Electric System Long Range Plan
2011-2031

December 2011
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1.0 EXECUTIVE SUMMARY

1.1 OVERVIEW

For over 150 years, Consolidated Edison, Inc. (Con Edison or the Company) has had the privilege of providing power, light, heat, and cooling to the people of New York City and Westchester County through our electric, gas and steam systems. The Electric System Long Range Plan provides a road map for the electric system for the next two decades. This 2011 update represents the first update of the plan developed in 2010.

Our mission is to deliver safe and reliable electric service to customers in a cost effective, environmentally responsible, and innovative way. This mission entails building and maintaining the electric infrastructure necessary for the transmission and distribution of electricity, procuring energy supply, and providing meter reading, billing and other services to our customers. While we divested almost all of our electric generation plants when New York underwent electric utility restructuring in the late 1990s, we continue to purchase energy supply for our full service customers. Other customers purchase their energy supply directly from energy services companies, but we continue to deliver the electricity they purchase through our transmission and distribution systems.

The past decade has been a challenging one for the Company, as it has been for the nation. The next 20 years is expected to be even more challenging as it is reasonable to expect that the pace of technological and social change will accelerate. It is clear, however, that reliable and cost-effective electric service will continue to be necessary to fuel economic growth and that customer expectations of our performance will only increase. This dramatic pace of change combined with the ongoing challenge of modernizing our electric grid, attracting investors essential for maintaining a substantial investment program, and maintaining reasonable rate levels is why the time to develop an integrated long range plan is now.

Historically, Con Edison developed 10 and 20 year infrastructure plans for its electric distribution and transmission systems, separately. These plans allowed for the system to have sufficient capacity to meet customer energy requirements and were based on stringent design criteria aimed to produce a system that performed very reliably. The Electric System Long Range Plan is a holistic way to effectively integrate transmission and distribution system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources, into one comprehensive plan. We also initiated a comprehensive and quantitative approach to investment optimization for the plan. This enhanced process considers the impact of investments on the performance, cost, and risk profile of the electric system. The plan also provides a framework that links short and long term projects and programs to the Company’s goals and objectives. For 2011, these quantifications have been updated and extended.

The first step in this enhanced planning process is to develop forecasts for electricity demand. We made assumptions regarding potential environmental and regulatory requirements, economic trends, and included possible technological advances to develop three forecasts for potential customer demand: a High Case, Plan Case, and Low Case. For the 2011 update, we stick to the Plan Case, updated for current assumptions. To develop the infrastructure projects and programs in this plan we used the Plan Case demand forecast and identified signposts that we will monitor to test and adapt our plan in the future.

Over the next twenty years we will seek to integrate energy efficiency, distributed generation and
demand response to further our goals of deferring new infrastructure investments and providing safe, reliable, and reasonably priced service that is environmentally responsible. We will provide various methods for customers to manage their energy consumption, expenditures, and to make green choices.

We will implement innovative designs to defer or minimize the investment requirements of new substations, increase asset utilization, and improve the performance of our electric system. These less asset intensive designs will be implemented on a targeted basis as we tailor our engineering and operational approaches to meet the specific needs of the customers we serve. Similarly, we will increase efforts to improve our asset management practices as we continue to move from time-based asset management to a condition-based approach. Advances in communications, similar to those known as Smart Grid technologies, have and will continue to give us greater visibility into the status of our system components, allowing us to increase system automation, improve the accuracy of our predictive system models, and direct us to those system components that need the most attention, all with the goal of reducing our total costs.

In the next twenty years we expect to invest $26 billion in capital infrastructure in real 2011 dollars, or an average of $1.3 billion a year. At this level of expenditure, along with projected increases in the cost of supply, we expect that a typical New York City residential customers’ monthly bill for electricity, in real 2011 dollars would increase from $81.40 today to $88.15 in 2031, an average compound annual growth rate (CAGR) of 0.4%.

The projected bill reflects the impact of higher infrastructure replacement costs, higher energy costs, as well as rising service fees and taxes. Replacing components of our electric grid, which have a low average cost due to the vintage of equipment, with a much higher replacement cost will necessarily cause the cost of providing service to increase. We are sensitive to the impact of rate increases on our customers and we will work very hard to keep costs down. Concurrently, we also need to address the needs of service reliability, system safety, and regulatory requirements to maintain the critical electric infrastructure that supports the economic viability and security of New York City and Westchester County.

Over the past twenty years, we have been successful in keeping the real price of electricity flat, on par with general inflation in the economy. Although there is no assurance that this pattern will continue, in the next twenty years we are determined to achieve the maximum efficiencies from operating our system to meet our commitments to our customers and investors. We will strive to achieve efficiency gains beyond the estimates in this long range plan.

Our plan outlines important opportunities to realize the potential for moderate cost increases, including potential regulatory, tax, and related reforms and utility ratemaking approaches that would increase the relative value of electric service.

1.2 KEY ELEMENTS OF THE PLAN

Demand and Supply

We must ensure that our transmission and distribution systems have sufficient capacity to meet customers’ peak electricity demand and that we can procure adequate energy supply for our customers. We originally developed three potential forecasts to assess the impact of various economic, legislative, and technological drivers on customer demand for electricity. This update
focuses on the middle case, called the Plan Case.

The annual peak electricity demand in the Company’s service territory is shown in Figure 1-1 for the Plan case.

Figure 1-1. Peak Demand Forecast

The Plan Case, which provides the basis for our Electric System Long Range Plan, assumes moderate economic growth, coupled with a continued increase in customers’ use of electricity, offset by improved energy efficiency measures and stricter codes and standards. This forecast is consistent with the New York Independent System Operator’s view of the future. Electricity demand in New York City and Westchester County rises on average at approximately 1.1% per year and represents a 25% increase in electricity demand over the 20-year planning horizon.

Peak demand, or the maximum electricity that our customers require at a single point in time, drives infrastructure investment because our system must be able to meet that demand even if it is a relatively infrequent occurrence. In our service territory, these peak demand periods occur only during the hottest periods of the summer, often for only several hours over the span of a few days. One goal embodied in the Electric System Long Range Plan is to implement customer-focused programs, such as demand side management, that can reduce the system peak, thus deferring infrastructure investments and lowering customer bills.

Supply costs are also a major component of our customers’ bills. Although Con Edison does not own significant sources of electric supply, we continue to procure electricity for our full service customers and those costs are part of their electric bill. Our assessment of the electricity supply market suggests that the cost of supply, in real 2011 dollars, will increase at an annual rate of 1.2% over the 20-year time horizon. On a per kilowatt-hour (kWh) basis that represents an increase from 9.0 cents per kWh in 2011 to 11.2 cents per kWh by 2031.
In order to keep our electric service reasonably priced while furthering our goals of safe, reliable and environmentally responsible service, we plan to work closely with our customers to actively manage both demand and supply. Demand side management, for example, may defer or eliminate the need for additional capital infrastructure, while at the same time reducing greenhouse gas emissions. Similarly, the integration of distributed supply solutions and the well planned off-peak integration of electric vehicles in our service territory may mitigate the need for large capacity upgrades, improve reliability, and reduce our reliance on fossil fuel resources.

