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Consolidated Edison Company of New York, Inc. Marginal Cost of Electric Distribution Service

Final Report

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I. INTRODUCTION AND OVERVIEW OF APPROACH

Consolidated Edison Company of New York, Inc. (CECONY) retained NERA Economic Consulting (NERA) to advise CECONY on the development of marginal electricity distribution costs. As discussed among NERA, CECONY and the Staff of the New York State Department of Public Service (Staff), the estimates were intended to be used in total resource cost calculations for Energy Efficiency.

This study is a collaborative effort between CECONY and NERA. The approach to be used in the quantification of marginal costs was a planning/engineering based approach, with the marginal costs determined based on distribution planning practices and the cost quantification derived to the maximum extent practicable from either engineering estimates or actual costs of specific projects. NERA worked with CECONY to develop a detailed understanding of the distribution system planning process and to identify engineering analyses that would yield reasonable marginal costs reflective of the drivers of that process.

The method we have developed with CECONY for estimating marginal distribution costs leads naturally to taking a first view of these expenditures on a geographic basis. This is the case because costs themselves vary by geography due to terrain and density issues. CECONY performed those analyses and reviewed the results with NERA. NERA assembled the analyses into marginal costs by area and developed system weighted marginal costs. Note that individual areas were examined when there were sufficient data, however, in some cases areas were combined. All marginal cost estimates are presented in 2011 dollars as well as nominal dollars when they are presented over time.

The study excludes an analysis of transmission investments, since it was assumed that the congestion cost adder included in NYISO's location-based marginal prices (LBMPs) already reflects the short-run marginal transmission costs associated with changes in demand at any given hour and location. However, we note that the congestion adder included in locational market prices does not necessarily reflect the full incremental cost of new transmission assets as transmission may be required for load-relief reasons that are not related to LBMP differences.

At the onset of the study, NERA reviewed the cost of switching station projects that generally provide load relief for area station needs. Energy efficiency measures have an impact on the need for building or upgrading switching stations, and the CECONY study should capture that component of avoided cost. However, upon evaluation of the expected switching station investment in the current planning horizon, it was determined that the benefits of new switching stations may somewhat offset LBMP prices. Such benefits would need to be verified for each individual switching station in order to adequately estimate the net level of avoided costs. For these reasons, switching stations were excluded from the marginal distribution cost study. However, it is possible that the Company may decide to include such investments in future marginal cost analyses depending upon the contribution of switching station investments to distribution load relief and the ability to reasonably identify LBMP impacts.

The method we have worked with CECONY for estimating marginal distribution costs can be summarized as follows:

- Define segments of the distribution system that are distinctly planned and expanded.
- For each segment, identify the demand measure that the system is planned for and clearly identify that demand measure.
- For each segment, identify the unit (i.e., per kilowatt of demand or capacity, or per customer) cost of projects planned or undertaken to serve incremental demand. If analyzing an investment or expenditure using capacity, estimate the amount of capacity in the segment needed to serve additional units of load and adjust the cost accordingly.
- Convert marginal investments to annual marginal costs using carrying charges, O&M and other applicable loading factors, and an allowance for working capital.
- Determine if there is long term excess capacity in the system or segment and if that is the case, develop marginal costs on a year by year basis to reflect the impact of excess capacity.
- Restate avoidable distribution marginal costs to unit marginal costs per kW of system peak contribution. This is done as Con Edison’s practice is to measure energy efficiency measures in terms of the impact on coincident system peak. Note that a system coincidence factor was applied to the upstream distribution marginal costs (area stations and subtransmission) and a separate system coincidence factor was

applied to estimates of primary and secondary feeders as explained in Section III.A. These factors are based on aggregated data. More refined estimates would require additional data to take into account timing of peak loads at different segments within a region as well as coincidence across regions.

The primary objective of this study was to explore and implement a methodology for quantifying marginal distribution costs that explicitly reflected the planning and engineering of the system. All initial estimates of marginal investment are made on a geographic basis. These estimates were then weighted by geographic loads to determine system weighted costs, as presented in this report. In performing the study, NERA used standard marginal cost parameters such as O&M loading factors and working capital allowances developed by CECONY for prior studies. These parameters were not updated as they are reasonably current. NERA and CECONY reviewed how NERA assembled the cost analyses provided by CECONY and agreed that the costs presented reflect a reasonable estimate of CECONY's marginal distribution costs for the applications described herein.

