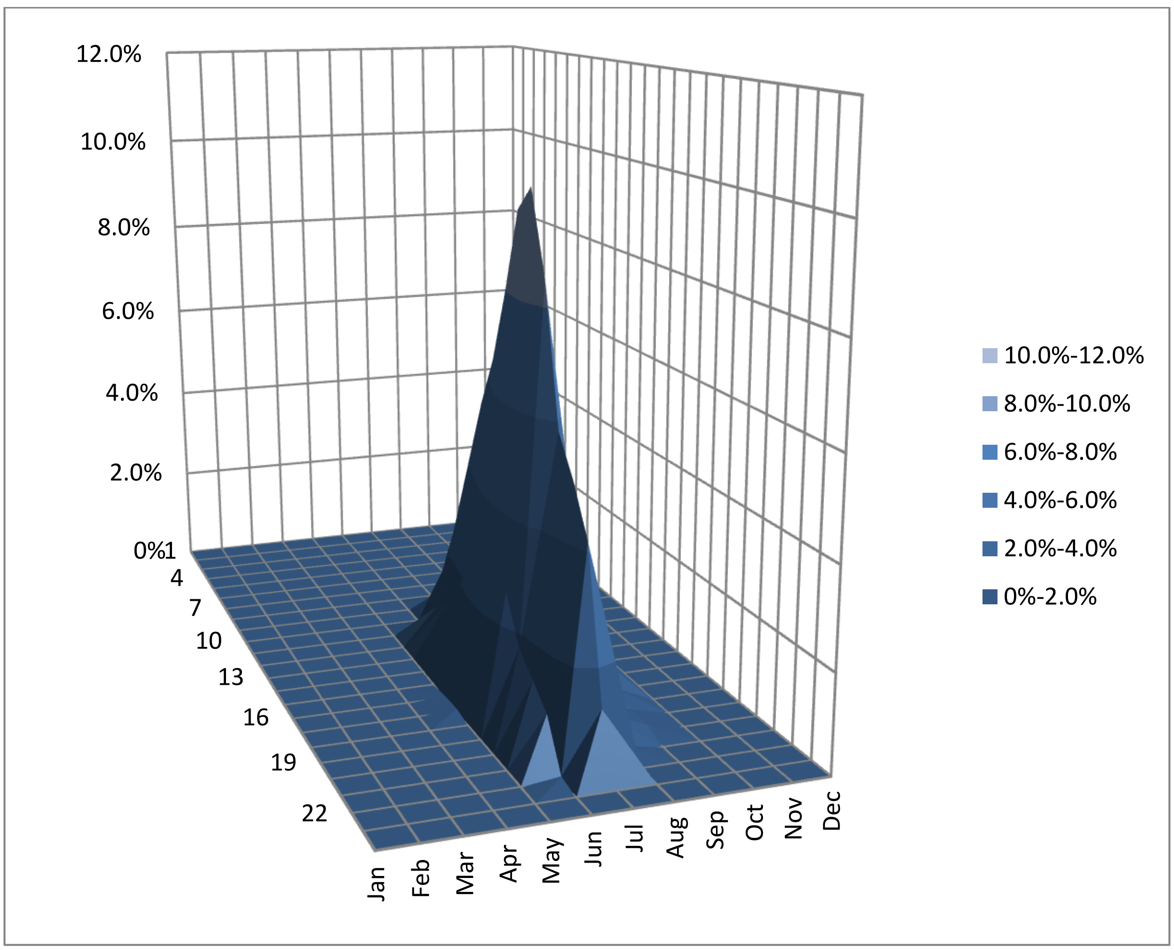
E.6 Tier 1 – Other – High Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	2%	5%	1%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	2%	6%	1%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	2%	7%	1%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	2%	8%	1%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	3%	8%	1%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	3%	8%	1%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	2%	7%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



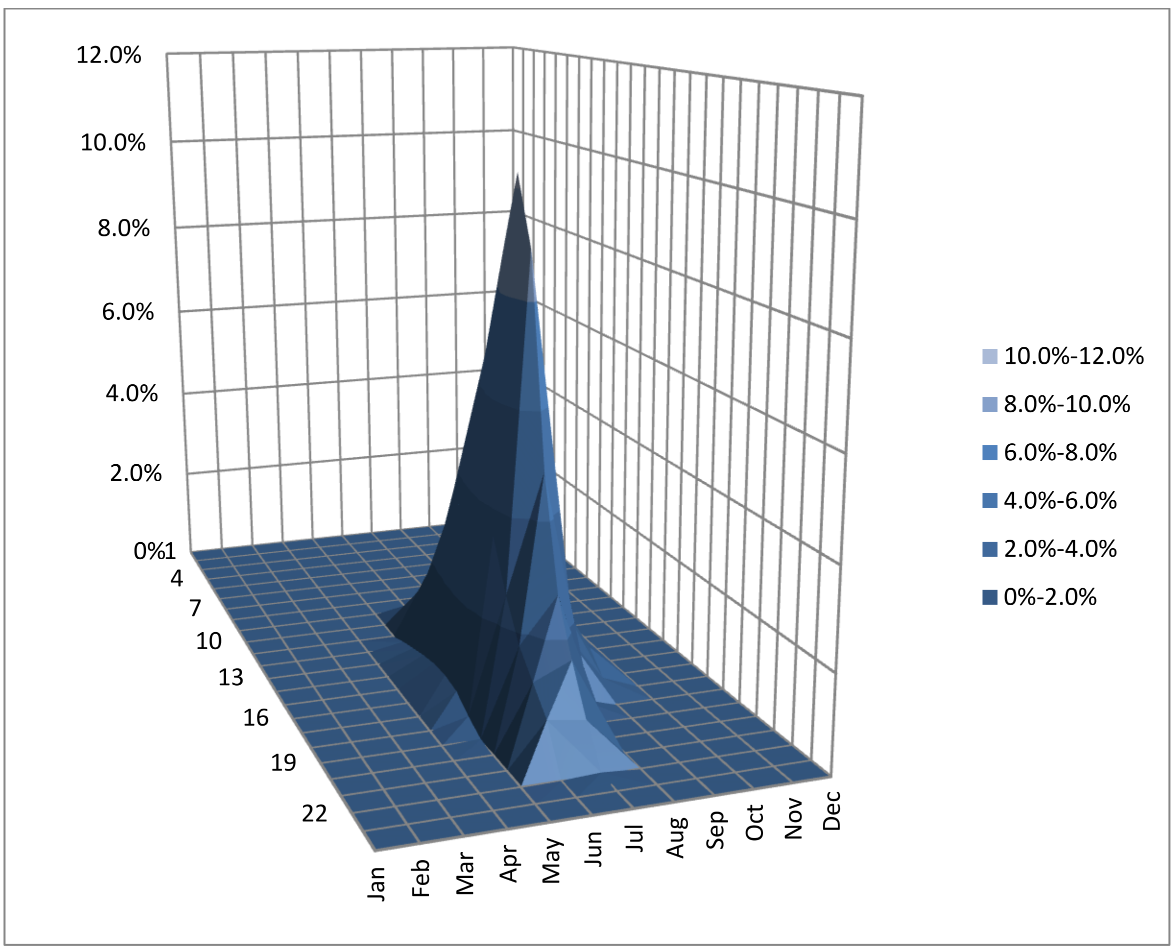
E.7 Radial – Low Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	2%	6%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	3%	8%	1%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	3%	10%	1%	1%	0%	0%	0%
17	0%	0%	0%	0%	0%	3%	10%	1%	1%	0%	0%	0%
18	0%	0%	0%	0%	0%	3%	9%	1%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	2%	6%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



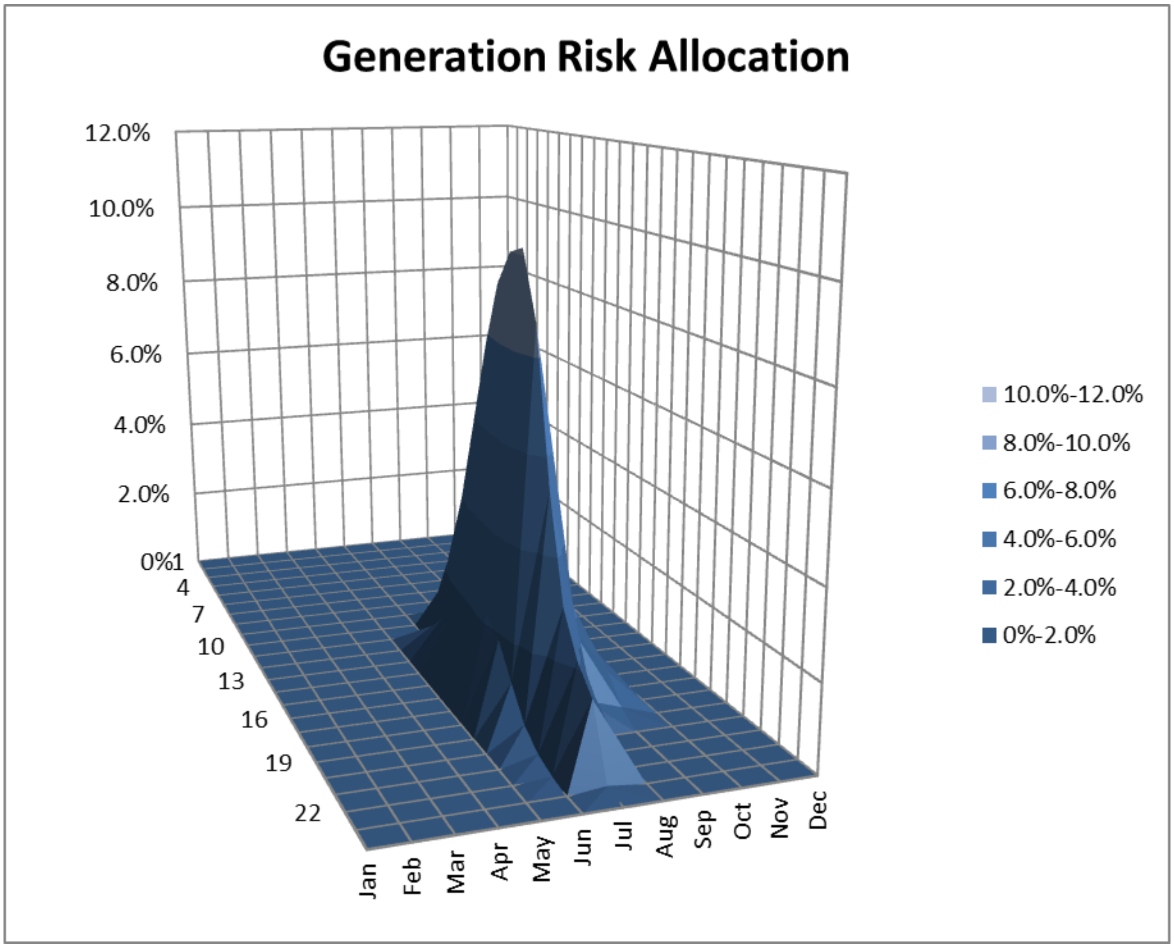
E.8 Radial – High Excess Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	2%	4%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	3%	6%	1%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	3%	7%	1%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	4%	9%	2%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	4%	10%	2%	1%	0%	0%	0%
17	0%	0%	0%	0%	0%	4%	9%	1%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	3%	5%	0%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	2%	3%	0%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



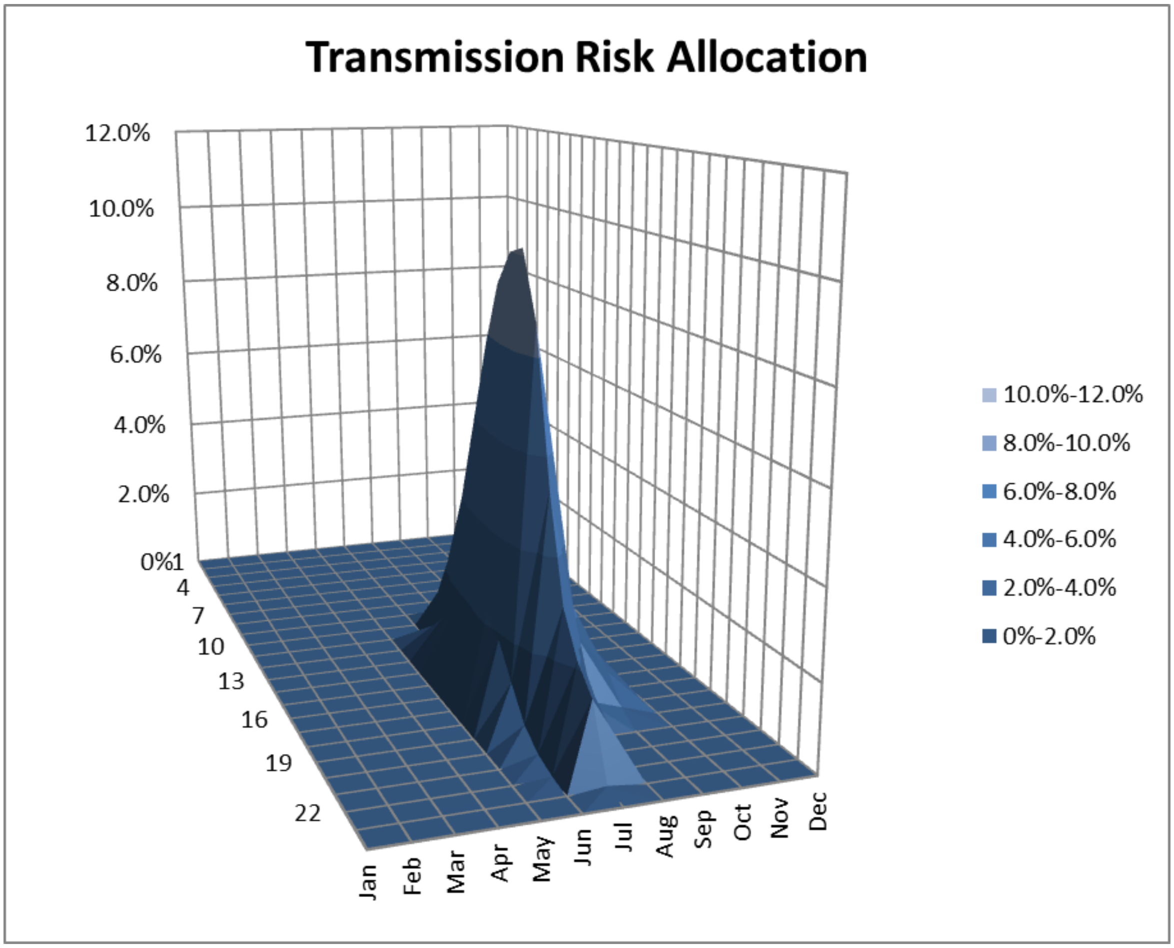
E.9 Generation Risk Allocation (NYISO Peaking Conditions)