Over the next twenty years we expect to deploy a full portfolio of programs to actively manage customer demand, diversify supply sources, and improve our overall environmental profile. The major initiatives we will offer in this portfolio are to:

- Expand our role as an energy advisor to customers to aid them in managing their energy expenditures through energy efficiency demand response programs.
- Facilitate and integrate distributed generation to provide choices for customers and increase the penetration of clean distributed generation, including renewables such as rooftop photo-voltaics, through customer and utility owned applications with benefits for the electric system.
- Support new infrastructure to facilitate plug-in electric vehicle deployment (and other emerging end-use applications) and potential storage and vehicle-to-grid applications through a series of pilots, working with industry associations, manufacturers and customers. Our objective is to pace these infrastructure investments and initiatives in such a way that does not overbuild or create stranded assets.
- Potentially invest in the cost-effective deployment of an advanced metering infrastructure (AMI) for the implementation, measurement, and dispatch of the aforementioned demand- and supply-side resources.
- Seek to incorporate renewable supply sources into the grid, including developing partnerships to investigate new technologies and building new transmission lines where necessary for reliability or which are the most cost-effective solutions (compared to generation or demand side management).
- Continue to deploy a portfolio of environmental sustainability initiatives to improve Con Edison’s environmental impact in all aspects of our business.

**Transmission & Distribution Infrastructure**

Our electric system consists of over 1,100 miles of underground transmission cable and overhead transmission lines supported by over 1,200 transmission towers. Our transmission system supplies power to 39 transmission substations which, in turn, supply 62 area substations. Approximately 2,270 primary distribution feeders come from these areas substations, feeding 27,000 underground distribution transformers in our 64 networks and 50,000 pole-mounted transformers in our overhead areas. These assets, among others, represent billions of dollars of investment requiring maintenance, repair, and replacement.

The Plan Case demand forecast shows an increase in demand over the planning horizon of 25%. To meet this demand, we would need to build six new substations at the transmission or sub-transmission level to accommodate six new distribution networks across our service area. In addition to this major substation work, we would need to implement associated equipment and cable transfers and
expansions in local areas of the distribution system.

Plan Initiatives

It is imperative that we manage our existing infrastructure, and expand it as required, in a cost-effective manner. The 20-year plan details initiatives which challenge and fundamentally change key aspects of our current design criteria, moving us from a prescriptive and deterministic engineering design basis to one that is driven by a probabilistic approach. We actively integrate targeted demand and supply side management programs, innovative designs, advanced technologies, as well as traditional designs to implement tailored, “best fit” solutions. And, we enhance our asset management practices to optimize maintenance expenditures, effectively moving from a time-based to a condition-based approach.

Over the course of this plan, we intend to meet our service reliability objectives in less asset intensive ways through the implementation of innovative third generation (3G) designs. The first generation design, implemented during the initial construction of the electric system, was characterized by radial overhead construction. The second generation design moved much of the infrastructure underground and provided for more reliable service through multiple supply paths. Our newest generation of designs, or 3G, leverage asset sharing approaches and are enabled by enhanced system monitoring and advanced underground switching. 3G designs are a critical component of our strategy to defer or minimize the investment requirements of new substations, increase asset utilization, reduce cost and improve the performance of our system.

3G designs have the potential to result in significant savings in capital investment because they provide the ability to increase system capacity incrementally. This allows us to defer large capacity investments by closely matching relatively small increases in system capacity to customers’ growing demand for electricity as it occurs. The 3G designs also increase the utilization of our existing asset base, deferring a portion of the need for new infrastructure investment. We know our customers value high reliability and 3G design concepts were created with the goal of maintaining our reliability levels by considering the probabilities of simultaneous system component failures. Over the 20-year horizon, we plan to implement several 3G concepts, including the installation of transferrable feeder groups, virtual substations, intelligent underground autoloops, and automatic primary feeder switches. Each will serve to advance the achievement of our infrastructure investment objectives and will be used to further reduce customer cost increases.

In addition to implementing new design concepts, we will employ a more integrated approach to overall system investment. Various demand and supply management programs will reduce demand on the constrained parts of our system, thus reducing infrastructure expansion and reinforcement expenditures. When system expansion is required, however, our strategy is to pursue solutions to satisfy electric system goals. These solutions will apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas.

The need to maximize utilization and performance of our existing assets and to optimize maintenance expenditures makes strong and effective asset management essential. An effective asset management program affects maintenance patterns, repair and replacement decisions, as well as overall electric system planning and design. Greater precision in identification of the right time to add or replace an asset allows the best directed use of capital and operations and maintenance expenditures. In addition, information on operating conditions allows planners and operators to
optimize system configurations when evaluating network reinforcements and replacements.

Our planned asset management programs and processes consider the performance, cost and risk profiles of components that, collectively, make up our electric transmission and distribution system. We use various methods and tools to monitor, analyze, assess and control our assets to obtain optimal performance of our electrical components, asset classes and overall system. The information we capture, trend, and analyze allows us to evaluate and compare the performance across various components or asset classes so that we are targeting our programs in the right places and, therefore, optimizing what we spend on our asset maintenance, repair, and replacement decisions.

As we add more advanced monitoring on our components we will be able to continue to move away from time-based to condition-based maintenance. By gathering and analyzing data from in-field sensors we are better able to understand performance trends on specific asset classes. This may allow us to alter maintenance cycles, increase the life of various components, improve the design of specific assets, and predict and prevent failures.

The effectiveness of our modeling capabilities is closely related to the quality and accuracy of the data and information we have about the performance of the electric system under a variety of customer demand conditions. We continue to develop and implement effective system monitoring to improve this information base. We are also implementing various Smart Grid technologies which may provide greatly enhanced control over the grid, more control of electricity use by our customers, and better system performance. Figure 1-2 illustrates the key elements of the Company’s planned Smart Grid implementation.

**Figure 1-2. Elements of a Smart Grid**

*Smart Grid*

Smart Grid puts information and communication technology into electricity generation, delivery, and consumption, making systems cleaner, safer, and more reliable and efficient.

*Smart Building Technology* including web portals and in-home displays will eventually allow customers to track their energy use and give them the tools to change their energy-using habits, including the ability to remotely control appliances.

*Greener Energy Sources* are more readily integrated into the smart distribution grid.

*Intelligent Underground Systems* use sophisticated communication technology to monitor, isolate, and correct problems and improve reliability.

*Plug-In Electric Cars* can connect to the grid to charge, and one day may even provide power from their battery packs when the cars are not in use.

*Smart Meters* gather information about customers’ energy use so customers can use electricity more efficiently, and the meters may enable the utility to identify system problems.

*Customer Energy Generators* enhance system reliability.
Smart Grid is an industry term that generally describes how customers and the utility will have more information and control over various aspects of electricity usage and system performance through the application of advanced monitoring and technology.

Our Long Island City Pilot announced in July 2009, is the Company’s most comprehensive Smart Grid application and includes the installation of Advanced Metering Infrastructure devices, home area networks, solar panels, remotely controlled feeder switches on underground feeders, and transformer and network protection monitoring. In addition to the Long Island City Pilot, the Company filed two grant applications for Federal stimulus funding with the U.S. Department of Energy. Con Edison’s Smart Grid Investment Grant and Demonstration Project were approved for $181 million.