While the marginal cost quantification performed was consistent with the original work scope, refinements were made as the project progressed to better reflect the realities of distribution planning and data availability. Additionally, this report addresses only the distribution avoided costs associated with energy efficiency.

II. KEY CONCEPTS

The study is predicated on several key concepts that are described in this section of the report, and will be referred to when discussing the marginal cost quantification of each segment.

A. Demand Measures and the Collective/Individual Distinction

The first key concept is distinguishing between elements of the system that are driven by growth in coincident demand, and elements that are driven by customer's expected maximum individual demand, also referred to as design demand. In the first case, the coincident demand need not be coincident with the system peak demand, but could be the coincident demand of an area or network.

The major implication of this distinction is that segments of the system for which expansion is driven by coincident demand are shared. If a customer reduces the coincident demand placed on that element, the "freed-up" capacity could be used to accommodate another customer's load growth and would avoid or defer the investment required to meet that load growth. As a result, there is positive avoided cost associated with demand reductions in a shared segment or element of the distribution system. This will only be the case if there is not excess capacity on the system segment. If there is excess capacity, while capacity would be freed-up, it would not avoid or defer an investment as other customer load growth could be accommodated by the existing excess capacity. Likewise, if the customer reduces demand in hours other than the time of the segment's peak demand, there are zero avoided costs because the system has excess capacity in those non-peak hours.

In contrast, there are portions of the system that are designed to meet the individual customer's maximum demands. When a customer reduces demand on a design demand segment, the freed-up capacity is not usable by another customer, even if that load reduction takes place at the same time when the area peaks. The freed up capacity would simply be unutilized and would not defer any investment. We will refer to capacity that is planned based on coincident demand as "collective capacity" and capacity planned based on design demand as "individual capacity".

The distinction between collective and individual capacity can be blurry as certain elements of the system, e.g., a secondary line, may serve more than one customer, but not enough customers that a reduction in demand by one customer will free-up capacity likely to be used by another customer. The design-demand segment would have been sized based on the sum of the anticipated long-term maximum demands of the local customers served off that facility. Therefore reductions of demand by one of the customers are unlikely to save any investment in that type of facility.

In the case of CECONY the distinction between collective and individual capacity is clearer than it is for many utilities as the vast majority of the CECONY distribution system is networked at the secondary level, meaning that all segments up to the service are shared or sized based on collective capacity. In this case, changes in customers' usage at the time of the local coincident peak can have an impact on the needed amount of investment in the particular area over time. We discuss with respect to each system segment the determination of whether the segment is considered collective or individual.

B. Excess Capacity, DSM and Load Transfers

As noted above, a load reduction will not trigger an avoided cost if there is excess capacity in a system segment. Distribution systems have a natural tendency to have excess capacity caused by the lumpiness of investment. When facilities need reinforcement it makes sense to reinforce with equipment that will more than solve the capacity need in order to avoid the need for frequent smaller scale investments that tend to have a higher per unit investment cost. If there is excess capacity, marginal cost for practical purposes may be zero as no investments will change in the reasonably near term in response to demand changes.

In understanding the concept of excess capacity, it is important to acknowledge the impact of Demand Side Management (DSM) efforts that are already underway and/or planned for the study period. Expected DSM measures, including the Energy Efficiency Portfolio Standard (EEPS) program, contribute to the periods of excess capacity observed in this study. In particular, the expected load reduction benefits have already been captured by the load projections that this study uses to determine area station marginal costs. The load projections used to determine the area station marginal costs include approximately 450 MWs of DSM reductions (including EEPS program savings). These reductions were forecasted through 2020 and were included in the '2011-2030 Long-Range Substation Load Relief Program'. The majority of these achievements were projected through 2017. In addition, projects that would have otherwise appeared in the "Area Station and Subtransmission Costs" category were deferred. As a result, the stated marginal costs presented in this study are representative of avoided costs for additional efficiency programs not already included in the load forecast.