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	1%	8%	2%	1%	0%	0%	0%
15	0%	0%	0%	0%	0%	2%	9%	2%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	2%	10%	3%	1%	0%	0%	0%
17	0%	0%	0%	0%	0%	2%	10%	3%	1%	0%	0%	0%
18	0%	0%	0%	0%	0%	2%	9%	2%	1%	0%	0%	0%
19	0%	0%	0%	0%	0%	1%	5%	1%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



E.10 Transmission Risk Allocation

Hour	January	February	March	April	May	June	July	August	September	October	November	December
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
13	0%	0%	0%	0%	0%	1%	5%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	1%	8%	2%	1%	0%	0%	0%
15	0%	0%	0%	0%	0%	2%	9%	2%	1%	0%	0%	0%
16	0%	0%	0%	0%	0%	2%	10%	3%	1%	0%	0%	0%
17	0%	0%	0%	0%	0%	2%	10%	3%	1%	0%	0%	0%
18	0%	0%	0%	0%	0%	2%	9%	2%	1%	0%	0%	0%
19	0%	0%	0%	0%	0%	1%	5%	1%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%



Transmission Risk Allocation
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0%
1
4
7
10
13
16
19
22
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
10.0%-12.0%
8.0%-10.0%
6.0%-8.0%
4.0%-6.0%
2.0%-4.0%
0%-2.0%

Appendix F Standardized Demand Reductions

This section describes the process used to standardize the demand reduction performance estimates used for the cost-effectiveness analysis. Standardization is required for several reasons. The demand reduction estimates used are grounded on performance during historical events. However, DR resources dispatched for historical events do not always reflect the full reduction capability of the program. They reflect the conditions and needs for resources at that time as well as procedural dispatch rules. CECONY often time dispatches resources locally and activates a fraction of overall resources. Different customers experience a different number of curtailment events, start times and event durations. The start hour and event duration can also vary from event-to-event for the same set of customers. In addition, resources are dispatched for under different conditions. Peaking conditions when resources are needed most tend to be extremely hot days. However, two of CECONY's programs – DLRP and DLC – are activated procedurally and can be dispatched under conditions other than those that drive network peaks and need for additional distribution, transmission and generating capacity.

The process for standardizing event performance varies for large customer (DLRP and CSRP and mass market programs and pilots (DLC and CoolNYC). For DLRP and CSRP, the emphasis is on the extent to which customers comply with pledged demand reductions. For DLC and CoolNYC, both of which are premised on control of air conditioners, demand reductions are produced for peaking conditions – that is, days when the forecasted system load for CECONY is projected to be 96% or more of the projected 1-in-2 annual peak. This is done because air conditioner loads are highly sensitive to weather and, typically, load control can reduce more demand when conditions are hotter and reductions are needed most. Despite these differences, the process has many similar steps:

1. *Use the available historical data*. The historical data used varies by program or pilot. For DLRP and CSRP, the 2012 performance during events is employed. For DLC, we relied on both 2011 and 2012 curtailment events because the data was available and few events met peaking condition criteria. For CoolNYC, we relied on 2013 event data because it was available and because peaking conditioners were met multiple times leading a number of curtailment events.
2. *Determine which events are included for standardized conditions*. For DLRP and CSPR all events are used since those programs are based on performance relative to pledged reductions. For DLC and CoolNYC, only events that meet peaking criteria are used to develop the estimate of the reference loads – that is, participant loads in the absence of curtailment – but all of the events are used to assess the consistency of percent demand reductions and explore how they vary based on start time, hours into the event, hour of day and overall loads absent curtailment (based on the control groups). For all programs, events where a larger amount of resources were activated are weighed more heavily than those where fewer resources were activated.
3. *Produce standardized reductions for multiple durations and start times*. The historical data is used to understand performance for events lasting four, five, six and eight hours. The durations were not extended beyond eight hours because of the limited empirical data for events lasting longer than eight hours. Technically, several programs can be called for a longer duration, if needed. For CSRP and CoolNYC, we also created a scenario that reflects current dispatch practices: events that last five hours and start either at 12 PM or 5 PM – depending on whether the network is classified as day or evening peaking. At this stage, the constraint that DLR P and CSRP cannot be activated between 11 PM and 6 AM was also included. CECONY's other programs and pilots do not have such constraints.
4. *Determine the optimal start times.* For each network group and event duration length, the optimal start time given the concentration of peaking risk is estimated. This reflects the

current dispatch practice for DLRP and DLC, which are dispatched when needed as long as needed. The flexible start times are included for CSRP and CoolNYC to allow an assessment of how changing current practices would affect value. For CRSP and CoolNYC, the cost-effectiveness base scenarios are based on the current practice of curtailment events that last five hours and start either at 12 PM or 5 PM depending on whether the network is day or evening peaking.

The remainder this Appendix provides additional details regarding the historical event data used, the process employed to standardize reductions and the standardized reductions by network type and hour of day. The large customer programs – DLRP and CSRP – are discussed first, followed by mass market options – Residential DLC, Small Business DLC and CoolNYC.

F.1 DLRP Impact Analysis

In 2012, DLRP was activated 16 distinct times on 9 different days. However, 15 of the curtailment events were activations targeting specific networks. All DLRP resources were jointly dispatched only once, on June 22, for a test event that lasted one hour. However, reductions were sustained well beyond the curtailment period, a pattern that is evident across other events. Aside from the test event, resources in nine Tier 2 networks and five Tier 1 networks were dispatched in response to contingency events. DLRP resources on three of the networks were dispatched on multiple event days.

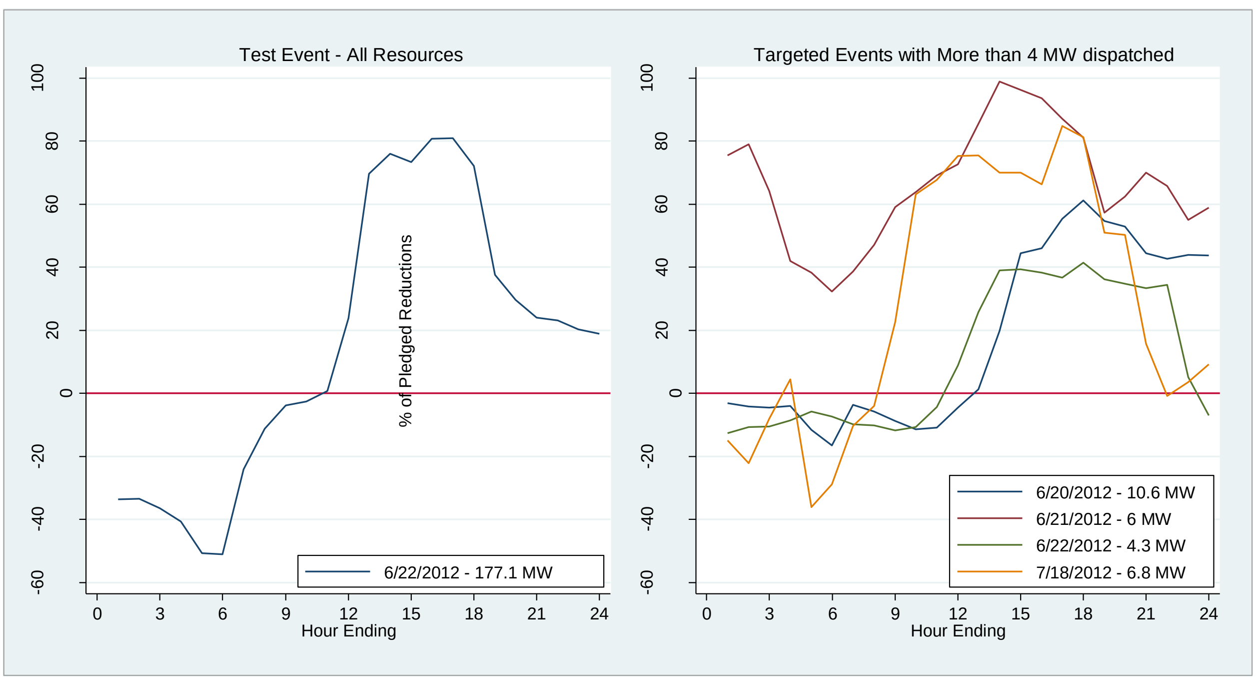
Table F-1 summarizes the 2012 DLRP events and includes information about the share of resources dispatched, event start times, duration and number of networks activated. There was wide variation in the magnitude of resources dispatched, event start times and event durations. During the test event, all 177 MW enrolled in DLRP's mandatory option were dispatched. Aside from the test events, dispatched DLRP resources varied from 1.6 MW to 10.6 MW of pledged reductions. Curtailment events started as early as 7 AM and as late as 9 PM. The event durations also varied ranging from five hours up to a single network that curtailed for nine continuous hours.

Figure F-1 shows the hourly reductions by event. The left side summarizes the results from the test event when all resources were activated. The right side summarizes reductions from the targeted curtailment events when more than 5 MW of pledged reductions were dispatched. It reflects the variation in event start times and durations. Most customers only had performance data for the test event. In 2012, less than 25% of DLRP mandatory resources (based on pledged reductions) experienced events other than the test events. This pattern is not unexpected since contingency conditions are rare by design. However, the limited number of activations also limits the ability to determine whether customers perform reliably across events and whether performance varies based on duration, start time and other factors.

Table F-1: 2012 DLPR Event Summary

Date	Networks activated	Accounts Activated	Event Start	Event duration (hours)	Pledged Reduction (MW)	Baseline (MW)	Estimated Reductions (MW)	Percent reductions (%)	Performance (%)
6/20/2012	3	43	17:00	7	10.6	38.7	5.2	13.5%	49.1%
6/20/2012	1	19	17:00	8	1.9	7.6	0.6	8.4%	34.3%
6/20/2012	1	14	18:00	8	2.0	2.5	1.0	40.2%	49.0%
6/21/2012	1	21	8:00	7	6.0	14.6	4.6	31.8%	77.9%
6/21/2012	1	20	20:00	7	1.9	1.3	0.1	11.4%	7.7%
6/21/2012	1	7	21:00	7	2.3	4.8	1.8	37.9%	80.9%
6/22/2012	1	9	7:00	7	1.6	3.4	0.8	24.1%	51.4%
6/22/2012	**68**	**684**	**12:00**	**1**	**177.1**	**880.5**	**123.2**	**14.0%**	**69.6%**
6/22/2012	1	17	17:00	5	4.3	5.6	1.6	27.8%	36.0%
7/4/2012	1	9	21:00	5	1.6	3.0	0.3	8.9%	16.6%
7/5/2012	1	9	15:00	5	1.7	7.6	0.3	3.4%	15.0%
7/16/2012	1	16	13:00	8	2.4	31.6	0.6	1.9%	25.3%
7/18/2012	1	21	7:00	8	6.8	42.8	3.8	8.8%	55.0%
7/18/2012	1	12	17:00	8	2.1	2.8	1.4	48.7%	66.0%
8/2/2012	1	11	12:00	5	1.9	4.3	0.5	10.8%	23.7%
9/16/2012	2	17	10:00	9	3.4	5.9	-0.2	-3.1%	-5.6%

Figure F-1: 2012 Hourly Load Reductions by Event



The first step in standardizing DLRP demand reductions involved calculating average reduction from past events on a customer-by-customer basis. This step was necessary because different customers experienced a different number of events. By calculating average reductions by customer first, we avoid over or under weighting any single customer. The demand reductions were estimated by taking the difference between a customer's baseline load (CBL) and actual loads during the event. This process was also applied to pre-event and post-event hours in order to account for any load shifting or snapback that occurs as a result of a DLRP event. However, over 75% of customers were only dispatched for the single-hour test event. It was not possible to assess if demand reductions for these customers vary over the course of longer events; the assumption is that their performance during longer events will be similar to their performance during the test event hour.