The Company expects a wide range of benefits to accrue from our Smart Grid initiatives, including the proof of concept of new wireless monitoring and control technologies, vast new data collection opportunities on distributed supply and customer demand patterns, and secondary model validation from the increased demand and power flow data. We anticipate that the change in information and telecommunication technologies will continue to help reduce the overall cost and improve the performance of our electric system. Our long term objective is to develop a smarter grid that will capture the full benefits of improved and additional monitoring, modeling, and control.

*Infrastructure Costs*

Each of the near and long term projects and programs discussed above was designed to help us achieve our goals to provide our customers with the consistent high reliability performance they have come to expect at a reasonable cost.

By utilizing improved asset management practices through enhanced monitoring and control, Con Edison can defer significant capital investment. We expect to realize about $600 million in capital savings from these efforts. For certain substation investments that are required to meet system demand, Con Edison plans to adopt 3G design techniques which will reduce overall costs by an additional $3.6 billion. Additional opportunities for savings will be continually and aggressively pursued.

The Company’s overall capital investment profile, shown both gross and with the expected savings described above, is presented in Figure 1-3. The figure highlights that we estimate capital expenditures would have been more than $30.1 billion without the savings discussed above. Our forecasted expenditures are about $26 billion over the entire planning horizon, or an average of $1.3 billion per year in 2011 dollars.
Figure 1-3. Con Edison Capital Expenditure (2011-2031)

Cumulative Capital Investment Expenditures – 2011-2031
The total capital investment plan, which will be an ongoing focus for spending mitigation opportunities, is the aggregation of the expected expenditure levels across six major functional areas. The individual spend patterns for each of these functional areas is highlighted in Figure 1-4.

**Figure 1-4. Annual Capital Expenditure Plan by Category (2011-2031)**

![Annual Capital Expenditure Plan by Category (2011-2031)](image)

**Table 1-1. Cumulative Capital Expenditure by Category**

<table>
<thead>
<tr>
<th>Category</th>
<th>Cumulative Expenditure ($, million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interference</td>
<td>894</td>
</tr>
<tr>
<td>System Expansion</td>
<td>10,937</td>
</tr>
<tr>
<td>Other</td>
<td>952</td>
</tr>
<tr>
<td>Reliability</td>
<td>5,958</td>
</tr>
<tr>
<td>Replacement</td>
<td>4,491</td>
</tr>
<tr>
<td>Common</td>
<td>2,769</td>
</tr>
</tbody>
</table>

The savings in infrastructure costs described earlier are reflected in Figure 1-4. Reliability and replacement investments are $600 million lower over the twenty years due to aggressive asset management enabled by improved monitoring and control capabilities. In addition, system expansion investments are $3.6 billion lower over the planning period because of savings from the implementation of 3G substation designs.

**Customer Bill**

We will continue to seek to help customers control their energy costs while maintaining the highest levels of service reliability and system safety. The estimated impact of our planned investments, along with projected cost increases to the supply and tax portions of the bill, is expected to increase annually from 2011 to 2031 by approximately 0.4% on a real basis. The total increase broken out by bill component is illustrated in Figure 1-5.
This analysis incorporates a number of cost saving initiatives totaling $4.2 billion in capital savings. Notwithstanding the significant challenges of maintaining rate increases at inflationary levels, particularly in the absence of currently unforeseen innovations or cost avoidance measures, we are committed to keeping costs down. We are also committed to rigorously pursue regulatory and tax reforms.

1.3 PLAN PERFORMANCE

The Electric System Long Range Plan includes major investments in our electric system, specific programs to maintain and upgrade it, and various initiatives to manage customer demand for the benefit of customers and the environment. To support the development of the original plan, we created a capital investment database and analytical model to evaluate the impact of programs and initiatives. Capital investment projects were evaluated for impacts on performance, risk, and cost characteristics of the electric system. This analysis is consistent with the Company’s asset management practices, annual capital expenditure prioritization process, and our focus on enterprise risk management.

Through our engineering designs, work practices, and system investment, we have placed a high priority on delivering power reliably. Figure 1-6 illustrates a relative comparison of Con Edison reliability vs. national and New York State levels.
Our investment plan allows us to maintain our high level of service reliability as we continue to upgrade our systems and leverage new technologies, designs, and practices. As shown in Figure 1-6 our overhead system is more than twice as reliable as the rest of the state and nearly three times as reliable as the rest of the nation. On average, a customer served by our overhead system experiences an interruption less than once every two years. Our underground network system reliability performance is very strong, yielding superior day-to-day reliability. On average, a customer served by our underground network system experiences a service interruption nearly once every sixty years excluding major events like a hurricane or other excludable outages. Across the entire system, we expect customer interruptions to be no higher than the performance in 2008, which were 130 interruptions per 1,000 customers per year. Maintaining these levels of reliability is critically important to us as our customers consistently tell us that reliability is their number one priority.

In addition to maintaining these levels of day-to-day reliability, we seek to reduce the risk of a prolonged, large-scale network outage, and the resulting adverse impacts experienced by our customers. Con Edison has developed and utilizes analytical models to understand the performance of each of our networks based on their unique characteristics. The key output from these models, the Network Reliability Index (NRI), is a probabilistic measure of risk levels of each network. NRI is defined as the state where four or more feeders supplying power to one local portion of a network experience failure at the same time during periods of high electricity demand. NRI has become an important planning measure that the Company uses in a variety of design and investment decision-making processes.
Investment in three targeted capital programs directly reduces NRI risk: removal of PILC, the installation of sectionalizing switches on network feeders, and increasing the number of primary distribution feeders serving a network. Our goal is to apply focused program investment to decrease risk on networks where the investment will have the greatest impact. Based upon the application of these programs, at average annual investment of $46 million from 2011 through 2016, we estimate a 45% improvement across our relatively riskiest networks. In the 2015 time-frame, the three NRI programs described above will reach points of diminishing returns and as a result, a re-evaluation of our approach in this area will be required in 2016 to carefully weigh risk reduction benefit against the cost, and against new tools, programs, or innovations that may be available.

We measure the environmental impact of our plan by the reduction in greenhouse gases. Figure 1-7 summarizes the environmental improvements that result from the investments and sustainability initiatives in the Electric System Long Range Plan.

**Figure 1-7. Target Environmental Emissions (CO₂e) Reduction by 2031**

The largest contributor to greenhouse gas reductions from Direct CECONY Initiatives is our effort to continually reduce sulfur-hexafluoride (SF₆) emissions. SF₆ is used as to extinguish the arc of current present within a circuit breaker when it is opened under load, and as an insulating medium in different pieces of equipment such as in enclosed bus arrangements. As it has been identified by the Intergovernmental Panel on Climate Change as a potent greenhouse gas, the Company has committed to the Environmental Protection Agency to reduce SF₆ emissions annually by 5% from the 1996 baseline. Customer Reductions include the expanded availability and interconnection of renewable energy and the implementation of demand side management programs.

A factor of pivotal importance to us is the safety of the public we serve and of our employees that make these services possible. Over the past several years we have made improvements in our ability to maintain a safe environment for both the public and our employees. Our goal is to continue to improve in these critical areas. We recognize it is impossible to forecast the number of safety incidents that will occur in a particular year but our goal is to minimize incidents and to track and analyze those
incidents that do occur in an effort to continuously improve. Our goal for employee safety is to reduce our OSHA (Occupational Safety and Health Administration) Incidence Rate to 1.5, or approximately 1.5 injuries and illnesses per 100 workers by 2015, from 3.22 in 2009 and 2.48 in 2010, putting us in the top quartile among industry peers. As we continuously improve our culture to embrace learning from our experiences and achieving personal and organizational bests, we would seek to maintain or improve that performance over the entire planning horizon.