Identifying the resulting excess capacity after accounting for DSM is especially important when deciding on the level of incremental energy efficiency efforts that are economic in a given year, and it is particularly important when there is sustained excess capacity. If there is excess capacity for a number of years and the time at which such excess will no longer exist can be identified, marginal cost can be quantified on a year by year basis. In this study we employ the concepts of collective and individual segments of the system and the concept of excess capacity. We will describe the methods and assumptions used with respect to these concepts as we review the nature of the CECONY distribution system.

The third key concept concerns load transfers, which are related to excess capacity. As noted above, excess capacity is a natural outgrowth of the economics of installing equipment that will not be replaced with high frequency. It does not make economic sense to expand distribution capacity to just meet load, as over time it is more economical to add equipment that will accommodate multiple years of load growth. CECONY optimizes its system and the use of such capacity through load transfers. These transfers can occur at the network level where portions of one network load may be transferred to another to take advantage of excess in one network, and at the area station level where load served by one area station may be transferred to another. These transfers reduce the likelihood of localized excess capacity as that excess can be used to accommodate a transfer, but do not eliminate potential excess capacity.

C. Load-Carrying Capacity Unit Cost

The fourth key concept concerns developing per-kW costs based on the load carrying capacity of the equipment installed to meet load growth under applicable contingency conditions. For most segments of the network distribution system, this involves second contingency conditions. Costs per unit of load carrying capacity are used for most segments of the collective system, as these costs account for the amount of load growth that investment can support over time. It is possible that in any one year, a small decrement in load is able to defer a large investment and the avoided unit cost would be quite high. However, the avoided investment would have produced excess capacity that would lower marginal costs in subsequent years. Stating marginal/avoided costs per unit of load carrying capacity will smooth out these fluctuations.

The concepts discussed above are rarely black and white in application. However, for purposes of this study we made a determination of how to classify each segment of the system with respect to the above concepts based on the dominant characteristics.

III. OVERVIEW OF THE CECONY SYSTEM AND MARGINAL COST APPROACH FOR EACH SEGMENT

A. Approach for Segment, Voltage Level and System Weighted Average Costs

We estimated per unit marginal costs for most of the system segments by area. These per unit marginal costs were later weighted to an overall system level. A system coincidence factor of .988 that takes into account the relationship between overall system coincident peak and the sum of independent regional peaks was applied to the system-weighted cost of area stations and subtransmission to state all costs in dollars per kW of coincident peak. A separate system coincidence factor of .977 that takes into account the ratio of system coincident peak to the sum of regional network loads was applied to primary and secondary marginal costs.

Before describing the weighting process we will first describe various configurations from which customers are served. All configurations require the use of area stations. Area stations transform power from the 138 kV level to primary distribution voltages. A large portion of these area stations are fed from 345/138 kV switching stations or subtransmission emanating from those stations. As discussed above, these switching stations may have LBMP impacts and are not included in this study.

Further, all configurations require the use of primary voltage facilities. High tension (HT) customers or those taking service at primary voltage share the primary facilities with secondary customers, but do not require any secondary facilities. Primary customers in network areas use primary facilities that are connected to secondary distribution networks and are primarily underground, while primary customers in non-network areas use overhead primary facilities not connected to secondary networks. Hence, we distinguish between network area primary marginal costs and non-network area primary marginal costs.

Customers served at the secondary voltage level are served in three configurations. First, most secondary customers in network areas are served from the secondary network using networked transformers. Second, larger secondary customers in network areas are served from dedicated transformers on spot or isolated networks. Third, secondary customers in non-network areas are served from overhead transformers that are not networked. We need to account for all these loads when weighting results to calculate a marginal cost for each area and configuration.

For all elements that are considered collective and avoidable, we weight regional marginal costs by the regional independent peak loads, which are the sum of independent area substation peaks in a region, in order to compute a system-weighted average. The independent regional peak loads used are those for all customers, i.e., including all network customers, all non-network customers, all high tension (HT) customers and all customers large enough to be served from a spot or isolated network. The sum of regional independent peak loads is greater than system coincident peak as the area stations within a region do not necessarily peak at the same time and the regions do not necessarily peak at the same time. To convert the system weighted marginal cost into a cost per coincident peak, we apply the system coincidence factor as explained above.