Next, the average reductions before, during and after events for each network group were aggregated. The demand reductions were then divided by the pledged reductions. In other words, all values were normalized and presented as percentage of pledged reductions.

The normalized reductions were then used to produce standardized reductions for multiple durations and start times. This was accomplished by creating reductions scenarios with different start times and durations to which pre-event, event and post-event normalized reductions were applied. For the four hours before the event, we applied the normalized reduction on an hour-by-hour basis, as a percentage of the pledged reductions. As a result, the reductions in the hour immediately prior to the event are different than reduction two or three hours prior to the event. For the event periods, we also applied the performance observed during first event hour, second event hour and so forth. Some customers did not experience long events, in which case, the performance during the average event hour was applied to those periods.[53] The same process was applied to periods after events in order to reflect any spillover of reductions or load shifting to hours after the event.

The final step was to identify the optimal start times for each network group and event duration scenario. To do this, the standardized reductions were combined with concentration of peaking risk, as described in Section 4.3, to produce an estimate of load carrying capacity. Table F-2 summarizes the standardized reduction used for the cost-effectiveness analysis. Because DLRP can be activated when needed as long as needed (except for the time period of 11 PM to 6 AM), these estimates are based on an eight-hour event duration.

Table F-2 summarizes the standardized reductions per hour used for the cost-effectiveness analysis by network group. Since DLRP participants pledge specific amounts of demand reductions, the values in the table are the percent of the pledged reductions delivered. A positive value indicates a demand reduction and a negative indicates a load increase.

[53] For example, in constructing an eight hour scenario for a customer that only had experienced events lasting five hours, the performance factor for hours, six, seven and eight was simply the average of the five hours where we had historical performance data.

Table F-2: Standardized Performance Factors By Network Group (Eight-hour Event)

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	-24.9%	29.4%	-78.8%	-74.2%	-6.2%	-34.5%	-41.4%	-3.5%
2	-27.0%	22.7%	-99.6%	-80.5%	-5.1%	-38.4%	-43.2%	-7.3%
3	-25.9%	28.3%	-135.4%	-98.2%	-5.3%	-37.9%	-50.7%	-6.8%
4	-27.9%	25.7%	-118.0%	-100.9%	-8.4%	-30.9%	-44.9%	-7.1%
5	-23.5%	26.4%	-72.6%	-47.9%	-2.1%	1.8%	-53.8%	-5.2%
6	-9.3%	25.2%	-51.8%	-26.0%	3.3%	12.5%	-48.4%	-7.3%
7	-7.5%	35.3%	-38.2%	-17.7%	7.4%	21.1%	-38.7%	-8.5%
8	0.2%	36.8%	-45.6%	-15.6%	11.1%	20.5%	-35.2%	-6.7%
9	6.0%	40.5%	-44.2%	-13.9%	12.8%	21.4%	-16.1%	-3.5%
10	19.7%	48.9%	-13.8%	7.4%	38.4%	34.4%	17.1%	16.3%
11	43.2%	79.1%	34.9%	56.4%	72.3%	78.1%	86.2%	42.5%
12	40.7%	66.3%	40.0%	56.4%	70.2%	76.5%	86.2%	42.5%
13	41.6%	69.1%	53.4%	56.4%	70.1%	75.9%	86.2%	42.5%
14	41.7%	70.5%	55.9%	56.4%	69.8%	74.7%	86.2%	42.5%
15	38.5%	76.9%	58.9%	56.4%	70.1%	73.6%	86.2%	42.5%
16	38.5%	76.9%	58.9%	56.4%	70.1%	73.6%	86.2%	42.5%
17	38.5%	76.9%	58.9%	56.4%	70.1%	73.6%	86.2%	42.5%
18	38.5%	76.9%	58.9%	56.4%	70.1%	73.6%	86.2%	42.5%
19	41.0%	85.6%	63.3%	58.2%	79.5%	86.1%	94.1%	52.5%
20	41.6%	79.8%	64.7%	61.7%	68.5%	90.6%	87.9%	52.7%
21	49.3%	79.3%	73.8%	77.6%	72.5%	92.9%	100.2%	54.4%
22	46.8%	69.5%	80.3%	80.8%	70.3%	92.1%	95.8%	54.1%
23	49.5%	63.7%	70.3%	66.6%	65.3%	83.6%	89.3%	53.7%
24	13.9%	16.5%	11.5%	34.1%	32.1%	22.1%	19.1%	22.2%

There are several noteworthy observations. The event performance varies by network group. The process implicitly assumes that performance in the future will be similar to past performance. In addition, event start times vary by network group. A third observation is for most networks, customers continue to deliver reductions after the conclusion of an event. This pattern was observed during actual events but was most pronounced during the test event. Lastly, on several of the network groups, customers increase load during pre-event hours. If the load shifting coincides with the peak loads on the network, these load increases can produce a negative value. The load shifting behavior and its coincidence with peaking conditions is accounted for in the cost-effectiveness analysis.

F.2 CSRP Impact Analysis

In 2012, there were only four CSRP events, two daytime events and two evening events. Although there were very few events, the events were called over many networks allowing for the estimation of event performance factors for each network type except for the *Radial – High Excess* group, which lacks any CSRP participants. Because CSRP events can only occur between 12 and 5 PM for day peaking networks and between 5 and 10 PM for evening peaking networks, a set of fixed impacts were calculated for those hours only. A flexible option was included as well, just as it was included for CoolNYC. The flexible option allows for varying event durations and event start times.

In 2012, CSRP was activated four distinct times on two different days. Each of these events was called over the entirety of Zone J, which covers New York City. Each of the event days had a daytime event from 12–5 PM and an evening event from 5–10 PM. As seen with DLRP, reductions were sustained well beyond the curtailment period.

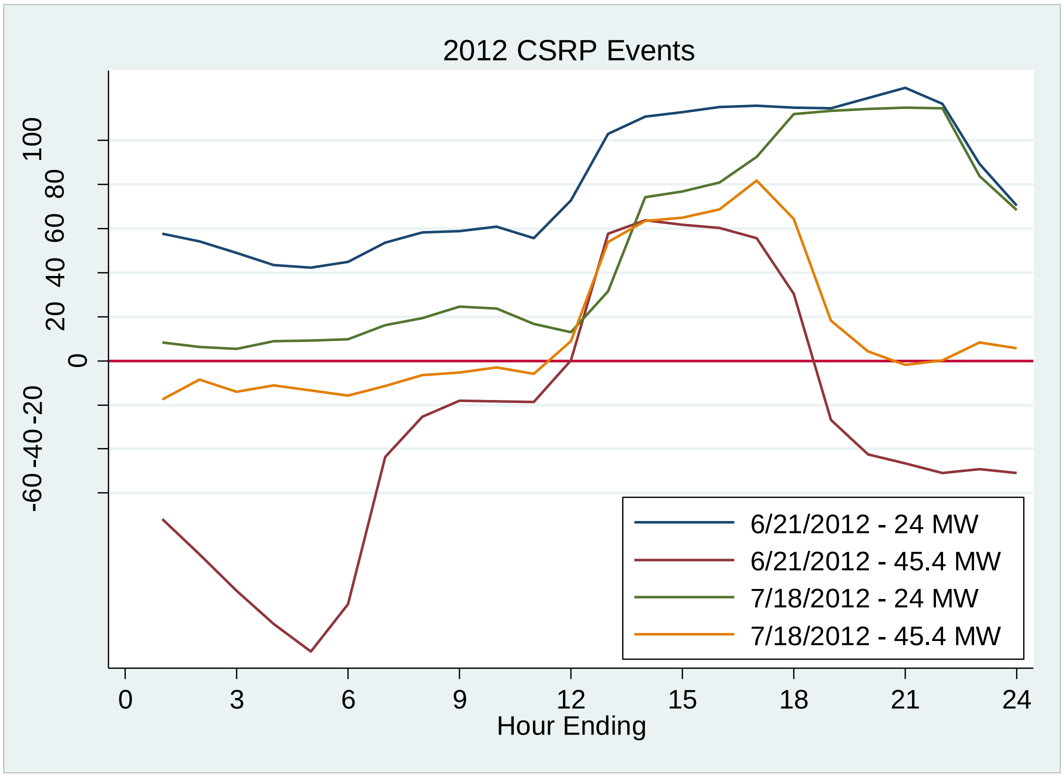
Table F-3 summarizes the 2012 CSRP events and includes information about the share of resources dispatched, event start times, duration and number of networks activated. There was no variation in the magnitude of resources dispatched, event start times and event durations – the two event days were identical in this regard. During both events, approximately 45 MW enrolled in CSRP's mandatory option were dispatched during the day and 24 MW were dispatched in the evening.

Figure F-2 shows the hourly reductions by event. It reflects the limited variation in event start times and durations. The limited number of activations also limited the ability to determine whether customers performed reliably across events and whether performance varied based on duration, start time and other factors.

Table F-3: 2012 CSRP Event Summary

Date	Networks Activated	Accounts Activated	Event Start	Event Duration (hours)	Pledged Reduction (MW)	Baseline (MW)	Estimated Reductions (MW)	Percent Reductions (%)	Performance (%)
6/21/2012	29	172	12:00	5	45.42	321.9	27.2	8.44%	59.83%
6/21/2012	20	64	17:00	5	23.99	63.9	28.3	44.26%	117.88%
7/18/2012	29	172	12:00	5	45.42	329.8	30.2	9.17%	66.56%
7/18/2012	20	64	17:00	5	23.99	51.0	27.3	53.59%	113.91%

Figure F-2: 2012 Hourly Load Reductions by Event



The steps for converting historical CSRP event performance into standardized reductions are identical those for DLRP, which were described earlier. The main difference is that for CSPR, the standardized reductions reflect a fixed five hour event window, lasting from 12-5 PM or from 5-10 PM, depending on whether the customers was located on a network classified as day or evening peaking. The fixed five hour event window reflects current program rules. We also created scenarios that assumed the event start times and duration could vary to facilitate sensitivity analysis.

Tables G-4 and G-5 summarize the standardized reductions per hour used for the cost-effectiveness analysis by network group. Since CSRP participants pledge specific amounts of demand reductions, the values in the table are the percent of the pledged reductions delivered. A positive value indicates a demand reduction and a negative indicates a load increase. There are several noteworthy observations. The event performance varies by network group. The process implicitly assumes that performance in the future will be similar to past performance. A second observation is for most networks, customers continue to deliver reductions after the conclusion of an event. This pattern was observed during actual events but was most pronounced during the test event. Lastly, on several of the network groups, customers increased load during pre-event hours. If the load shifting coincides with the peak loads on the network, these load increases can produce negative value. The load shifting behavior and its coincidence with peaking conditions is accounted for in the cost-effectiveness analysis. For the flexible option, event start times vary by network group.

Table F-4: Standardized Performance Factors by Network Group (Fixed Five-hour Event)

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	-37.2%	52.6%	-64.1%	-38.4%	29.4%	-46.4%	-9.9%	-16.3%
2	-36.7%	49.6%	-72.5%	-40.3%	27.5%	-51.9%	-11.0%	-19.3%
3	-36.7%	38.8%	-88.1%	-47.8%	26.3%	-72.0%	-10.3%	-27.1%
4	-37.2%	33.3%	-90.3%	-57.9%	28.5%	-78.1%	-10.6%	-30.3%
5	-35.3%	31.4%	-124.4%	-60.3%	29.7%	-74.4%	-8.2%	-34.5%
6	-41.8%	30.0%	-138.7%	-38.6%	27.6%	-52.2%	-1.6%	-30.7%
7	-35.5%	30.8%	-60.8%	-12.8%	35.2%	-22.0%	-2.4%	-9.7%
8	-29.1%	34.3%	-32.5%	-9.5%	39.0%	-4.1%	-1.2%	-0.4%
9	-29.1%	38.7%	-28.9%	-6.0%	41.7%	5.7%	-5.1%	2.4%
10	-29.3%	40.4%	-24.8%	-4.9%	45.1%	-4.5%	-1.5%	2.9%
11	-25.7%	40.0%	-31.9%	-5.8%	41.8%	-13.9%	1.2%	0.8%
12	-9.9%	43.3%	-12.9%	7.5%	54.9%	-1.5%	-4.6%	11.0%
13	35.0%	65.6%	40.3%	51.7%	79.9%	70.6%	39.4%	54.7%
14	48.6%	107.8%	50.0%	59.8%	89.0%	97.6%	84.8%	76.8%
15	47.6%	112.1%	49.6%	60.2%	90.0%	97.2%	79.1%	76.5%
16	49.2%	112.7%	52.0%	61.2%	93.8%	96.7%	86.8%	78.9%
17	53.2%	114.9%	64.1%	61.7%	100.6%	103.6%	88.1%	83.7%
18	56.4%	114.2%	44.0%	37.4%	104.9%	95.9%	91.3%	77.7%
19	20.5%	111.4%	-19.5%	-13.2%	98.6%	65.3%	86.2%	49.9%
20	0.2%	125.4%	-24.3%	-26.2%	95.5%	42.9%	43.6%	36.7%
21	-11.0%	132.7%	-38.9%	-27.4%	96.7%	41.8%	43.8%	34.0%
22	-16.6%	125.4%	-46.8%	-23.0%	95.2%	32.1%	31.7%	28.3%
23	-19.3%	100.6%	-40.9%	-16.2%	74.2%	12.9%	1.3%	16.1%
24	-23.8%	109.9%	-39.6%	-18.3%	51.9%	0.5%	2.2%	11.8%