1.4 UNCERTAINTIES AND SIGNPOSTS

By definition uncertainties are difficult to predict. For the purposes of this plan, we describe two forces that we deem to be potential “game changers”: the pace of technology innovation and the nature of regulation and legislation. Of course, we recognize the uncertainty of the economy will add variability to forecasting.

Our plan was developed under considerable uncertainty including emerging technologies, energy and environmental regulations, customer demand, availability and cost of fuel supplies, economic conditions, availability of financing, and utility regulation and ratemaking approaches. These uncertainties persist even though we have the significant benefit of the recent issuance of the New York State Energy Plan. This State Energy Plan, for the first time in many years, prescribes and affirms State energy policy and provides substantial policy guidance for utility companies, facilitating preparation of this Electric System Long Range Plan. We realize that with the passage of time, the nature of these uncertainties will change and new uncertainties will emerge. As such, the plan is intended to be a flexible, living document that will be monitored and reshaped as circumstances change.

Technological Uncertainties

Three areas of technological uncertainty that most affect our future are customer end-use, Smart Grid delivery and control technologies, and the cost of electricity supply. Innovations in lighting, air conditioning, motors, building controls and automation may decrease demand, but the sheer volume of new electric devices and new applications such as electric vehicles may increase demand. Smart Grid is predicted to bring advances in the delivery, control and availability of granular usage information that may be used to engage more customers in the efficient use of electricity and may lead to changes in our asset management practices. Clean distributed sources and distributed storage technologies may offset transmission and distribution infrastructure investments and reduce greenhouse gas emissions.

From a planning perspective, it is difficult to predict how quickly particular innovations will develop or whether they will experience widespread adoption. For the future, we will plan for both major breakthroughs as well as incremental advances in these three areas of uncertainty. The plan provides multiple “signposts” to signal when and where assumptions should be updated due to advances in technology.

Regulatory and Legislative Uncertainties

Energy issues are central to many of the current environmental, economic, and security debates occurring at all levels of government. Energy and environmental policies are under ongoing review and we cannot know with certainty what specific regulatory proposals will be adopted or what revisions will be made even in the near term.
This plan primarily incorporates and extrapolates the requirements in the New York State Energy Plan as well as pending Federal legislation and New York City plans. Since the plan describes multi-year, intensive capital investments on a vast network, rapid and large shifts in cost or revenue would be disruptive. Examples of the regulatory and legislative signposts related to such change are high taxes and imposition of more stringent environmental requirements. As such, regulatory reform, including tax reform is essential if the company is to succeed in moderating projected increases in the cost of electric service. For example, reforms that will facilitate off-peak charging for electric vehicles will be important to achieve the investment levels indicated in the plan, and not achieving that could result in increased needs if electric vehicles are widely adopted over the planning period.

**Economic Uncertainties**

The population and economy of the New York City metropolitan area are the primary drivers of our projections for energy use and demand. Increases in population, employment and overall economic growth drive increased energy usage and amplifies the pace of investment, while slower or negative growth has a contrary effect. The impacts are not symmetrical in that negative growth still would not eliminate the need to replace existing facilities serving the existing customer base.

Our goal is to provide safe and reliable energy at an affordable price to our customers. Our electric system is one of the most heavily relied upon in the world. Over three million customers depend on us every day for safe and reliable power. We are responsible for serving the financial and media capitals of the world, critical infrastructure including tunnels and subways, and more hospitals per square mile than any other city in the world. To meet these demands, we challenge ourselves to continually improve the design and operation of our electric system.

**1.5 SUMMARY**

Our Electric System Long Range Plan is a key step for serving our customers with safe and reliable power. It provides a strategic framework for implementing our plans to manage demand and supply, invest in our infrastructure, provide environmental stewardship, and to serve our customers at a reasonable cost. Over the planning horizon, some pilot programs will produce positive results, some uncertainties will be resolved, and other uncertainties will surface. It is because of this uncertainty that we must plan ahead.

General Eisenhower once said “plans are useless, but planning is essential.” In the process of developing a plan, a planning organization expresses desired outcomes, identifies unknowns, and enhances our corporate ability to address contingencies and to adjust to new and unforeseen developments when they inevitably arise. We have developed a long range planning process to monitor signposts and adjust the plan as needed.

We developed this long range plan to guide us into the future and provide us with a road map to progress for the next two decades. We have described the various uncertainties, identified key signposts and we expect to update the plan as fundamental changes occur in our operating environment. We will measure our performance, manage our costs and reduce the risks on our system. The way we will accomplish all of our goals is to work collaboratively with our customers, legislators, regulators, community leaders and others in order to implement our plan successfully.

This plan is consistent with our mission to deliver safe and reliable electric service to customers in an innovative, cost effective, and environmentally responsible way. “Safe and reliable” energy service is
a phrase that is embraced by all of us at Con Edison. Our vision is to lead and support efficient electric energy practices in the communities we serve by continuously improving our electric systems and processes with smarter, high performing electric networks, better information management systems and highly qualified employees. Our commitment is to meet our customers' expectations. We will do so by managing demand, supply, and protecting our environment. We will integrate our system design to meet the needs of customers in specific areas and improve our asset management through optimal use of our assets. We will extend the life of our system if feasible and minimize capital investments so that we will be well positioned to serve today and in the future.

It is in these ways that we expect to successfully carry out our objectives and implement our long range electric plan.

***
2.0 INTRODUCTION

2.1 VISION, MISSION AND PLAN OBJECTIVES

A clear vision for our future and well-defined mission for our operations are necessary to guide our decisions for investments and programs in the 20-year planning period. The Con Edison Electric System vision statement is as follows:

*We will meet New York City and Westchester County’s electric energy needs by continuously improving our electric systems and processes with smarter, high performing electric networks, better information management systems and highly qualified employees meeting customer expectations for safety, reliability and reasonably priced electric service.*

New York City is already one of the most energy efficient cities in the world. With such a dense population in a small space, the average monthly use of electricity per customer in the city is amongst the lowest in the nation. A typical New York City apartment dweller uses only 3,600 kWh per year versus the national average of over 11,000 kWh.\(^1\) The New York metropolitan area also maintains the nation’s largest electric powered subway system and three major electric powered commuter railroads to neighboring communities.

Our service territory is a critical commercial center, making reliable electric service of utmost importance. Con Edison's customers create about 9% of the United States’ Gross Domestic Product\(^2\). Our economy is largely based on information-intensive enterprises which are highly dependent on power quality and reliability. Any significant decline in reliability would pose a high cost to our local businesses.

Our region is home to the headquarters of over 50 Fortune 500 companies. Some of our most famous customers include the New York Stock Exchange, the Federal Reserve, the United Nations, Rockefeller Center, and the Empire State Building. We serve world-renowned cultural and media institutions like Lincoln Center, the Metropolitan Museum of Art, the Museum of Modern Art, the Guggenheim, Carnegie Hall, Radio City Music Hall, and the Apollo Theater. We are home to two major league baseball teams that play at the new Yankee Stadium and Citi Field and we host multiple sporting and cultural events at Madison Square Garden. Our Times Square neighborhood is home to forty Broadway theaters\(^3\), too many restaurants and hotels to count, and hosts nearly 40 million tourists per year\(^4\).