We computed weighted costs at the segment level and at the system level. When developing a Segment-Weighted Marginal Cost, we produce values applicable to all loads on that segment. When developing a System-Weighted Marginal Cost, the value applies to all loads on the system. For example, for customers served from a secondary network, we compute a segment-weighted average cost of network transformers applicable to customers served from the secondary network, or Segment-Weighted Marginal Cost using the regional costs and weighting by the load served from the secondary network in each area. This is the cost that could be avoided by an energy efficiency program applicable to just customers served from the secondary network. In computing a System-Weighted Secondary Cable and Transformer Marginal Cost, the costs corresponding to secondary cable and transformers in non-network areas and in spot or isolated networks are assigned a zero weight, as none of these costs are avoidable. The resulting weighted value represents the cost that could be avoided by an energy efficiency program applicable to any customer in the system.

We examined marginal costs for the major components and segments of the CECONY system. We provide an overview of each segment below.

A. Area Station and Subtransmission Costs

CECONY provided information on projects related to area stations and subtransmission projects through 2030. Area stations are fed by 138-kV feeders that emanate from either switching stations or directly from generation. These area stations convert electricity to distribution voltages to be sent over primary feeders. We use this detailed information to develop marginal costs by area and by year.

We divide this investment into two categories. The first are minor projects that do not include construction of a new area station. These projects can involve shifting load between area stations and include upgrading 138-kV subtransmission feeders, replacing limiting elements of the system, adding transformer cooling or adding a new transformer at an existing area station.

However, eventually a new area station, which represents a major investment, is needed. The approach we take is to identify when a new area station is needed in each region. Once an area station is needed, we take a weighted average of the cost per-kW of load carrying capability for all projects including that new station from the need date through 2030. This unit cost is the marginal investment from the new station need date forward. It is phased in to reflect the Company's construction schedules. The weighted area station cost per unit of load carrying capacity is used to represent the cost per kW of peak substation load in the region and in each year.

The annual marginal costs weighted over the service territory for area station and subtransmission investment in both constant 2011 dollars and nominal dollars from 2011 to 2030 are shown in Table 1 below for each year. These costs were initially computed as a cost per unit of regional independent peak load and have been restated to a cost per system kW by applying a system coincidence factor.

Table 1. Area Station and Subtransmission System-Weighted Marginal Cost

Year	System Weighted Marginal Cost	Nominal System Weighted Marginal Cost
	(2011 US$ per kW)	(US$ per kW)
	(1)	(2)
2011	0.43	0.42
2012	5.44	5.61
2013	12.88	13.67
2014	6.29	6.87
2015	38.43	43.26
2016	70.50	81.73
2017	41.02	48.98
2018	102.05	125.51
2019	92.95	117.74
2020	109.47	142.83
2021	92.81	124.72
2022	129.32	179.01
2023	144.47	205.98
2024	129.30	189.88
2025	159.80	241.71
2026	159.87	249.07
2027	159.94	256.66
2028	160.04	264.52
2029	160.11	272.58
2030	160.19	280.89

Note that these marginal costs are avoidable from load reductions as these facilities are planned for the collective demand of all customers and can be shared over all load in the area. The avoided cost associated with a uniform load reduction over the service territory is the system-weighted cost.

B. Primary Feeder Costs

1. Primary Feeder in Network Areas

Primary feeders take power from the area stations directly to high tension customers and also connect to the secondary system. The CECONY distribution system has two types of configurations. The first is an underground network system which serves the vast majority (about 80%) of total load. The second is an overhead loop and radial system serving the less dense areas. We examine primary marginal cost separately for each configuration.

In network areas, the primary facilities are used by three types of load.

- The first is high tension load which is served directly from the primary system using primary voltage services. These customers provide their own transformation to lower voltages.

- The second is secondary load served on isolated or spot networks. These customers use dedicated secondary transformers that serve one specific location (i.e., non-network transformers) and are connected to the network primary facilities.

- The third is secondary load served from the secondary network. These are customer loads which are served from a network of transformers and secondary cables that are connected to network primary configurations. All these loads share the same primary facilities. The need for primary facilities is driven by the network peak load as load can be transferred from one feeder to another.