Table F-5: Standardized Performance Factors by Network Group (Eight-hour Event)

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	-41.0%	33.3%	-88.1%	-47.8%	33.0%	-66.0%	-11.0%	-22.8%
2	-39.1%	31.4%	-90.3%	-57.9%	33.5%	-90.5%	-10.3%	-28.7%
3	-36.4%	30.0%	-124.4%	-60.3%	35.6%	-95.3%	-10.6%	-30.5%
4	-44.6%	30.8%	-138.7%	-38.6%	38.1%	-93.2%	-8.2%	-33.9%
5	-38.4%	34.3%	-60.8%	-12.8%	31.4%	-74.4%	-1.6%	-32.0%
6	-25.8%	38.7%	-32.5%	-9.5%	42.3%	-39.9%	-2.4%	-10.1%
7	-17.6%	40.4%	-28.9%	-6.0%	59.6%	17.7%	-1.2%	16.4%
8	-16.0%	40.0%	-24.8%	-4.9%	68.9%	73.8%	-5.1%	40.4%
9	-9.0%	43.3%	-31.9%	-5.8%	72.1%	60.6%	-1.5%	39.7%
10	7.3%	65.6%	-12.9%	7.5%	75.7%	60.5%	1.2%	41.3%
11	48.3%	107.8%	40.3%	51.7%	87.3%	87.4%	-4.6%	54.2%
12	55.0%	112.1%	50.0%	59.8%	109.0%	186.2%	39.4%	91.6%
13	50.3%	112.7%	49.6%	60.2%	114.2%	183.2%	84.8%	94.3%
14	49.9%	114.9%	52.0%	61.2%	114.8%	180.3%	79.1%	89.2%
15	53.5%	114.2%	64.1%	61.7%	117.4%	176.2%	86.8%	90.5%
16	53.5%	111.4%	64.1%	61.7%	117.6%	174.9%	88.1%	89.8%
17	53.5%	125.4%	64.1%	61.7%	117.6%	174.9%	91.3%	89.8%
18	53.5%	132.7%	64.1%	61.7%	117.6%	174.9%	86.2%	89.8%
19	52.5%	125.4%	44.0%	37.4%	117.6%	174.9%	43.6%	89.8%
20	14.0%	125.4%	-19.5%	-13.2%	90.5%	117.3%	43.8%	63.4%
21	-11.7%	125.4%	-24.3%	-26.2%	59.3%	53.5%	31.7%	29.5%
22	-21.3%	125.4%	-38.9%	-27.4%	0.4%	6.3%	31.7%	-11.1%
23	-26.9%	100.6%	-46.8%	-23.0%	-1.0%	8.0%	31.7%	-16.1%
24	-29.6%	109.9%	-40.3%	-17.3%	-1.9%	-1.6%	31.7%	-20.0%

F.3 DLC Impact Analysis

As described in Section 2, the CECONY DLC program reduces demand using direct load control devices that control air conditioning loads. In 2012 there were more than 20 DLC events for small business and residential customers each. These events were called over a variety of weather conditions and geographic regions. There was a wide variety of event start times and durations to work with in order to forecast possible event impacts. It is important to note that the majority of the DLC events called in 2012 were not test events, but were called either because of emergency conditions on specific networks or because CECONY's system load was approximating its projected peak. This historical data from a diversity of events allows for estimation of impacts for a variety of event conditions.

DLC demand reductions were standardized for peaking conditions – that is, days when the forecasted system load for CECONY is projected to be 96% or more of the projected 1-in-2 annual peak. It is peaking conditions that drive a large share of distribution capacity cost. Curtailment events that met peaking criteria are used to develop the estimate of the reference loads – that is, participant loads in the absence of curtailment. However, all events are used to assess the consistency of percent demand reductions and explore how they vary based on start time, hours into the event, hour of day and overall loads absent curtailment (based on the control groups).

Table F-6 shows the hourly reductions by event for the business component of DLC. It reflects the variation in event start times and durations. It also presents how drastic differences in the number of networks called occur between events. Table F-7 shows the same information for the residential component. Both Residential and Small Business DLC estimates relied on 20 events. However, CECONY dispatched all resources in only four days – July 21, 2011, June 20, 2012, July 6, 2012 and July 22, 2012. Two of those days, July 21, 2011 and July 22, 2012, met conditions that trigger peak shaving events and are in bold.

Table F-6: 2011 and 2012 Business DLC Event Summary

Date	Networks activated	Accounts Activated	Event Start	Event Duration (hours)	Baseline (kW)	Estimated Reductions (kW)	Percent Reductions (%)
7/21/2011	**83**	**6829**	**14:00**	**5**	**8.1**	**2.5**	**31%**
6/20/2012	83	6646	15:00	4	6.9	2.0	30%
6/20/2012	5	434	18:00	5	4.8	1.1	22%
6/22/2012	1	178	8:00	6	2.9	1.0	35%
6/29/2012	6	6591	14:00	5	6.2	1.8	29%
7/6/2012	70	6861	17:00	1	6.9	2.6	38%
7/17/2012	24	1046	16:00	5	3.3	1.0	31%
7/17/2012	4	555	18:00	5	2.4	0.6	26%
7/17/2012	8	1053	19:00	5	2.0	0.6	29%
7/18/2012	35	1783	13:00	6	3.8	1.1	28%
7/18/2012	24	3826	14:00	5	3.8	1.1	29%
7/18/2012	10	1004	15:00	4	3.5	0.9	26%
7/18/2012	3	256	18:00	5	2.1	0.7	35%
7/22/2012	**70**	**5663**	**13:00**	**6**	**4.4**	**1.4**	**32%**
7/22/2012	**9**	**1166**	**14:00**	**5**	**4.5**	**1.3**	**28%**
8/2/2012	1	56	13:00	5	3.7	0.8	22%

Table F-7: 2011 and 2012 Residential DLC Event Summary

Date	Networks Activated	Accounts Activated	Event Start	Event Duration (Hours)	Baseline (kW)	Estimated Reductions (kW)	Percent Reductions (%)
7/21/2011	**83**	**21027**	**14:00**	**5**	**5.9**	**2.3**	**39%**
6/20/2012	83	14952	15:00	4	4.9	1.7	35%
6/20/2012	5	7016	18:00	5	5.4	1.5	28%
6/22/2012	1	321	8:00	6	1.8	0.6	33%
6/29/2012	6	15002	14:00	5	4.1	1.0	25%
7/6/2012	70	20413	17:00	1	4.7	1.7	36%
7/17/2012	24	507	16:00	5	2.0	0.8	38%
7/17/2012	4	539	18:00	5	2.0	0.6	31%
7/17/2012	8	1455	19:00	5	1.8	0.5	25%
7/18/2012	35	677	13:00	6	1.8	0.6	32%
7/18/2012	24	7302	14:00	5	2.3	0.8	36%
7/18/2012	10	7182	15:00	4	2.5	0.9	35%
7/18/2012	3	5479	18:00	5	2.0	0.6	30%
7/22/2012	**70**	**12804**	**13:00**	**6**	**3.1**	**1.2**	**37%**
7/22/2012	**9**	**8223**	**14:00**	**5**	**3.4**	**1.2**	**36%**
8/2/2012	1	51	13:00	5	1.6	0.3	17%

There were four intermediary steps in producing standardized reductions for DLC:

- *Estimate the air conditioner use during peaking conditions.* The process for doing this was straightforward. The air conditioner loads for the control group during the two days that met peaking criteria – 96% of more of CECONY peak load for planning – were simply averaged by hour.
- *Estimate how percent reductions and snapback varies* based on air conditioner loads absent curtailment, event start times, hour of day and number of hours into an event.
- *Create scenarios with different start times and durations.* This step was necessary to assess when reductions coincide most with the risk of peaking conditions.
- *Apply the percent reductions to air conditioner use during peaking conditions for each of the scenarios.* The percent reductions were estimated based on the event scenarios characteristics and the regression on historical data.

Figure F-3 presents the hourly air conditioner demand per units absent curtailment. The charts are based on the control group's air conditioner use during actual events. The plots on the left present demand per air conditioner during the two events that met peaking conditions. The average of these two days was used to produce the standardized impacts. The plots on the right reflect air conditioner loads during all other events, which were not necessarily on hot days, were specific to a network and had fewer participants. Not surprisingly, the air conditioner demand during emergency load relief events was lower. Another observation is that residential air conditioner use is more variable than that of small businesses.

Figure F-3: Air Conditioner Demand on Event Days (Control Group)

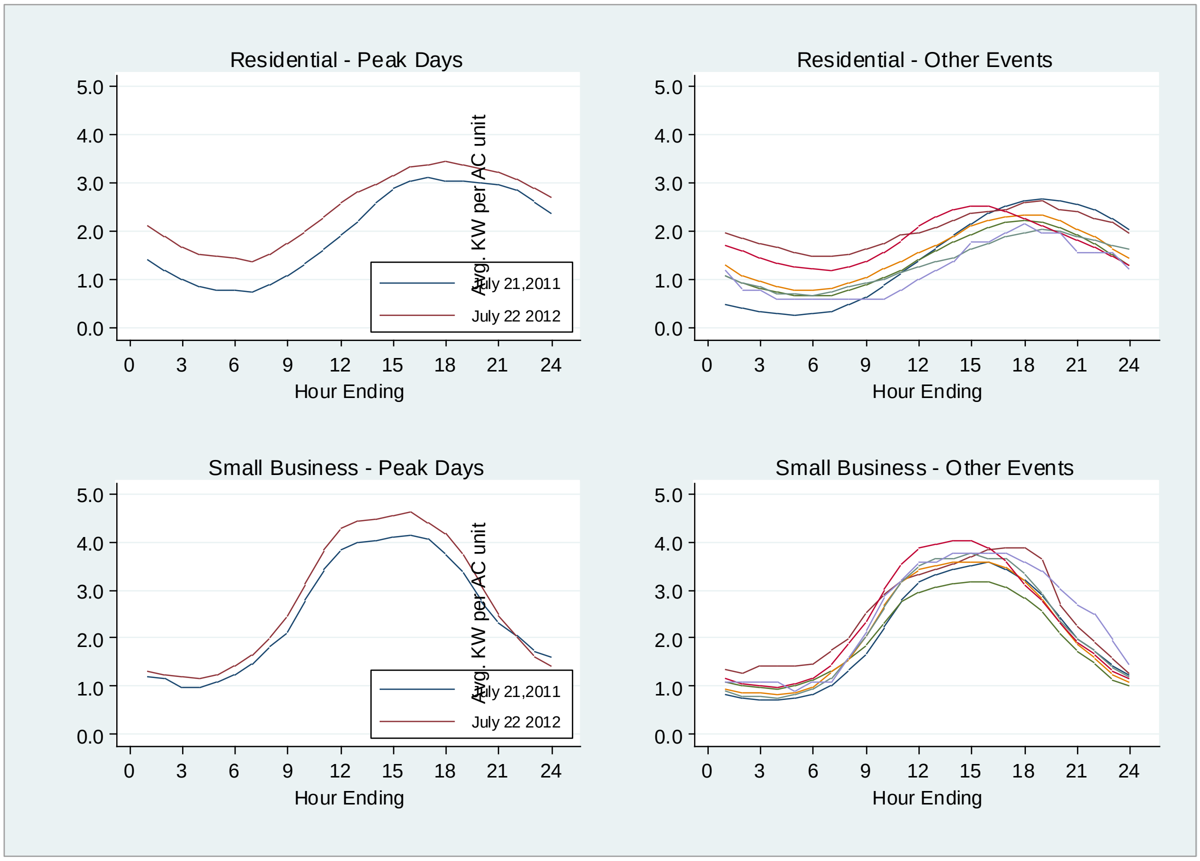
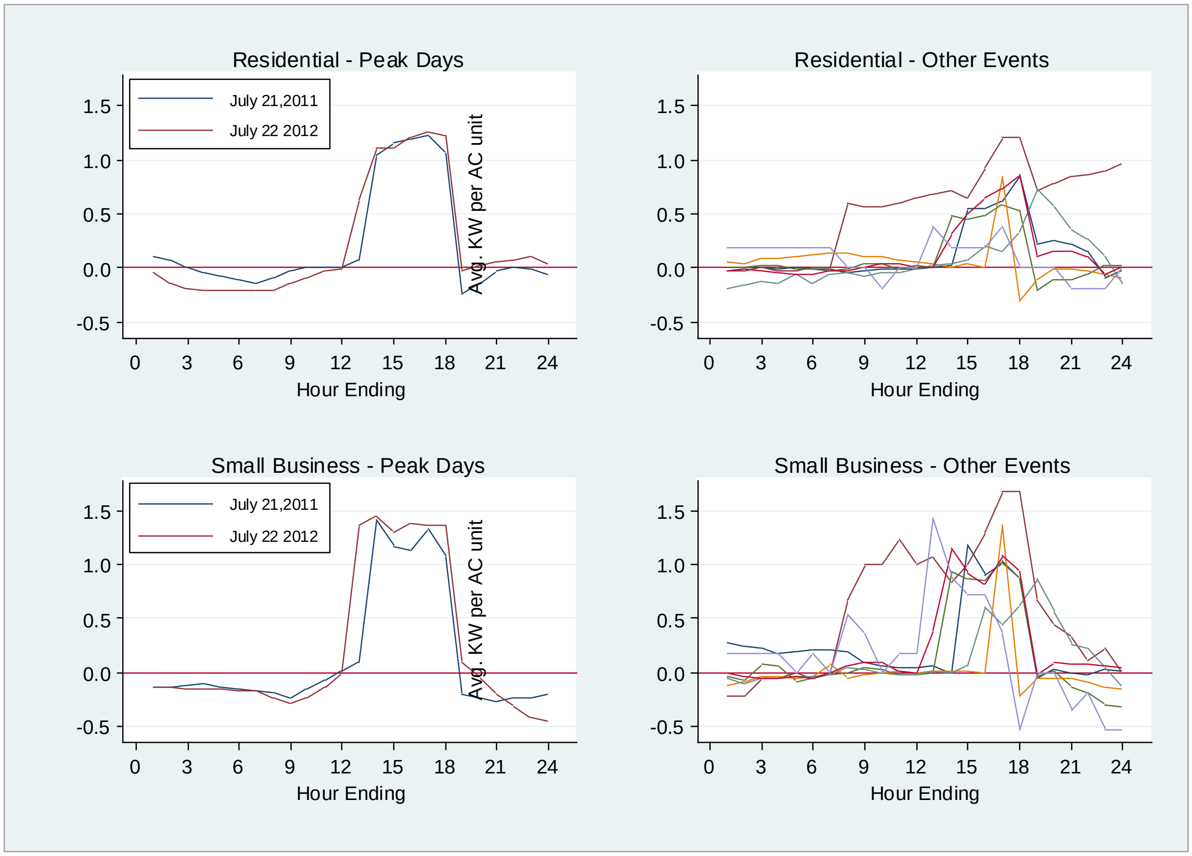