In our service territory alone, there are over eighty public and private hospitals, more than one-hundred and thirty emergency and relief services locations, and over two-hundred community care facilities for the elderly. There are also over one-hundred and fifty colleges and universities across the six counties within our service territory.\(^5\)

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\(^1\) Energy Information Administration. 2010.
\(^2\) Bureau of Economic Analysis. 2011.
\(^3\) ILoveNYTheater.com. 2011
\(^4\) The Times Square Alliance. 2011.
In addition to the largest subway infrastructure in the nation and the commuter rail lines mentioned above, we serve three airports including two major international airports that serve over 73 million passengers each year on 1,700 domestic and 470 international flights daily.

On an individual basis, the lifestyle of this densely populated region is powered by electricity, which enables 24-hour and high-rise living, and promotes neighborhood safety. We serve over 6,000 buildings with greater than 12 floors. Our customers benefit from an extensive electrically powered, public transportation network that is distinguished from other major metropolitan systems by its size, 24-hour convenience, and widespread use. Perhaps no area in the world receives a greater financial and societal benefit from highly reliable electricity. And there may be no area which has higher expectations of reliability.

We know New York City and Westchester County will continue to grow and change. Con Edison will continue to power existing infrastructure and business while watching for what is to come for future generations. We envision a future where there is a continued and growing demand for electricity driven by an ever increasing proliferation of electricity powered appliances, communication devices, home controllers, and even transportation equipment such as electric vehicles. While appliance and building codes and standards will continuously improve the efficiency of electronic gadgets, the sheer increasing number and use of these devices will solidify the need for both the central plant and distributed utility grid model, as well as the need to incorporate newer renewable and clean distributed resources to reduce our dependency on fossil fuels and additional, expensive infrastructure.

We see a future with increased need for integrated planning at the utility, local, state and federal levels, and even greater dependence on the sound engineering competencies that brought us to this time in our evolution. We support continued development of competitive markets where they make sense. Cleaner and more efficient technologies will drive demand, but will always need to be balanced by cost. When new technologies are the obvious low cost choice only then will they survive and consequently thrive in the marketplace. Our jobs in the future will entail a more integrated systems approach where more and more information will need to be collected, analyzed, and acted upon to keep the system operating at optimal levels.

To get us from here to there, Con Edison has further defined its strategic mission to align near-term objectives with our longer term vision. Our mission to deliver the benefits of safe and reliable electric service to customers in an innovative, cost effective and environmentally responsible way, serves as a touchstone for our planning and decision-making processes. The Company’s core commitment is to deliver safe, reliable, and cost-effective electric service to New York City and Westchester County and this is the foundation for all of our actions. Con Edison pursues these goals with the ultimate objective of positively contributing to the total living environment for all metropolitan New Yorkers, which includes the economic, security, and environmental well-being of the entire community.

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6 Port Authority of New York and New Jersey, 2011.
We developed five objectives to guide the development of the Electric System Long Range Plan. These plan themes collectively carry out our mission and individually describe areas of Con Edison’s strategic intent by which individual programs and investments are categorized. Figure 2-1 illustrates how the objectives support the Con Edison vision and mission.

**Figure 2-1. Con Edison Vision, Mission, and Plan Themes**

![Diagram](image)

**Managing Demand, Supply, and Environmental Profile**

Con Edison will take a proactive and integrated approach to managing demand, supply, and environmental impact. We will encourage demand side management to reduce peak demand and overall energy use and will support the development of highly efficient codes and standards. We will facilitate the interconnection of distributed generation and carefully plan for new circuit-level load from new technologies such as electric vehicles. Our plan includes the maintenance of a balanced, reasonable-cost supply portfolio and we will explore opportunities to efficiently connect additional renewable and other sources of affordable generation and transmission developed in the market. We expect to invest in cost-effective advanced metering where necessary to support these initiatives.

**Integrating Innovative System Design**

The deployment of a targeted approach to meeting electric system capacity, reliability, and replacement needs will improve asset utilization; reduce major risks; and lower costs. We will incorporate new designs and advanced technologies into our traditional capacity and reliability solutions at the network, feeder, and component level.

**Improving Asset Management and Control**

Con Edison will focus on efficient management of transmission and distribution assets. We will use innovative maintenance practices, monitoring tools, and control technologies. We will continue efforts to manage the costs of infrastructure construction and integrate new communications technologies, such as Smart Grid applications, into future asset management protocols as they evolve.
2.2 PROCESS OF DEVELOPING THE ELECTRIC SYSTEM LONG RANGE PLAN

Our process of developing this integrated Electric System Long Range Plan includes careful considerations for the questions listed below:

- What are the key drivers impacting the electricity marketplace?
- How will various elements of electricity consumption be impacted by the key drivers?
- What are the resultant electricity growth cases for our service territory?
- How do we design our systems, build new infrastructure, and maintain existing assets to meet evolving customer needs?
- What are the implications of the various electricity forecasts on our customers’ bills, both from our transmission and distribution plan as well as other potential impacts on their bill such as the cost of supply?

As depicted in Figure 2-2 we developed hypotheses regarding the key drivers, projected the implications of various uncertainties on electricity demand, energy use and electricity supply, and developed three electricity growth cases. From here, we conducted a thorough review of our methods of system design and our plans to maintain and build assets. Plans were shared with stakeholders and tested for total customer bill impact.

Figure 2-2. Process for Developing the Electric System Long Range Plan
To identify, assess, and prioritize business unit activity, we engaged in a comprehensive review of business unit plans and evaluated the merit of incorporating emerging ideas into the integrated plan. Throughout this planning process, plans were adjusted to ensure that collective organizational activities will fulfill our mission and optimize our performance against a framework that considers performance, costs and risks.

We expect that by 2031 the electric usage landscape will look very different than it does today. All potential initiatives were tested as to their relevance based on new transmission and distribution and end-use technologies, emerging legislative requirements like renewable portfolio standards, and continual changes in customer expectations. For example, several programs and technologies such as distributed generation, advanced metering infrastructure (AMI), and various Smart Grid applications were assessed in terms of their potential to increase performance, reduce costs, manage risks, and allow the Company to prepare for the electric needs of customers in the future.

In order to ensure the plan was truly integrated across all business units, the planning process required collaboration across the entire organization. Each of the organizations depicted in Figure 2-3 was integral to the process.

**Figure 2-3. Con Edison Organization Chart**

2.2.1 Electricity Forecast

The electricity forecast drives the timing and magnitude of the required investment in transmission and distribution infrastructure. Con Edison currently develops 10-year load forecasts to ensure that transmission and distribution infrastructure is adequate to support the economic growth of New York City and Westchester County. To develop the 20-year forecast for the Electric System Long Range Plan, we extended the existing forecast based on a number of key driver sensitivities.
A standard forecast consists of two components: an energy forecast and a peak demand forecast. The energy forecast is a projection of electricity consumed throughout the year, measured in gigawatt-hours (GWh). The peak demand forecast is a projection of the maximum electricity requirements that Con Edison’s customers demand at a single point in time, measured in megawatts (MW). Peak demand, or the maximum electricity that our customers require at a single point in time, drives infrastructure investment because we must build to that demand even if it is a relatively infrequent occurrence. For the Con Edison electric system, peak demand occurs in summer when air conditioning loads are the highest.