To quantify the network marginal primary costs, CECONY distribution planners examined a variety of recent primary voltage jobs that upgraded and added primary facilities. These jobs were a mix of organic growth jobs and customer notice jobs. Organic growth jobs are projects done to relieve loading problems that are not associated with a customer notice that load is being added. Customer notice jobs are projects done in connection with new customer additions or load increases that have been notified to the company by the customer. Only jobs involving primary facilities were used to develop the primary marginal cost. For each job, the marginal primary facilities cost was determined per kilowatt of added effective capacity (second contingency, where applicable), as opposed to nameplate capacity. Because the unit costs are developed per kW of added effective capacity[1], they represent the unit cost per kW of network peak demand, as the capacity is measured as the added load that the investment enables the network to serve. A Segment-Weighted Average of Primary Feeder Cost in Network Areas was then calculated using the independent peak network loads in each area as weights. These marginal cost per network peak were then restated in costs per system kW by using the system coincidence factor.

Table 2 below shows the Segment-Weighted Marginal Costs in Network Areas per coincident system kW. Note that the costs are stated in 2011 dollars and we do not show cost year by year. This is because the cost in real terms does not change over the years, as there is no chronic excess capacity in this system segment. A separate marginal cost was developed for primary facilities for non-network areas, as described in the next section.

Table 2. Segment-Weighted Network Primary Feeder Costs per System kW

	Marginal Cost (2011 $ per kW)
Segment Weighted	26.82

Several key points need to be considered with respect to primary costs in network areas. First, these are collective costs, as the primary facilities in network areas are shared. Second, these costs are classified as avoidable. Third, these costs are marginal (and avoidable) starting now.

In discussions with CECONY distribution planners, we reached an understanding that the networked primary distribution system does not have significant amounts of excess capacity on a widespread basis and work is performed throughout various networks to expand capacity as load grows. This does not mean that there is no localized excess capacity in the initial years after a project is undertaken in a specific area. However, load can be redistributed among feeders.

[1] Effective capacity is not the rating of the equipment but the amount of added load that the equipment can serve under design conditions. It effectively includes the "reserve margin".

Additionally, one specific location may have excess capacity for several years after a project has been done and an increment of load can therefore have a low or zero marginal cost, while another location may be very close to needing new capacity and a small change in load may trigger a new project that would have a very high cost per added kW of load. It would not be practical for marginal costing purposes to examine every feeder and determine for every year what the response to a load change would be. Instead we used the cost per unit of added effective capacity of a feeder to correct for the immediate excess capacity after investment, and better represent the cost per unit of network peak load. After that we restated this cost per system kW by using the system coincidence factor. We assumed that the result is representative of the network cost per kW of system peak as there is no chronic excess or deficient capacity in this system segment.

We also note that we classified this segment as collective and therefore avoidable. This means that it is not the customer's individual demand that drives the design of these facilities but the changes in network peak and therefore the sum of customers' contributions to the network peak. There are likely exceptions where, for example, a large high tension load is the main load on a particular section of a feeder, but in general the collective assumption fits the picture.

2. Primary Feeder Costs in Non-Network Areas

Primary feeder costs were also examined for non-network areas. These feeders also take power from area stations to either high tension customers or customers served from secondary facilities. Non-network primary facilities consist of a mix of loops and radial feeders. However, the secondary facilities in these areas are not networked. Roughly 20% of the system load is served in non-network areas. CECONY looked at the annual level of expenditures on primary facilities in non-network areas and developed a unit cost per kW of annual load growth on feeders in those areas. For practical purposes this is reasonably equivalent to network load in network areas.

Table 3 below shows the Segment-Weighted Marginal Primary cost for non-network areas. Note that the cost is in 2011 dollars and we do not show cost by year as the cost in real terms does not change over the years due to no chronic excess capacity in this system segment. We show the Segment-Weighted Marginal Cost in cost per system coincident kW, after applying the system coincidence factor.

Table 3. Segment-Weighted Non-Network Primary Feeder Costs per System kW

	Marginal Cost
	(2011 $ per kW)
Segment Weighted	28.33

As with primary facilities in network areas, this segment of the system is considered collective and the costs are avoidable. While given the lower density of these areas and the fact that the configuration of the system includes radial feeders, portions of these facilities may not be fully collective as they would be shared with a smaller group of customers and a reduction in demand may only be available as freed-up capacity to a small customer group. Nonetheless, in discussions with CECONY we agreed that the dominant characteristic of these facilities is that they are collective and therefore treating them as collective would be reasonable.