Figure F-4 follows the same format, but presents the estimated load reductions. Residential air conditioner demand reductions on the two days that met peaking conditions exceeded 1 kW throughout the event period. Small businesses reductions were also relatively constant throughout the curtailment period on the days that met peaking conditions, delivering reductions of approximately 1.3 kW. The reductions in response to emergency conditions vary substantially due to variation in start time, event length and the smaller number of devices under control. In addition, the graph presents reductions by date. For some dates it includes different networks were load control was active for different hours.

Figure F-4: Air Conditioner Demand Reductions During Events



As part of standardizing impacts, we estimated how percent reductions and snapback vary based on air conditioner loads absent curtailment, event start times, hour of day and number of hours into an event. All of the event days and event hours were used in the regression analysis since the primary goal was to understand variation in reductions. The dependent variable was the percent reduction in air conditioner use. Weights were applied so dates when more devices were sent control signals more so than days with fewer devices. In addition, a similar regression model was developed to estimate snapback after events. These steps were necessary because they allowed us to assess how reductions would vary if DLC events started at different time or curtailments were sustained for different periods of time. By design, the regression model was a predictive model and should not be used to infer causal conclusion. Tables G-8 and G-9 presents the residential regression results for event reductions and snapback. Tables G-10 and G-11 presents the small business regression models for percent reductions and snapback. The most notable pattern from this analysis is that percent reductions were higher when air conditioner demand was higher.

Table F-8: Residential DLC Regression Explaining Variation in Percent Reductions

Source	SS	df	MS
Model	1969.7126	23	85.6396783
Residual	1721.01655	73	23.5755691
Total	3690.72915	96	38.4450953

Number of obs =	97
F(23, 73) =	3.63
Prob > F =	0.0000
R-squared =	0.5337
Adj R-squared =	0.3868
Root MSE =	4.8555

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
kw_0perdevice	7.254937	1.208871	6.00	0.000	4.845661	9.664213
event_start						
13	.2049472	20.18221	0.01	0.992	-40.01814	40.42803
14	.8358122	20.22803	0.04	0.967	-39.47859	41.15021
15	4.557974	20.25375	0.23	0.823	-35.80769	44.92364
16	14.30864	21.49427	0.67	0.508	-28.52938	57.14666
17	6.021828	20.40193	0.30	0.769	-34.63915	46.68281
18	6.325887	20.47259	0.31	0.758	-34.47593	47.12771
19	10.51885	21.0661	0.50	0.619	-31.46583	52.50352
hour						
9	-5.717289	28.19011	-0.20	0.840	-61.9001	50.46552
10	-8.214726	28.19094	-0.29	0.772	-64.39919	47.96973
11	-11.06848	28.19396	-0.39	0.696	-67.25896	45.12199
12	-8.60632	28.19464	-0.31	0.761	-64.79815	47.58551
13	-10.00788	28.19786	-0.35	0.724	-66.20612	46.19037
14	-10.16751	28.42965	-0.36	0.722	-66.82772	46.49269
15	-14.74234	28.4313	-0.52	0.606	-71.40583	41.92115
16	-15.25226	28.43864	-0.54	0.593	-71.9304	41.42588
17	-13.59862	28.44169	-0.48	0.634	-70.28283	43.0856
18	-16.34985	28.44203	-0.57	0.567	-73.03474	40.33504
19	-22.79895	28.7504	-0.79	0.430	-80.09841	34.50051
20	-23.51346	28.74704	-0.82	0.416	-80.80623	33.77931
21	-24.01244	28.75407	-0.84	0.406	-81.31922	33.29434
22	-29.85656	28.74937	-1.04	0.302	-87.15397	27.44085
23	-32.88503	30.48103	-1.08	0.284	-93.63365	27.86358
eventhour	0	(omitted)				
_cons	27.70099	20.01837	1.38	0.171	-12.19555	67.59754

Table F-9: Residential DLC Regression Explaining Snapback

Source	SS	df	MS
Model	644.987346	4	161.246837
Residual	1364.81483	83	16.4435521
Total	2009.80217	87	23.1011744

Number of obs =	88
F(4, 83) =	9.81
Prob > F =	0.0000
R-squared =	0.3209
Adj R-squared =	0.2882
Root MSE =	4.0551

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
posteventhour						
2	4.789007	1.319417	3.63	0.000	2.164739	7.413275
3	6.286951	1.358708	4.63	0.000	3.584536	8.989366
4	6.898217	1.358708	5.08	0.000	4.195802	9.600632
5	7.212994	1.360402	5.30	0.000	4.507209	9.918778
_cons	-6.791942	.9301882	-7.30	0.000	-8.642049	-4.941835

Table F-10: Small Business DLC Regression Explaining Percent Reductions

Source	SS	df	MS
Model	1092.2577	23	47.489465
Residual	1037.33777	73	14.2101065
Total	2129.59547	96	22.1832861

Number of obs	=	97
F(23, 73)	=	3.34
Prob > F	=	0.0000
R-squared	=	0.5129
Adj R-squared	=	0.3594
Root MSE	=	3.7696

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
kw_0perdevice	.69368	1.052575	0.66	0.512	-1.404098	2.791458
event_start						
13	5.473273	12.76151	0.43	0.669	-19.96039	30.90693
14	5.684769	12.7723	0.45	0.658	-19.77038	31.13992
15	6.563498	12.79544	0.51	0.610	-18.93777	32.06476
16	9.644709	13.05646	0.74	0.462	-16.37677	35.66619
17	13.34175	12.94315	1.03	0.306	-12.45392	39.13742
18	8.764132	13.27294	0.66	0.511	-17.6888	35.21706
19	15.15164	13.53188	1.12	0.267	-11.81735	42.12064
hour						
9	6.315923	17.79763	0.35	0.724	-29.1547	41.78655
10	.6585148	17.81481	0.04	0.971	-34.84636	36.16339
11	4.44477	17.83296	0.25	0.804	-31.09627	39.98581
12	-3.721192	17.84159	-0.21	0.835	-39.27942	31.83704
13	-3.160061	17.85099	-0.18	0.860	-38.73703	32.41691
14	-7.205088	18.00446	-0.40	0.690	-43.08793	28.67775
15	-11.65074	18.00325	-0.65	0.520	-47.53116	24.22968
16	-13.56038	18.00236	-0.75	0.454	-49.43904	22.31828
17	-8.494432	17.98968	-0.47	0.638	-44.34782	27.35896
18	-10.46069	17.96735	-0.58	0.562	-46.26956	25.34818
19	-15.66538	18.41153	-0.85	0.398	-52.35951	21.02875
20	-21.07363	18.39844	-1.15	0.256	-57.74167	15.59441
21	-19.02948	18.62775	-1.02	0.310	-56.15453	18.09557
22	-18.76814	18.63497	-1.01	0.317	-55.90759	18.37131
23	-25.08402	19.21222	-1.31	0.196	-63.37393	13.20589
eventhour	0	(omitted)				
_cons	31.93039	12.75806	2.50	0.015	6.503618	57.35716

Table F-11: Small Business DLC Regression Explaining Snapback

(sum of wgt is 2.1074e+05)

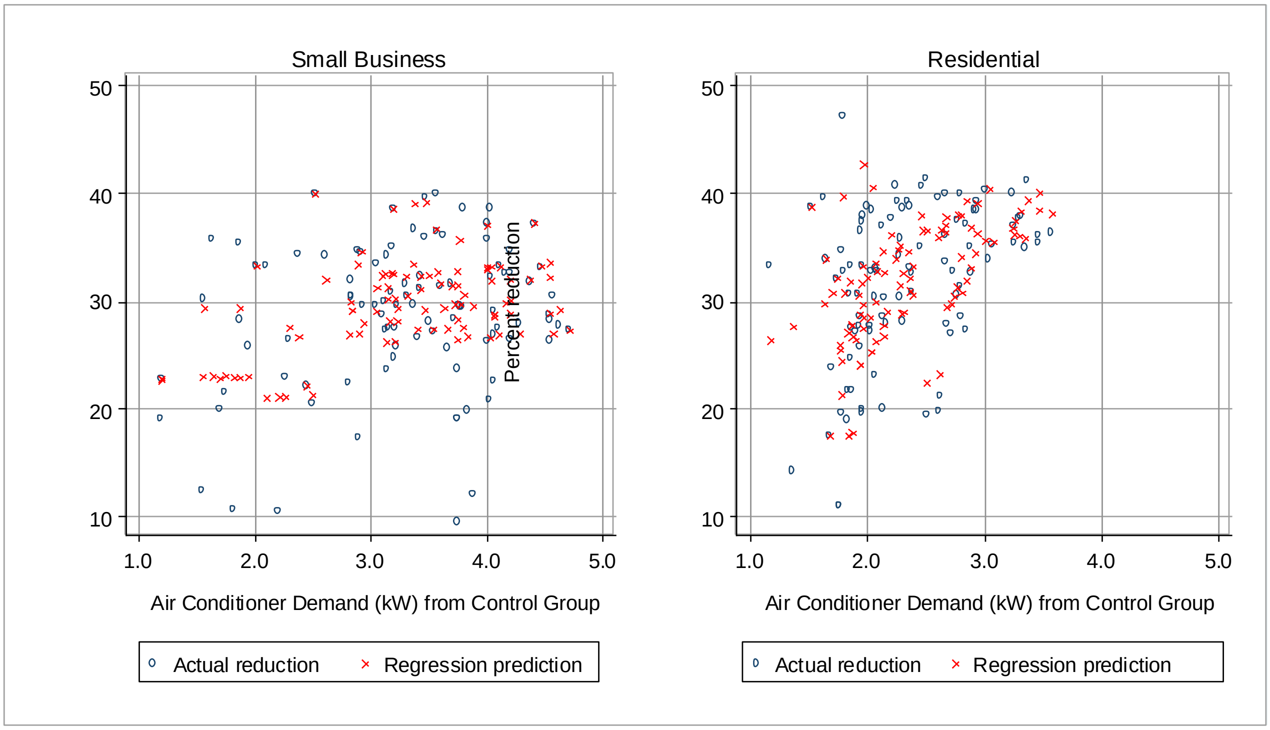
Source	SS	df	MS
Model	806.824465	4	201.706116
Residual	5502.42381	83	66.2942628
Total	6309.24828	87	72.5200952

Number of obs	=	88
F(4, 83)	=	3.04
Prob > F	=	0.0216
R-squared	=	0.1279
Adj R-squared	=	0.0858
Root MSE	=	8.1421

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
posteventhour						
2	2.41616	2.704405	0.89	0.374	-2.962792	7.795113
3	-.7188552	2.724784	-0.26	0.793	-6.13834	4.70063
4	-2.921444	2.724784	-1.07	0.287	-8.340929	2.498041
5	-6.623648	2.742744	-2.41	0.018	-12.07886	-1.16844
_cons	-3.811915	1.900674	-2.01	0.048	-7.592279	-.0315519

Figure F-5 compares the regression predictions against the percent reductions. The blue circles represent actual percent load reductions from past residential DLC events. The red Xs show the model's predictions for load reductions for the same events. As air conditioner demand grows, the residential percent reductions become larger as well. As a result, residential DLC delivers larger demand reductions when peak demands are highest. This relationship is less pronounced for small businesses. The figure also illustrates that the model predicts percent impacts that follow a similar pattern as actual impacts.

Figure F-5: Relationship Between Percent Reductions and Air Conditioner Demand



The regression model allowed us to predict percent reduction and snapback for DLC activation scenarios with different start time and event lengths. This step was necessary to assess when reductions coincide most with the risk of peaking conditions. The percentage reductions were based on the regression model but the estimated air conditioner demand was based on control group loads during the two days that met peaking conditions, as discussed earlier. The reductions, in kW, were calculated by multiplying the air conditioner demand by the percent reductions or snapback for each hour.