The primary driver of energy demand is economic growth, which affects employment, construction and population growth in our service territory. Another important driver is environmental and energy policy and regulation, which influences customer rates and mandates certain utility programs. Innovations and price changes in end-use technology (e.g., flat screen televisions, electric vehicles) also affect customer energy use.

The Plan Case forecast for energy and demand is described in brief below and depicted graphically in Figures 2-4 and 2-5.

- **Plan Case**—Based on economic growth consistent with current expectations, with modest load growth in 2012 followed by consistent annual energy growth around 1.0% and annual demand growth of approximately 1.14%. The Plan Case is the basis for all initiatives and assumptions discussed in the plan. This case incorporates demand side management consistent with New York Independent System Operator assumptions, which estimate that approximately 30% of New York State’s goal of 15% reduction in energy by 2015 is achieved.

![Figure 2-4. Energy Forecasts](image-url)
2.2.2 Stakeholder Input

During the original development of the Electric System Long Range Plan, Con Edison met with a representative group of stakeholders, including New York City, and the New York State Governor’s office. We also had frequent discussions with the Public Service Commission Staff. In the future, we expect to continue to have discussions with key stakeholders about our plans.

We also engaged in a targeted customer outreach effort. We organized focus groups of residential and small commercial customers in New York City and Westchester County and conducted one-on-one interviews with large commercial customers. Outreach topics covered affordability, reliability, energy efficiency, renewable power, infrastructure upgrades, and the pace of adoption of new technologies. Customer feedback was considered and incorporated in the plan.

2.2.3 Evaluation of Investments Based on Performance, Cost, and Risk

The overall management challenge of effective planning is to manage the network in an optimal way to balance the often competing priorities of cost, performance, and risk. The Company’s strategic priorities and specific initiatives are designed to improve one or more of these attributes, and make informed trade-offs. For example, increasing reliability or reducing risk is desirable but could increase new capital expenditures or investment in additional operating programs. Consequently, the themes of performance, cost, and risk must be balanced in a systematic and appropriate manner.

As part of our effort to prepare the original plan, we developed a capital investment database and custom analytic model to systematically evaluate the impact of specific programs and initiatives over the 20-year planning horizon. The forecasted capital investments were each evaluated in terms of their
incremental impact on the performance, cost, and risk characteristics of the Con Edison electric system. The performance measures are system reliability and environmental impact. The cost measures are capital, operations and maintenance expenditures, and savings when compared to existing or traditional solutions, as well as the rate and bill impact of those investments. Risk reduction is measured within the model based on the network reliability index (NRI) and outside the model with various public and employee safety initiatives. These measures are consistent with the Company’s asset management practices, annual asset prioritization process, and Con Edison’s enterprise risk management (ERM) process. The Company believes the estimates in this 2011 update of the plan are reasonable and their implications therefore warrant careful consideration and should be taken as indicative of an important need to develop strategies to mitigate the cost increases indicated by the plan. Each of these facets of the Company’s planning and prioritization methods will be described in more detail in subsequent chapters.

2.3 BACKGROUND ON CON EDISON

2.3.1 Service Territory

Our electric service territory is composed of over 600 square miles with 9.3 million residents located in the southernmost part of New York State and includes New York City (except the Rockaway Peninsula) and most of Westchester County, as shown in Figure 2-6.

Table 2-1 shows the size of the areas we service in the five boroughs of New York City, as well as Westchester County, along with the number of customers in each of these areas.
### Table 2-1. Service Area Statistics

<table>
<thead>
<tr>
<th>Service Area</th>
<th>Square Miles of Service Area</th>
<th>Customers&lt;sup&gt;7&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bronx</td>
<td>41</td>
<td>426,026</td>
</tr>
<tr>
<td>Brooklyn</td>
<td>70</td>
<td>905,705</td>
</tr>
<tr>
<td>Manhattan</td>
<td>23</td>
<td>719,539</td>
</tr>
<tr>
<td>Queens</td>
<td>108</td>
<td>747,927</td>
</tr>
<tr>
<td>Staten Island</td>
<td>58</td>
<td>174,202</td>
</tr>
<tr>
<td>Westchester County</td>
<td>310</td>
<td>347,403</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>610</strong></td>
<td><strong>3,320,802</strong></td>
</tr>
</tbody>
</table>

#### 2.3.2 Electric System

Electricity is produced at generating stations and then delivered to customers via a transmission and distribution network. Con Edison is primarily a transmission and distribution company.<sup>8</sup> The infrastructure of a delivery system consists of the transmission system, substations, and the distribution system. These basic elements of the Company’s transmission and distribution system are illustrated in Figure 2-7.

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<sup>7</sup> Number of customers is determined based on number of electric meters.

<sup>8</sup> Con Edison owns less than 5% of the generation assets supplying its customers; the remaining 95% of generation assets is owned and operated by market suppliers.
Figure 2-7. Illustration of Con Edison Electric System

The CECONY Electric System

Generating Station
Most stations supplying the CECONY System are owned and operated by other companies

Transmission Substation
Voltage is stepped up for transmission

Transmission Lines
Overhead and underground transmission lines carry power to area substations

Area Substation
Voltage is stepped down by power transformers

Overhead System
Overhead Distribution Transformers
Voltage is stepped down for distribution to residential and commercial customers by transformers attached to poles

Underground System
Underground Distribution Transformers
Voltage is stepped down for distribution to residential and commercial customers by underground transformers

Residential and Commercial Customers
**Generation**

Following restructuring in the 1990s, the majority of the electricity generated for supply to our customers is now owned and operated by other companies. We primarily purchase our customers' energy requirements through a combination of daily market transactions and longer-term contract arrangements. Con Edison, Inc. does operate a small number of electric generating facilities consisting of plants located in New York City with an aggregate capacity of 700 megawatts (MW).

**Transmission**

Con Edison’s transmission infrastructure consists of conductors that carry transmission voltage from generating sources or transmission lines to substations. Con Edison owns or jointly owns 438 circuit miles of overhead lines operating at 138, 230, 345 and 500 kilovolts (kV), or thousands of volts. The Company’s overhead transmission system is comprised of 1,212 towers that support “open-wire” type conductors.

We operate the largest underground transmission system in the United States: 727 circuit miles of underground cable operating at 69, 138 and 345 kV. The Company’s underground transmission feeders are either oil or solid-dielectric insulated. Oil-insulated cables are typically installed in steel pipes, whereas solid dielectric cables are typically installed in fiberglass reinforced epoxy conduit banks housed in concrete.


**Substations**

The Company’s 101 substations consist of components that transform the voltages and direct power in a safe and reliable manner. Con Edison owns and operates 39 interconnected transmission substations that route power to 62 individual area substations that, in turn, provide power to electrically independent distribution areas that serve our customers.

The transmission substations receive power, typically at the 345kV and 138kV levels, from generators, long-distance transmission lines, and connections to neighboring utilities, and transform it to the 138kV and 69kV levels typically used at the area stations. The area substations, in-turn, transform the power to the 33kV, 27kV, and 13kV levels typically used for primary distribution (see figure 2-8).
Distribution

Con Edison’s distribution infrastructure consists of about 93,800 miles of underground cable, which is about 3.8 times the circumference of the Earth, and about 27,500 miles of overhead wire, which is about 11 times the distance from New York to Los Angeles.