3. System Weighted Primary Feeder Costs

Table 4 below shows the System-Weighted Marginal Costs of Primary Feeders. It combines the primary costs for network and non-network areas, using share of network and non-network loads as weights. To arrive at this figure, the costs for network and non-network areas for each region were weighted together.

Table 4. System-Weighted Primary Feeder Costs per System kW

	Network Areas	Non-Network Areas
	---------------(2011 $ per kW)----------------	
(1) Segment Weighted Marginal Cost	26.82	28.33
(2) Independent Loads (MW)	10,681.68	2,772.32
(3) System Weighted Marginal Cost	27.14	

C. Transformers and Secondary Cable Costs

1. Transformers in Network Areas

There are two secondary transformer configurations in network areas. The predominant configuration is transformers that are networked. They are connected to primary feeders and to a network of secondary cables. Most secondary customers are then served by services that tap into the secondary cables. The networks are in most locations designed for second contingencies. Unlike a radial secondary system, where a networked transformer is limited to serving the customers directly attached to it or to the individual secondary conductor connected to it, networked transformers are available to serve all load connected to the networked feeders.

The second configuration is for secondary customers on spot or isolated networks. In those cases, dedicated transformers are fed at primary voltage from primary feeders and a single customer or location is served from a group of dedicated transformers. This configuration is used for large secondary customers, typically over 1000 kW. The design criterion is also second contingency. In some cases hybrid situations exist where there may be a limited tie between the network and a transformer on a spot network, but these are not common and were not considered in the marginal cost calculations.

For the first configuration, the networked transformers were determined to be collective. The design criterion assumed network peak load. CECONY distribution planners assembled a sample of recent projects related to organic growth and customer notices. This sample had a variety of cost data including transformer costs which included equipment costs, installation costs and other costs such as vault cost where applicable. Each job had a value for the effective capacity added, that is the amount of load that could be served under second contingency conditions. We computed from this sample the cost of networked transformer capacity per kW of added effective capacity. Both Segment-Weighted and System-Weighted Marginal Costs were developed. The System-Weighted Marginal Cost assigns a zero weight to marginal cost for this segment in non-network areas, to high tension loads and to load served on spot and isolated networks. These costs were then converted into costs per system coincident kW using the system coincident factor and are shown in Table 5 below.

Table 5. Segment and System-Weighted Network Transformer Marginal Costs per System kW

	Marginal Cost (2011 $ per kW)
Segment Weighted	32.16
System Weighted	16.47

As with primary feeders, we discussed with CECONY whether there was excess capacity on these segments and we agreed that there was not. Hence this cost begins to apply in 2011 and is avoidable and applicable to all future years. The cost per kW of effective capacity is representative of the cost per kW of network peak secondary load, as the effective capacity and network peak load are equivalent when there is no excess capacity. While the particular investments examined were targeted for a specific portion of the network that needed reinforcement, they apply to all network load. This is because the nature of the network is that the load will be redistributed over all the transformers on the network to optimize capacity utilization. Again, as in the case of primary feeders in network areas, this is a collective element of the system.

The second transformer configuration, spot and isolated networks, has different characteristics. They are installed to serve the load of a single customer and sized based on the maximum demand of that customer. As these costs are individual, they are not avoidable through energy efficiency load reductions.

2. Secondary Cable in Network Areas

Secondary cables in network areas connect network transformers and are tapped to provide service to networked secondary customers. They are generally designed for second contingency reliability. As with networked transformers, these facilities are collective and are designed to meet network peak secondary load. CECONY does not believe that a significant number of networks have chronic excess capacity in secondary feeders.

The methodology used here follows that used for network transformers. From the sample of organic load growth and customer notice projects, a unit cost per added kW of effective capacity was developed for secondary cable and associated equipment. Effective capacity is the second contingency load carrying capability and for a segment in equilibrium is equivalent to network peak load. These costs only apply to secondary customers served from network transformers. We show in Table 6 below the Segment-Weighted Marginal Cost and the System-Weighted Marginal Cost. The System-Weighted Marginal Cost uses zero as the weight for marginal cost for non-network load, high tension load and customers served from spot or isolated networks. A reduction in load by one or more customers in the network would free-up capacity that would enable other customers to increase loads and therefore avoid an expansion that the increase would require. Hence these costs are avoidable. As there is no significant excess capacity in this system element, these costs were computed as of the current time and will stay constant in 2011 dollars. The costs are stated in dollars per kW of system peak load.