The final step was to determine optimal start times for events of different durations at different network groups. This factored in how well reductions coincided with peaking risk for each network group, as illustrated in Section 4.3. For instance, an optimal start time for a five-hour DLC event on a Tier 2 Day Peaking network is 1 PM. For the same type event in a Tier 2 Evening Peak network, the event should begin at 5 PM.

Tables G-12 and G-13 summarize the standardized reductions per hour used for the cost-effectiveness analysis by network group. These estimates are based on an eight-hour event duration because the

DLC program is unconstrained – it can be dispatched when and where needed, as long as it is needed. A positive value indicates a demand reduction and a negative indicates a load increase.

There are several noteworthy observations. The event load reductions vary by network group. The process implicitly assumes that performance in the future will be similar to past performance. A second observation is for most networks, customers do not reduce their load after events. In fact, there is a small amount of snapback following events for each network type. This snapback occurs because the thermostat set point drops back to the regular levels and the air conditioner has to work harder to cool the home. If the load shifting coincides with the peak loads on the network, these load increases can produce negative value. The load shifting behavior and its coincidence with peaking conditions is accounted for in the cost-effectiveness analysis. Event start times do not vary much by network type for the commercial component of DLC. All of the events start between 10 AM and 1 PM.

Table F-12: Standardized Reductions per Device (kW) by Network Group For Business DLC

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.97	0.97	0.00	0.00	0.00	0.00
12	0.00	0.00	0.86	0.86	0.00	0.00	0.00	0.00
13	1.07	0.00	0.91	0.91	1.07	1.07	1.07	1.07
14	0.96	0.97	0.80	0.80	0.96	0.96	0.96	0.96
15	0.84	0.85	0.68	0.68	0.84	0.84	0.84	0.84
16	0.79	0.80	0.63	0.63	0.79	0.79	0.79	0.79
17	0.93	0.94	0.77	0.77	0.93	0.93	0.93	0.93
18	0.80	0.80	0.65	0.65	0.80	0.80	0.80	0.80
19	0.58	0.58	-0.09	-0.09	0.58	0.58	0.58	0.58
20	0.36	0.37	-0.03	-0.03	0.36	0.36	0.36	0.36
21	-0.07	0.34	-0.08	-0.08	-0.07	-0.07	-0.07	-0.07
22	-0.02	-0.06	-0.10	-0.10	-0.02	-0.02	-0.02	-0.02
23	-0.06	-0.02	-0.13	-0.13	-0.06	-0.06	-0.06	-0.06
24	-0.08	-0.05	0.00	0.00	-0.08	-0.08	-0.08	-0.08

Table F-13: Standardized Reductions per Device (kW) by Network Group For Residential DLC

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.46	0.46	0.00	0.00	0.00	0.00
12	0.63	0.00	0.63	0.63	0.63	0.63	0.00	0.63
13	0.76	0.00	0.76	0.76	0.76	0.76	0.00	0.76
14	0.93	0.00	0.93	0.93	0.93	0.93	0.00	0.93
15	0.98	0.00	0.98	0.98	0.98	0.98	0.00	0.98
16	1.05	1.49	1.05	1.05	1.05	1.05	1.49	1.05
17	1.14	1.59	1.14	1.14	1.14	1.14	1.59	1.14
18	1.02	1.46	1.02	1.02	1.02	1.02	1.46	1.02
19	0.82	1.25	-0.21	-0.21	0.82	0.82	1.25	0.82
20	-0.20	1.21	-0.06	-0.06	-0.20	-0.20	1.21	-0.20
21	-0.06	1.17	-0.01	-0.01	-0.06	-0.06	1.17	-0.06
22	-0.01	0.93	0.00	0.00	-0.01	-0.01	0.93	-0.01
23	0.00	0.72	0.01	0.01	0.00	0.00	0.72	0.00
24	0.01	-0.16	0.00	0.00	0.01	0.01	-0.16	0.01

F.4 CoolNYC Impact Analysis

Events from 2012 and 2013 were used to estimate future program demand reductions for CoolNYC. There were four events in 2012 and there had been five events in 2013 at the time of this analysis. For each of these events, all of the installed devices were dispatched. Specific networks were not targeted for any of the events in 2012 and 2013. This lead to a dataset of event demand reductions that spanned several networks as well as a variety of weather conditions. However, there is less variation in event times and durations; each of the curtailment events that occurred in this time period lasted between 5–10 PM or between 6-10 PM. Table F-9 shows the hourly reductions by event for CoolNYC. It reflects the lack of variation in event start times and durations.

Table F-14: 2012 and 2013 CoolNYC Event Summary

Date	Devices Activated	Event Start	Event duration (hours)	Baseline (kW)	Estimated Reductions (kW)	Percent reductions (%)
21-Jun-12	966	17:00	5	0.53	0.12	22%
6-Jul-12	966	18:00	4	0.34	0.05	16%
7-Jul-12	966	18:00	4	0.36	0.06	18%
17-Aug-12	966	17:00	5	0.31	0.11	34%
15-Jul-13	1,640	17:00	5	0.40	0.09	21%
16-Jul-13	1,639	17:00	5	0.41	0.10	24%
17-Jul-13	1,632	17:00	5	0.41	0.09	23%
18-Jul-13	1,665	17:00	5	0.45	0.10	22%
19-Jul-13	1,743	17:00	5	0.43	0.07	15%

Figure F-6 shows the hourly reference loads, or CBLs, by event. This figure illustrates that demand per room air conditioner is quite small, even on hot summer days, in comparison to central air conditioner units. The peak load per room air conditioner, 0.6 kW, limits the potential for demand reductions. Because of this, while 22% of room air conditioner demand is curtailed for plugged devices (on average), reductions per device are relatively small. Figure F-7 reflects the hourly demand reductions provided by CoolNYC events. This figure illustrates the limited variation in demand reductions, which limits the ability to determine degree to which performance varies based on duration, start time and other factors.

Figure F-6: CoolNYC Room Air Conditioner Demand During Events (Control Group)

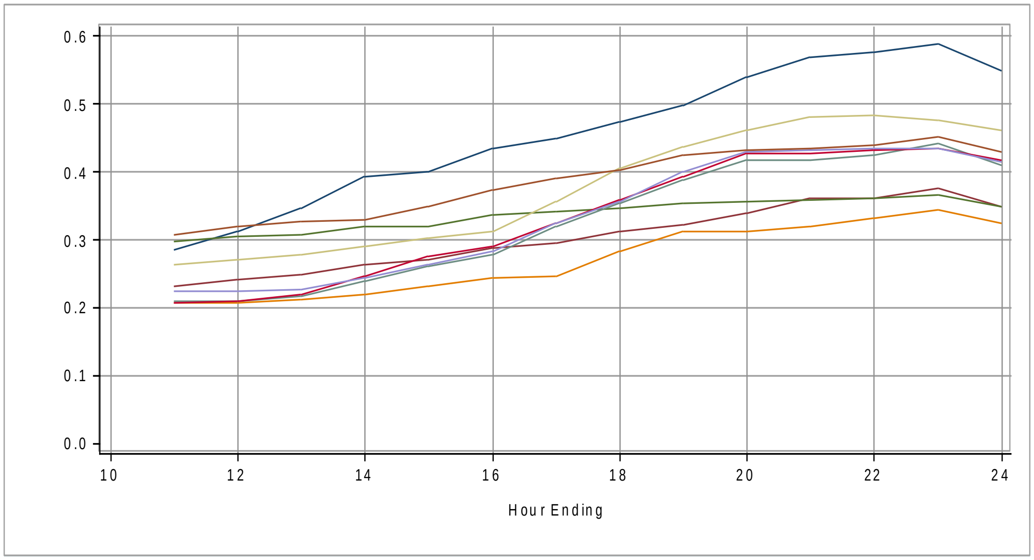
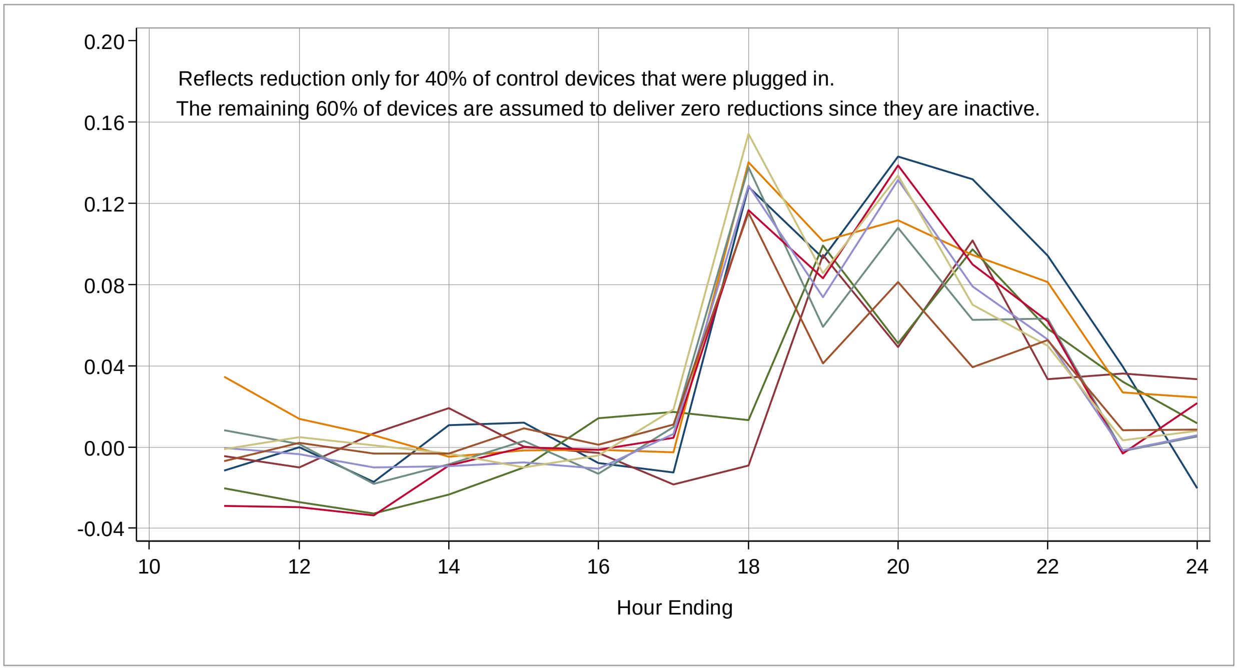


Figure F-7: CoolNYC Demand Reduction per Active Device During Events



The cost-effectiveness model incudes both a flexible option dispatch option – with different start times and durations – and a fixed option that reflects the practice of dispatching CoolNYC from 5-10 PM. Standardizing demand reductions for CoolNYC involved process similar to the one used for DLC. Hourly demands per room air conditioner from all of the events listed in Table F-4 were used to develop an estimate of room air conditioner demand. Next, a regression model was developed using data from the events in 2012 and 2013 in order to explain the relationship between percent load reduction and hour of day, event hour and room air conditioner demand. A similar model was developed to explain snapback. The regression models and corresponding coefficients are summarized in Tables G-15 and G-16.

A series of scenarios with different start times and duration were developed and the percent reductions were estimated by using the regression. The percentage reductions for event hour 1, event hour 2 and so forth were subsequently applied to the standardized room air conditioner demand, producing estimates of the demand reductions. The optimum event start time was found for each event duration and network category and these impacts were then incorporated into the cost-effectiveness model. The event impacts were also estimated for the fixed five-hour events.

Table F-15: CoolNYC Regression Explaining Percent Reductions Per Active Device

Source	SS	df	MS
Model	2845.69826	9	316.188695
Residual	868.832443	33	26.3282559
Total	3714.5307	42	88.4412071

Number of obs =	43
F(9, 33) =	12.01
Prob > F =	0.0000
R-squared =	0.7661
Adj R-squared =	0.7023
Root MSE =	5.1311

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
reference_kw	-48.67787	16.31881	-2.98	0.005	-81.87874	-15.47701
19.event_s~t	-2.525952	2.693562	-0.94	0.355	-8.006045	2.95414
hour						
19	-6.071609	4.34456	-1.40	0.172	-14.91068	2.767465
20	-10.41421	5.170675	-2.01	0.052	-20.93403	.1056105
21	-11.74383	4.815356	-2.44	0.020	-21.54074	-1.946913
22	-17.90745	2.880064	-6.22	0.000	-23.76698	-12.04791
eventhour						
2	-9.398533	4.084755	-2.30	0.028	-17.70903	-1.088037
3	5.663796	4.71409	1.20	0.238	-3.927092	15.25468
4	-3.055628	4.082759	-0.75	0.460	-11.36206	5.250807
5	0	(omitted)				
_cons	53.74344	6.429987	8.36	0.000	40.66153	66.82534

Table F-16: CoolNYC Regression Explaining Post Event Percent Change Per Active Device

Source	SS	df	MS
Model	.079849475	1	.079849475
Residual	227.209957	16	14.2006223
Total	227.289806	17	13.3699886

Number of obs =	18
F(1, 16) =	0.01
Prob > F =	0.9412
R-squared =	0.0004
Adj R-squared =	-0.0621
Root MSE =	3.7684

pctimpact	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
2.postevent~r	.1332078	1.776427	0.07	0.941	-3.63265	3.899065
_cons	2.763289	1.256124	2.20	0.043	.100426	5.426153

Tables G-17 and G-18 summarize the standardized reductions per hour used for the cost-effectiveness analysis by network group. A positive value indicates a demand reduction and a negative indicates a load increase. There are several noteworthy observations. The event performance does not by network group for the fixed option. This is because the data details event reductions for the entire group of CoolNYC participants and is not separated by network. Second, there is not much variation of impacts throughout the event. Lastly, for the flexible option, event start times vary by network group.