The Company’s distribution system consists of 63\(^9\) second contingency secondary networks, which operate at low voltage (120/180V) and 23 non-network distribution load areas. We have the largest low voltage secondary network system in the world with about 260,000 underground structures, and 26,000 underground network transformers, see Figure 2-9.

\[^9\] There are 64 second contingency networks, but the new network for WTC, Freedom, has no secondary grid.
Figure 2-9. Combined Distribution Primary and Secondary System
Each of our secondary networks is electrically and geographically isolated from every other secondary network. The components of a typical underground secondary network are illustrated in Figure 2-10.

**Figure 2-10. Typical Underground Electric System**

Secondary network designs are common in high density urban areas. They have multiple primary distribution feeders, network transformers, and secondary (or low voltage) mains serving power to a single customer. Consequently, the loss of a single feeder, transformer, or secondary main, in a secondary network design does not typically cause an interruption of power and thus, the configuration meets high reliability requirements. The underground installation allows us to meet the space constraints of our urban service territory. There are 2.44 million customers supplied by our underground network system. This level of system redundancy is inherently more costly as the urban underground networks tend to be more expensive to construct and maintain than suburban and rural networks, which are typically based on radial network designs and overhead construction.

The Company’s 23 non-network distribution load areas deliver power to 887,284 customers via 27,453 miles of overhead wire and 49,769 transformers. These areas are serviced primarily by 4kV unit substation grid configurations and 13kV or 27kV autoloop configurations.
The feeders in the 4kV unit substation grid configuration, illustrated in Figure 2-11, connect to a series of distribution transformers that step down power to supply residential customers with a house (or low voltage) service of 120/208V or 120/240V. 4kV primary grid feeders are tied together, allowing for continued service in the event one of the feeders is out of service.

Figure 2-11. 4kV Unit Substation Grid Configuration
The autoloop design of our overhead system, illustrated in Figure 2-12, integrates the electric system’s outage detection and protection equipment with automated feeder tie switches. This configuration enables fault isolation and automated switching of feeders and, under fault conditions, ensures power delivery to the maximum number customers.

**Figure 2-12. Overhead Autoloop System Configuration**

**Design Specifications**

Much of the Company's electric transmission and distribution system has been designed to satisfy a second contingency, or an “N minus 2” (N-2) standard, which means that, at various stages of electric transmission and delivery, the system is designed to withstand an outage to any two parallel devices, while still reliably serving customers.

Twenty nine of the Company’s area substations serve high-density load areas, defined as where customer load is dense and high-rise buildings are concentrated, and as such, are designed to the N-2 standard, whereas all of the Company’s 64 underground distribution networks are designed to the N-2 standard as well.10

The balance of the Company’s distribution load areas is of an N-1 or first contingency design. In these load areas, which are chiefly overhead systems, additional reliability is designed into the autoloop or 4 kV unit substation grid configurations to limit the number of customers affected by any given outage.

Application of these design standards, with contingency built into the system, results in a more expensive distribution system. Customers have benefited from the investment because of the resultant reliability.

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10 N-2 design standard was applied to our distribution system for high density load areas prior to 1961 and mandated thereafter. See New York Commission Order dated July 19, 1961 concerning Con Edison.
2.3.3 The Customer Bill

The Con Edison customer bill reflects the Company’s tariff charges for electricity delivery, charges for electricity supply, taxes, and regulated fees. As the operator of the delivery system, Con Edison collects all components in a single customer payment and remits payments as required to the appropriate parties. Our delivery charges constitute about a third of the typical residential bill; the remaining two thirds are attributable to costs of supply and costs to cover taxes and fees imposed by various electricity suppliers and government agencies. Figure 2-13 illustrates the breakdown of charges for a typical New York City residential customer in 2011.

![Figure 2-13. Breakdown of Residential Bill in 2011](image)

**Delivery Rate**

The delivery rate represents the cost of transporting energy from the point of supply to the Con Edison system to the customer and constitutes 30% of an average customer bill. This rate covers costs to build and maintain our transmission, substation, and distribution assets as well as to maintain and operate the customer billing and other operations platforms to service customers.

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11 Based on 300 kWh, residential customer usage in New York City. Average usage in Westchester County is 450 kWh; however the breakdown of bill components is consistent. Supply rate varies with the market and is passed through to Con Edison customers.
Delivery cost is influenced by three factors: system reinforcement, new business connection, and maintenance. System reinforcement is the cost of infrastructure upgrades to support growing demand requirements of customers. Customer demand growth is the addition of new infrastructure and may require feeder upgrades, new transformers, or new substations. New business connection is the cost associated with serving new customers within our service territory. Maintenance costs include operations and maintenance costs for existing infrastructure, replacement of system components, installation of additional monitoring to reduce outages, and components required to achieve mandated environmental improvements.

**Delivery Tax and Fees**

The delivery taxes reflected in the customer bill are based on the total tax bill assessed to Con Edison. On average, delivery taxes represent 25% of the total customer bill, and 45% of the transmission and distribution portion of the bill.

The customer bill also includes fees collected for external entities. The System Benefits Charge and Renewable Portfolio Standard surcharge are mandated fees that finance energy efficiency and renewable portfolio programs owned and operated by the New York State Energy Research and Development Authority (NYSERDA). The System Benefits Charge funds programs that have been determined by the Public Service Commission “to be inadequately addressed by New York’s competitive energy markets.”[^12] Currently the charge is between 0.2 cents/kWh and 0.22 cents/kWh, which equates to roughly 60 cents per month for the typical residential customer.

The 18-a Assessment is an additional fee imposed by the New York State Legislature for the support of the State’s General Fund and is expected to represent 0.36 cents/kWh in 2011.

**Supply Rate and Supply Tax**

As illustrated in Figure 2-13, the supply rate constitutes 41% of an average residential bill. Since customers purchase their electricity supply from a range of competitive suppliers, the supply rate is largely outside of our purview. We have largely divested our generating plants and primarily purchase our customers’ energy requirement through contracts and purchases from the energy markets. Customers who purchase their electricity supply from Con Edison are characterized as full service customers and are charged Con Edison’s cost for their electricity. In 2008, 42% of the electricity delivered on Con Edison’s system was to full service customers. The balance of our customers’ electricity supply was provided by a variety of competitive suppliers, the New York Power Authority (NYPA), and various municipal electric agencies.

As much as practical, Con Edison’s electricity supply is developed from the least cost options available to the Company and is typically a composite of short- and long-term firm supply contracts, Con Edison production[^13], and spot market purchases made by the Company. Con Edison’s cost of electricity and the allocation of these costs in customer rates are subject to regulation and review by the New York State Public Service Commission.

Consequently, the supply portion of our customer bill is directly related to the market price of electricity, which is itself highly dependent on regional fuel supply costs, fuel mix, environmental costs, and regulatory conditions.

[^13]: Less than 5% of electricity delivered is generated by Con Edison.
and the supply/demand balance. Many of these core cost factors have been characterized by significant volatility in recent years. This volatility is expected to continue and potentially increase in the future as a result of rising and uncertain fuel cost, new technologies, and changing environmental regulation.