Table 6. Segment-Weighted and System-Weighted Network Secondary Cable Costs per System kW

	Marginal Cost (2011 $ per kW)
Segment Weighted	63.52
System Weighted	32.52

3. Transformers in Non-Network Areas

In non-network areas, transformers serve a limited group of customers with services that are tied directly to the transformer or to a secondary conductor that is radial from the transformer. Although shared over a limited number of customers, these facilities have characteristics that lean toward meeting individual as opposed to collective demands, and as such are not avoidable through energy efficiency load reductions.

4. Secondary Conductors in Non-Network Areas

In non-network areas, secondary conductors are radial from the transformer and shared over a limited number of customers. These facilities have characteristics that lean toward individual as opposed to collective, and as such, they are not avoidable through energy efficiency load reductions.

IV. ANNUALIZATION OF MARGINAL INVESTMENT COSTS

To develop the annualized distribution marginal costs presented in section III, we first adjusted upwards the investment per unit by an estimate of general plant loading factor that was provided by CECONY. We also included a plant-related A&G loader based on property insurance for distribution substations and transformers, but not lines or other distribution facilities since these are not insured. We then multiplied the resulting figures by the relevant annual economic carrying charges provided by CECONY to yield the annualized plant costs. To these costs we added a revenue requirement for working capital (cash, materials, supplies and prepayments). We estimated the revenue requirement for working capital by applying CECONY's weighted average incremental cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable. CECONY supplied a working capital factor as a percentage of plant. Finally we added an estimate of marginal O&M expenses, previously adjusted by a non-plant loading factor. We developed a non-plant-related A&G loader based on the year 2010 ratio of social security and unemployment benefits, which clearly grow with O&M, to total 2010 O&M less fuel, purchased power and transmission by others.

V. APPLICATION TO ENERGY EFFICIENY EVALUATIONS

As discussed above all costs herein are stated per kW of system peak contribution. Hence, these avoided costs can be applied to the reductions in system peak associated with an energy efficiency program. Note that in order to use these costs, when stated in 2011 dollars, they need to be escalated to nominal dollars for the relevant year. Also subtransmission and area station costs vary by year and the relevant costs need to be aligned with the year that the demand reductions are projected to occur. Finally, these avoided costs apply to incremental energy efficiency programs not reflected in the forecast. The current programs reflecting 450 MW of peak load reductions are included in the forecast and may well have resulted in the deferral of subtransmission and area station facilities, but the impact of those programs is not measured in this study. The avoided costs for each segment are shown below in Table 7. These avoided costs apply to system wide programs targeted at all customers and do not reflect the unique impacts of programs that would be targeted only at customers in a specific location or served form a particular configuration.

Table 7. System-Weighted Marginal Distribution Costs per System kW

System-Weighted Marginal Distribution Costs per kW of System Peak

Year	Area Station and Subtransmission Costs	System Weighted Primary Feeder Costs	Transformer Costs in Network Areas	Secondary Cable Costs in Network Areas	Total
	($ per kW)	($ per kW)	($ per kW)	($ per kW)	($ per kW)
2011	0.42	27.14	16.47	32.52	76.54
2012	5.61	27.95	16.96	33.49	84.01
2013	13.67	28.79	17.47	34.50	94.43
2014	6.87	29.65	18.00	35.53	90.05
2015	43.26	30.54	18.54	36.60	128.93
2016	81.73	31.46	19.09	37.70	169.98
2017	48.98	32.40	19.66	38.83	139.88
2018	125.51	33.37	20.25	39.99	219.13
2019	117.74	34.37	20.86	41.19	214.17
2020	142.83	35.41	21.49	42.43	242.15
2021	124.72	36.47	22.13	43.70	227.02
2022	179.01	37.56	22.80	45.01	284.38
2023	205.98	38.69	23.48	46.36	314.52
2024	189.88	39.85	24.18	47.75	301.67
2025	241.71	41.04	24.91	49.19	356.85
2026	249.07	42.28	25.66	50.66	367.67
2027	256.66	43.54	26.43	52.18	378.82
2028	264.52	44.85	27.22	53.75	390.34
2029	272.58	46.20	28.04	55.36	402.17
2030	280.89	47.58	28.88	57.02	414.37