This is because the demand reductions are more valuable at different times for each network classification.

Table F-17: Standardized Performance Factors by Network Group (Fixed Five-hour Event)

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
19	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
20	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
21	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
22	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
23	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
24	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01

Table F-18: Standardized Performance Factors by Network Group (Eight-hour Event)

Hour Ending	Tier 2 - Day peak	Tier 2 - Evening peak	Tier 1 – Day peak - low excess	Tier 1 – Day peak - high excess	Tier 1 – Other - low excess	Tier 1 – Other - high excess	Radial - low excess	Radial - high excess
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	0.08	0.00	0.08	0.08	0.08	0.08	0.00	0.00
12	0.08	0.00	0.08	0.08	0.08	0.08	0.00	0.08
13	0.09	0.00	0.09	0.09	0.09	0.09	0.09	0.09
14	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
15	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
16	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
17	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
18	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
19	0.01	0.08	0.01	0.01	0.01	0.01	0.08	0.08
20	0.01	0.11	0.01	0.01	0.01	0.01	0.11	0.01
21	0.01	0.08	0.01	0.01	0.01	0.01	0.01	0.01
22	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
23	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
24	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.01

Appendix G Wholesale Market Energy Prices

Table G-1: Non-Event Day Wholesale Energy Prices Used for Cost-Effectiveness Analysis (Based on 2010-2012 NYC Day-Ahead Market Prices for Average Weekdays)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	$35.65	$28.73	$23.11	$22.25	$23.26	$26.81	$33.47	$28.82	$25.04	$23.18	$28.89	$30.79
2	$33.81	$27.32	$21.83	$20.92	$21.74	$24.42	$30.28	$25.66	$22.60	$21.62	$27.31	$29.46
3	$33.32	$27.17	$21.61	$20.12	$21.22	$23.06	$28.58	$24.55	$21.69	$20.75	$27.01	$29.00
4	$33.85	$27.34	$21.89	$21.02	$21.78	$23.25	$28.17	$24.32	$21.60	$21.36	$27.46	$29.10
5	$36.72	$30.57	$24.40	$24.19	$24.26	$24.75	$29.10	$26.27	$25.09	$25.42	$31.17	$32.26
6	$49.70	$41.06	$34.50	$31.04	$28.56	$29.09	$31.58	$28.99	$30.33	$32.80	$37.96	$39.58
7	$57.91	$44.66	$38.46	$35.32	$32.96	$34.41	$38.60	$34.05	$32.65	$35.81	$41.08	$45.26
8	$56.27	$44.77	$38.59	$38.12	$36.19	$38.14	$43.19	$37.93	$35.05	$36.33	$40.83	$44.39
9	$58.59	$46.18	$39.00	$39.85	$38.97	$42.65	$47.95	$41.19	$37.57	$37.93	$41.46	$45.70
10	$59.32	$46.42	$39.35	$40.93	$41.57	$46.68	$53.89	$44.79	$40.18	$38.91	$41.84	$46.91
11	$57.79	$45.41	$38.60	$41.49	$43.21	$51.72	$60.58	$49.04	$42.53	$39.40	$41.01	$46.02
12	$55.00	$43.28	$37.19	$40.83	$44.10	$56.59	$68.51	$53.16	$44.45	$39.31	$40.11	$44.41
13	$52.47	$41.51	$36.22	$41.06	$45.51	$61.98	$78.72	$59.46	$46.47	$39.25	$39.26	$42.98
14	$50.22	$40.08	$35.68	$40.56	$45.87	$68.08	$86.50	$64.88	$48.12	$38.94	$38.78	$41.56
15	$51.37	$40.33	$35.50	$40.33	$47.17	$73.15	$93.48	$69.20	$50.18	$38.71	$38.71	$42.65
16	$59.20	$44.47	$36.53	$40.02	$46.49	$73.02	$96.14	$70.49	$51.82	$39.24	$43.92	$53.12
17	$77.56	$56.49	$39.40	$39.50	$43.89	$65.65	$84.30	$61.67	$47.19	$39.68	$56.45	$65.38
18	$71.46	$58.45	$42.87	$37.10	$39.66	$53.89	$67.63	$52.13	$42.62	$44.73	$50.43	$58.71
19	$65.36	$50.03	$44.56	$40.79	$38.92	$48.71	$59.39	$48.29	$45.73	$44.92	$46.02	$54.95
20	$59.94	$46.01	$39.29	$42.70	$42.45	$47.65	$57.35	$48.37	$41.66	$38.70	$42.20	$50.11
21	$52.51	$40.27	$33.59	$35.36	$36.97	$44.46	$53.35	$45.01	$37.32	$34.96	$38.06	$43.78
22	$45.27	$35.88	$29.84	$30.24	$30.99	$38.37	$48.08	$40.98	$33.57	$30.52	$34.26	$40.06
23	$40.95	$33.51	$26.99	$26.84	$27.72	$32.73	$44.15	$36.91	$29.65	$27.10	$31.90	$36.42
24	$38.29	$31.52	$25.08	$24.32	$25.79	$30.88	$39.50	$33.25	$28.08	$25.38	$31.27	$34.35

Table G-2: Event Day Wholesale Energy Prices Used for Cost-Effectiveness Analysis (Based on 2010-2012 NYC Day-Ahead Market Prices for Monthly Peaks)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	$62.49	$30.88	$26.41	$21.93	$28.03	$41.21	$47.89	$37.03	$33.55	$24.35	$27.41	$30.24
2	$59.34	$30.14	$24.23	$19.91	$27.00	$39.59	$44.30	$31.69	$28.57	$23.04	$27.09	$28.98
3	$58.13	$31.67	$23.99	$19.21	$26.70	$35.91	$39.57	$31.46	$27.40	$20.89	$26.43	$28.30
4	$60.78	$31.86	$24.20	$19.70	$26.77	$34.00	$37.49	$29.40	$27.21	$21.43	$27.05	$28.44
5	$66.82	$35.60	$27.99	$22.68	$27.79	$35.52	$37.84	$30.83	29.25121	$26.05	$30.68	$31.88
6	$93.18	$47.74	$39.42	$29.74	$30.95	$40.60	$41.14	$33.85	$32.69	$32.44	$39.06	$39.16
7	$106.05	$53.72	$43.70	$34.73	$39.61	$48.81	$54.37	$41.82	$35.28	$34.92	$45.39	$45.95
8	$103.51	$53.06	$44.00	$36.62	$44.30	$56.71	$60.50	$43.50	$38.31	$36.75	$46.73	$45.02
9	$107.69	$53.04	$44.07	$39.57	$47.54	$69.46	$67.78	$47.29	$41.79	$39.05	$46.29	$45.01
10	$107.87	$52.59	$44.77	$41.24	$56.04	$86.15	$89.30	$54.29	$45.49	$43.15	$46.37	$48.89
11	$103.81	$51.16	$44.29	$44.23	$61.53	$127.42	$110.04	$64.33	$51.62	$47.72	$45.19	$47.16
12	$99.08	$49.63	$42.16	$46.03	$70.79	$153.07	$142.58	$73.94	$57.10	$45.51	$43.74	$45.77
13	$97.05	$47.83	$41.13	$51.28	$75.87	$189.33	$170.84	$90.85	$64.21	$47.74	$43.01	$44.10
14	$90.60	$46.76	$40.76	$53.13	$79.42	$223.25	$201.82	$105.42	$71.54	$47.30	$42.99	$42.30
15	$96.02	$46.38	$41.22	$51.34	$85.72	$244.61	$224.00	$113.41	$76.29	$48.84	$42.92	$44.42
16	$108.74	$49.09	$44.39	$50.06	$87.23	$248.89	$217.36	$112.81	$77.28	$48.97	$54.42	$57.27
17	$148.34	$67.59	$48.46	$47.22	$76.94	$228.91	$184.63	$97.78	$66.89	$47.01	$69.10	$68.21
18	$136.83	$65.90	$54.29	$41.45	$62.94	$165.08	$128.56	$74.39	$53.05	$48.81	$58.46	$62.42
19	$122.99	$56.82	$47.91	$43.42	$56.17	$125.69	$99.92	$60.75	$54.69	$51.31	$54.09	$59.83
20	$112.60	$54.31	$46.71	$45.55	$57.68	$115.66	$89.22	$59.02	$52.87	$39.56	$47.78	$54.01
21	$98.19	$46.64	$40.35	$37.34	$46.92	$97.87	$76.93	$53.92	$44.76	$35.63	$42.14	$46.97
22	$84.81	$39.93	$32.55	$33.57	$42.20	$75.68	$68.43	$49.45	$40.24	$31.69	$36.58	$42.43
23	$76.90	$36.38	$30.20	$30.59	$35.32	$54.23	$61.53	$46.21	$37.64	$28.38	$32.65	$34.80
24	$66.06	$35.34	$29.51	$26.16	$31.43	$47.07	$53.77	$40.72	$34.19	$26.78	$32.50	$32.79

Appendix H Model Input Definitions

Input Category	Input	Description
General Levers	Type of Impacts	Assumed weather conditions for analysis period
	Overall Analysis Start (year)	First year of analysis period
	Overall Analysis Period (in years)	Length of analysis period in years
	Discount Rate (Nominal - Utility)	Interest rate used to calculate present values of costs and benefits
	General Inflation Rate	Rise in general level of prices of goods and services used to calculate present values of costs and benefits
	Labor Cost Escalation	Expected % change in labor cost levels
	Analysis Level	Indicates whether results are program specific or portfolio adjusted
	Yearly Capacity Prices Are Inflation Adjusted	(Yes/No). It indicates if generation, transmission, and distribution capacity values need to be scaled for inflation in the calculations.
	T&D Charges (₵/kWh)	The portion of the customer charges per kWh that are associated with transmission and distribution (versus energy production). Used to calculate utility revenue losses and its effect on the rates
Enrollment	Segment Start Year	Year in which program growth is targeted to start for network group
	Segment Growth Period	Planned number of years of growth of the program for network group
	Segment Maintenance Period	Years of maintaining peak enrollment for network group- this means new customers to replace attrition over this period.
	Units at Analysis Start	Enrollment at the beginning of the analysis period for network group
	Units in Peak Year	Peak enrollment during analysis period for network group
	Attrition Rate (due to account turnover)	% of enrollment that leaves the program annually
	Percent Enrolled in NYISO programs	% of enrollment that is also enrolled in NYISO programs
	NYISO/CECONY event day coincidence factor	% Generation benefits CECONY can claim due to load reductions
Fixed cost	Number of Years	Length of analysis period
	Administrative (CECONY)	Annual costs to CECONY of running the program not tied to enrollments
	Administrative (Vendor)	Annual costs to Vendors of running the program not tied to enrollments
	Equipment	Annual costs of equipment not tied to enrollment
	Marketing	Annual marketing costs not tied to enrollment

Input Category	Input	Description
	Measurement and Verification	Annual costs of measurement and verification for the program
	Other fixed costs	Other annual costs not tied to enrollment
Variable Costs	Equipment expected useful life	Expected useful life of program specific equipment
	Average # of devices	Average number of devices per participant
	Marketing acquisition cost (w/o incentives)	Cost to aquire new participants
	Participant sign-up incentives (acquisition)	One time incentives paid to new participants
	Equipment and Installation Cost - Participant	Cost to participant of installing equipment
	Equipment and Installation Cost - Utility	Cost to utility of installing equipment
	Equipment and Installation Cost - 3rd party (e.g. aggregator)	Cost to a 3rd party of installing equipment
	Other one time costs	Other one time costs tied to enrollment
	Annual fixed incentive (e.g., DLC retention)	Annual incentives paid to participants
	Annual option payment (e.g., aggregator capacity payment)	Incentive paid to participants for promising to reduce load on event days
	Annual performance payments ($/MWh)	Incentive paid to participants for reducing load on event days
	Recurring engagement costs (e.g., reminders, notifications)	Cost of reminders and notifications
	Equipment monitoring and maintenance costs	Cost of monitoring and maintaining equipment
	Equipment monitoring and maintenance rate	% of units needing maintenance annually
	Other annual variable costs	Other annual costs tied to enrollment for existing customers
	Participant opportunity costs	Participant costs are listed as a percentage of incentive payments to customers. Many of the costs associated with enrolling and delivering DR that are borne by aggregators and customers are unobservable or difficult to quantify. However, incentive payments are assumed to exceed those costs and allow for a profit margin and, as a result represent an upper bound for participant costs. The default setting for participant costs is 75%.
Generation Benefits	Reserve Margin Requirement	This is the reserve margin requirement as defined by the NYISO. It is the percentage by which installed capacity must exceed the 1-in-2 peak demand.
	2013 Avoided Cost	These are capital costs associated with procuring enough generation capacity to meet extreme demands that expected to occur infrequently. The North American Energy Reliability Council (NERC) guidance recommends sufficient generation capacity to protect against extreme demand levels (1-in-10 peak conditions) although it is not needed for normal day-to-day operations. In some cases, the capacity in
	2014 Avoided Cost	
	2015 Avoided Cost	

Input Category	Input	Description
	2016 Avoided Cost	place to meet extreme peaks can go unused for several years. Rather than spending capital to build additional capacity, some costs can be avoided by instead reducing demand under extreme conditions. We recommend basing values on the NYISO ICAP market and demand curve.
	2017 Avoided Cost	
	Generation capacity escalation rate	Expected annual % change in generator capital costs
Transmission Benefits	Transmission capacity value	Avoided transmission capacity costs per system kW
	Transmission capacity escalation rate	Expected annual % change in transmission costs
	Transmission Line Losses (Peak period)	Probability of transmission line losses during the peak period
Distribution Benefits	2013 Avoided Cost	It is recommended that inputs values be based on an avoided cost study. The model allows for year-by-year inputs, by network type, for up to ten years. Distribution investments are typically driven by load growth, desired improvements in reliability, replacement of aging equipment. While some components of the distribution system are driven by individual peak demands, a substantial share of distribution system expansion is driven by local, coincident demands that are shared across many customers. If a customer helps reduce coincident demand, the unused capacity can accommodate another customer's load growth and avoid or defer investments required to meet that load growth. The avoided distribution costs included should only be those associated with load growth and shared across many customers. The magnitude of avoided distribution investment costs varies based on the characteristics of the load area, including the design of the distribution system, location, trends in customer load growth, load patterns, expected timing of capital investments, the amount of excess distribution capacity, equipment characteristics (e.g., failure rates) and uncertainty in growth forecasts.
	2014 Avoided Cost	
	2015 Avoided Cost	
	2016 Avoided Cost	
	2017 Avoided Cost	
	2018 Avoided Cost	
	2019 Avoided Cost	
	2020 Avoided Cost	
	2021 Avoided Cost	
	2022 Avoided Cost	
	Distribution Capacity Escalation Rate	Expected annual % change in distribution costs. This is inflation rate is applied to any years beyond the ten years input by users.
	Distribution Line Losses (Peak period)	Distribution line losses. This input is used to account for if power had to be delivered were it not reduced, some line losses would be experienced. This value is input as percentage.
Other Benefits	Program provides non-event energy savings	A drop down menu with Yes and No options. Only select yes if the DR program leads to verified non-event day energy savings. Examples of such programs include time-of-use rates and load control devices that allow participants to remotely program and operate air conditioners. The verified non-event days savings must be included in the Impact Library worksheet for the model to estimate benefits.
	Ancillary Service Product	Five different ancillary service market participation options can be select – None, 10 minute synchronized reserves, 10 minute non-synchronized reserves, 30 minute non-synchronized reserves, and regulation services. The default setting is "None" since current NYISO rules do not allow for the participation of disaggregate resources. These options have different requirement for speed of response.
	Ancillary Services Bid price	The bid price submitted into the market. The drop down menu automatically updates based on the product selected. A total of 50 price bid options based on 1^{st} and 99^{th} percentiles in 2010-2012 is automatically populated. To be selected and receive payment, the resource must clear the market. That is, the bid price must be lower than the market price. The selection determines the number of on-call

Input Category	Input	Description
		hours and revenue per MW. The higher bid prices limit availability to mid-afternoon summer hours
	% of Resources Bid into Ancillary Service Market	The share of maximum reduction capability bid into the market. AS products do not have a locational requirement within CECONY territory. Since it is unlikely for reductions to be needed in all networks at the same time, a portion of resources can be bid into the market.
	Environmental Benefits	Environmental benefits due to load reductions, including CO2, NOX, SOX and other pollutants that are monetized and can be avoided by reducing energy consumption. This value is entered in $/MWh.
	Environmental Benefits Escalation Rate	Expected annual % change in price levels
	Other Benefits 1 ($/kW-year)	Other benefits due to load reductions that are based on peak demand reductions
	Escalation rate	Expected annual % change in price levels
	Other Benefits 2 ($/kWh)	Other benefits due to load reductions that are tied to decrease in energy consumption (kWh)
	Escalation rate	Expected annual % change in price levels
	Other Benefits 3 ($/enrollment unit)	Other benefits due to load reductions that on per enrollment unit basis
	Escalation rate	Expected annual % change in price levels
	Other benefits 4 ($/Year)	Other benefits due to load reductions that recur annually on a fixed $ basis
	Escalation rate	Expected annual % change in price levels
Operations	January	Number of events expected to occur in January
	February	Number of events expected to occur in February
	March	Number of events expected to occur in March
	April	Number of events expected to occur in April
	May	Number of events expected to occur in May
	June	Number of events expected to occur in June
	July	Number of events expected to occur in July
	August	Number of events expected to occur in August
	September	Number of events expected to occur in September
	October	Number of events expected to occur in October
	November	Number of events expected to occur in November
	December	Number of events expected to occur in December

Appendix I Input Sources

<table>
<tr><th rowspan="2"></th><th rowspan="2">Input</th><th colspan="5">Source</th></tr>
<tr><th>DLRP</th><th>CSRP</th><th>Small Business DLC</th><th>Residential DLC</th><th>CoolNYC</th></tr>
<tr><th rowspan="8">General Levers</th><td>Overall Analysis Start (year)</td><td colspan="5">Assumed to be 2013 in order to provide values in current dollars</td></tr>
<tr><td>Overall Analysis Period (in years)</td><td colspan="2">Assumed to a single year</td><td colspan="3">Based on useful device life assumption. Value varies between existing and new customers.</td></tr>
<tr><td>Discount Rate (Nominal - Utility)</td><td colspan="5">Provided by CECONY and consistent with other filings – 7.72%</td></tr>
<tr><td>General Inflation Rate</td><td colspan="5">Provided by CECONY and consistent with other filings – 2.1%</td></tr>
<tr><td>Labor Cost Escalation</td><td colspan="5">Assumed to be same as the general inflation rate – 2.1%</td></tr>
<tr><td>Yearly Capacity Prices Are Inflation Adjusted</td><td colspan="5">Yes. Generation, transmission and generation capacity values input into the model are all in nominal dollars and are thus inflation adjusted.</td></tr>
<tr><td>T&D Charges (₵/kWh)</td><td colspan="5">Delivery charges are based on CECONY's electric tariff book, which includes delivery charges, is available at: http://www.coned.com/documents/elecPSC10/SCs.pdf. Service classifications 1, 2 and 9 were used for residential, small business, and large customer programs, respectively. The charges used were, respectively, 8.9₵, 10.2₵, and 5.4₵. Large customer delivery charges include both volumetric, 2.4₵/kWh, and demand component. The demand charges vary depending on the size of the customer and whether or not they receive power through high or low tension lines. For 300 kW customers, those charges are $24 per kW for low tension service and $20 per kW for high tension service. For simplicity, demand charges where assumed to be $22 per kW and converted into an effective kWh rate by dividing the value by the number of hours when the peak demand could occur over the course of a month.</td></tr>
<tr style="display:none"><td></td></tr>
<tr><th rowspan="7">Enrollment</th><td>Segment Start Year</td><td colspan="5">Assumed to be 2013 in order to provide values in current dollars</td></tr>
<tr><td>Segment Growth Period</td><td colspan="5">Assumed to be zero for existing participants and one year for new participants</td></tr>
<tr><td>Segment Maintenance Period</td><td colspan="5">Assumed to be zero. This effectively limits any replacement participants and associated benefits and costs. It allows for cost-effectiveness of existing customers and new customers can be estimated independently.</td></tr>
<tr><td>Units at Analysis Start</td><td colspan="5">Enrollment as of July 2013, based on files provided by CECONY</td></tr>
<tr><td>Units in Peak Year</td><td colspan="5">For existing customers, the value is assumed to be the same as the units at analysis start (since only one year is used).</td></tr>
<tr><td>Attrition Rate (due to account turnover)</td><td colspan="2">Based on analysis of CECONY's enrollment files. See Section 5.1 and Table 5-2 for more detail.</td><td colspan="2">2012 Evaluation</td><td>Assumed to be 10%</td></tr>
<tr><td>Percent Enrolled in NYISO programs</td><td colspan="4">2013 Enrollment data</td><td>Assumption</td></tr>
</table>

	NYISO/CECONY event day coincidence factor	Calculated by FSC using 2011-2013 historical event data and NYISO system load data (available at www.nyiso.com)			
Fixed cost	Number of Years	Assumption	DLC 2012 TRC	DLC 2012 TRC	Assumption
	Administrative (CECONY)	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
	Administrative (Vendor)	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
	Equipment	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
	Marketing	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
	Measurement and Verification	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
	Other fixed costs	2012 Evaluation	DLC 2012 TRC	DLC 2012 TRC	2012 Evaluation
Variable Costs	Equipment expected useful life	Not applicable	Provided by program managers		
	Average # of devices	Not applicable	Not applicable since analysis was done on a per device basis (versus household)		
	Marketing acquisition cost (w/o incentives)	2012 Evaluation plus guidance from program managers in interpreting costs	2012 TRC models plus guidance from program managers in interpreting costs		2012 Evaluation plus guidance from program manager
	Participant sign-up incentives (acquisition)	2012 Evaluation plus guidance from program managers			
	Equipment and Installation Cost - Participant	2012 Evaluation plus guidance from program managers in interpreting costs	2012 TRC models plus guidance from program managers in interpreting costs		2012 Evaluation plus guidance from program manager
	Equipment and Installation Cost - Utility	2012 Evaluation plus guidance from program managers in interpreting costs	2012 TRC models plus guidance from program managers in interpreting costs		2012 Evaluation plus guidance from program manager
	Equipment and Installation Cost - 3rd party (e.g. aggregator)	Not observable. Assumed to be reflected in participant opportunity costs.			
	Other one time costs	2012 Evaluation plus guidance from program managers in interpreting costs	2012 TRC models plus guidance from program managers in interpreting costs		2012 Evaluation plus guidance from program manager
	Annual fixed incentive (e.g., DLC retention)	Not applicable			Assumption with feedback from program manager

	Annual option payment (e.g., aggregator capacity payment)	2012 Evaluation Report plus verification from program managers		Not Applicable		
	Annual performance payments ($/MWh)	2012 Evaluation Report plus verification from program managers		Not Applicable		
	Recurring engagement costs (e.g., reminders, notifications)	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers
	Equipment monitoring and maintenance costs	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers
	Equipment monitoring and maintenance rate	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers
	Other annual variable costs	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers	2012 Evaluation/Discussions with program managers
	Participant opportunity costs	Assumption based on California 2010 DR Cost Effectiveness Protocols. Available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm				
Generation Benefits	Reserve Margin Requirement	Based on NYISO capacity demand curve documentation. Available at: http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2013/Summer_2013/Documents/Demand_Curve_Summer_2013_Revised.pdf				
	2013 Avoided Cost	2013 values are based on NYISO's 2013 summer auction NYC results, which provides capacity payments for the six months when CECONY's programs are active. Auction results can be found at: icap.nyiso.com/ucap/public/auc_view_monthly_detail.do 2014-2017 costs are assumed to migrate, in linear fashion, toward the cost of new entry, an estimate of the capacity payments needed to encourage new peaking generation. Documentation regarding the cost of new entry and other determinants of NYISO's ICAP demand curve can be found at: http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2013/Summer_2013/Documents/Demand_Curve_Summer_2013_Revised.pdf				
	2014 Avoided Cost					
	2015 Avoided Cost					
	2016 Avoided Cost					
	2017 Avoided Cost					
	Generation capacity escalation rate	Assumed to be same as the general inflation rate				

Transmission Benefits	Transmission capacity value	Included with Distribution benefits
	Transmission capacity escalation rate	
	Transmission Line Losses (Peak period)	Con Edison Transmission & Distribution Losses, Technical Conference presentation on July 17, 2008
Distribution Benefits	2013 Avoided Cost	Consolidated Edison Company of New York, Inc. Marginal Cost of Electric Distribution Service - NERA Report
	2014 Avoided Cost	
	2015 Avoided Cost	
	2016 Avoided Cost	
	2017 Avoided Cost	
	2018 Avoided Cost	
	2019 Avoided Cost	
	2020 Avoided Cost	
	2021 Avoided Cost	
	2022 Avoided Cost	
	Distribution Capacity Escalation Rate	Assumed to be the same as the General Inflation Rate
	Distribution Line Losses (Peak period)	Con Edison Transmission & Distribution Losses, Technical Conference presentation on July 17, 2008
Other Benefits	Program provides non-event energy savings	Defined by user, default set to “Yes”
	Ancillary Service Product	Defined by user, default set to blank
	Ancillary Services Bid price	Based on NYISO ancillary service market data. Available at: http://www.nyiso.com/public/markets_operations/market_data/pricing_data/index.jsp
	% of Resources Bid into Ancillary Service Market	Defined by user, default set to zero
	Environmental	

	Benefits	Not applicable to this analysis, but information may be found at RGGI website: http://www.rggi.org/market
	Environmental Benefits Escalation Rate	
	Other Benefits 1 ($/kW-year)	Defined by user, default set to zero
	Escalation rate	
	Other Benefits 2 ($/kWh)	
	Escalation rate	
	Other Benefits 3 ($/Year)	
	Escalation rate	
	Other benefits 4 ($/Year)	
	Escalation rate	
Operations	January	Based on Frequency of Historical Events
	February	
	March	
	April	
	May	
	June	
	July	
	August	
	September	
	October	
	November	
	December	

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