A supply tax, representing approximately 3.5% of an average residential customer’s bill, is imposed on each customer. The tax is based on a sales tax rate applied against purchased supply and a general receipts tax applied against Con Edison total revenues.

### 2.3.4 Performance, Cost, and Risk Trends

The Company will make business decisions related to operation, maintenance, and investment in the electric system in the context of their impact on the system’s performance, cost, and risk metrics. In this section we describe our historical performance on these dimensions and our goals for the future.

#### Performance

Con Edison’s customers have come to expect a high level of electric system reliability, and our goal is to consistently meet that expectation. By doing so, we have frequently been cited by industry groups for our high reliability performance. Con Edison, for example, has received the ReliabilityOne award from PA Consulting seven times since 2001.

Figure 2-14 compares customer interruptions per 1,000 customers per year for Con Edison to the national and New York State average. Con Edison experiences about 130 interruptions per 1,000 customers per year, which is significantly more reliable than the New York state average of 890 and the national average of 1,240. Under this metric, 1,000 interruptions per 1,000 customers represent one interruption per customer per year.
Figure 2-14. Customer Interruptions, 2010

Interruptions per 1,000 Customers per Year

- National (USA): 1240
- New York State (w/o Con Edison): 890
- Con Edison (Overhead): 415
- Con Edison (Network): 23
- Con Edison (Overall): 128
A second common measure of reliability is interruption duration. Figure 2-15 presents the Customer Average Interruption Duration Index, or the average outage duration experienced by those customers who experience an outage.

**Figure 2-15. Customer Average Interruption Duration Index (CAIDI), 2010**

![Duration of Average Customer Outage](image)

The Company's higher outage duration reflects the greater amount of time needed to identify and repair assets in our extensive and highly complex underground network system. In our underground system, many of the manholes and service boxes are not immediately accessible, which extends the time it takes to make repairs to service cables in the underground systems. Restoration time is significantly shorter for customers on our overhead system, which is more accessible. The Company places a high priority on minimizing overall outage times.

To continue high reliability performance, we set the following performance objectives for the Electric System Long Range Plan: to maintain system reliability at our current, industry-leading level and to improve our customer restoration performance, as measured by outage duration and feeder restoration time.

**Cost**

The Company's component of the overall “cost of service” is primarily for construction, operation, and maintenance costs for our transmission and distribution infrastructure and is a primary input into determining the Company’s electric rates.

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Asset Intensity

The N-2 design standard, while highly reliable, results in a higher level of distribution assets per customer, as compared to the industry. At the end of 2010, Con Edison had 71% more distribution plant per customer than the median for New York utilities\(^\text{15}\), due to both the rigorous N-2 design and the generally high cost of conducting business in the service territory. The Company’s transmission plant per customer, which is more in line with the industry average, was equal to the median for New York utilities\(^\text{16}\).

Operations and Maintenance Cost Patterns

The Company’s operations and maintenance costs are also a critical component of our cost of service. At the end of 2010, our distribution operations and maintenance cost per customer was 17% lower than median for New York utilities. This pattern largely reflects the Company’s commitment to cost management excellence. The Company’s transmission operations and maintenance cost per customer was only 17% higher than the New York median.\(^\text{17}\)

The Company’s administrative and general costs on a per customer basis have historically been low relative to industry average. Even with the inclusion of recent high increases in fees and taxes, the resulting Con Edison administrative and general cost per customer is only 5% above the New York median.\(^\text{18}\)

Average Customer Rates, Energy Usage, and Bill

Con Edison’s overall cost per kWh of service (18.73 cents) is higher than the New York State average (15.49 cents) due primarily to the rigorous design standards we employ, and the higher cost of doing business in our service area\(^\text{19}\). Nevertheless, Con Edison’s average yearly residential customer bill was right at the New York State median in 2010, as can be seen in the first chart below. This is a result of the relatively lower usage patterns that are characteristic to dense, urban environments, where residential customers predominantly live in multi-family units with correspondingly lower lighting and space conditioning requirements. As such, New York City has been applauded for being the most energy efficient city in the state. This is reflected in the second chart below.

\(^{17}\) FERC Form 1 data, 2010. www.dps.ny.gov. At the end of 2010 Con Edison distribution operations and maintenance cost per customer was on average $134 per customer versus $161 for the NY median. Transmission O&M costs per customer are in line with the New York median, reaching $52 per customer compared to $44 for the New York median.
\(^{18}\) FERC Form 1 data, 2010. www.dps.ny.gov. Con Edison administrative and general cost per customer was $312 versus the New York median of $298.
Our cost objectives are to minimize expenses through a combined strategy of encouraging effective energy efficiency, improved processes and operations, reduced asset intensity and regulatory and tax reform, offsetting projected cost increases without sacrificing reliability.

**Risk**

Given the complexity of and critical dependency on our electric system, there are numerous inherent operational, financial, and safety risks that could potentially impact our customers, the communities we serve, our employees, and the public. The Company evaluates its risks and seeks to mitigate them to improve its performance. As a result, these risks drive many O&M programs and capital investments, and are considered within the project prioritization process when planning the budget.

We have developed an enterprise risk management (ERM) process by which the Company identifies, monitors, and mitigates risks. Below we highlight our ERM process and, as examples of some of the risks we manage, we describe our ongoing efforts to mitigate risks associated with wide-scale system reliability and employee and public safety.

**Enterprise Risk Management**

The Company places a high priority on identifying and mitigating risk and, like many other companies, has implemented a formal ERM process. Con Edison’s ERM program, initiated in 2005, is the subject of ongoing refinement to improve its effectiveness. Through a collaborative process of risk assessment, ERM has become embedded into the planning and budgeting functions of all operating groups. As part of the annual ERM cycle, groups identify operational and administrative risks, and

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assess their severity, likelihood, and controllability. These assessments are reviewed and adjusted through the active participation of senior management.

ERM is a process to identify, analyze, integrate, evaluate, manage, monitor, and communicate risks across the Company. Our risk management program has three primary objectives:

- **Systematic risk mitigation**—Evaluate the severity, likelihood and control mechanisms of risks issues and provides for the proper risk mitigation strategies and response preparedness.

- **Proper allocation of resources**—Integrates ERM into the development and evaluation of business cases and annual budgeting and longer-term program development to evaluate adequacy of resources for risk mitigation.

- **Enhanced communication and transparency**—Provides for greater transparency and collaboration by actively involving all levels and functions of the organization, up to and including the CEO. Establishes accountability for each risk by assigning an oversight and responsible officers.

As shown in the Figure 2-17 and described below, ERM allows Con Edison to translate a broad concept such as “risk” into quantifiable measures of severity, likelihood, and controllability.

- **Severity**—Estimates the risk event’s potential impact on public perception, safety, finances.

- **Likelihood**—Estimates the likelihood that an event will occur based on past experience and current probability.

- **Controllability**—Estimates the likelihood that existing detection or control mechanisms would predict or prevent the event.

For each identified risk, these three components are assigned a value from 2 to 10. These component factors are then multiplied to produce a risk priority number. The risk priority number quantifies the relative priority of risks across the Company. This value is a key input to the Capital Optimization process described in Chapter 5 of the Electric System Long Range Plan.
## Figure 2-17. Risk Assessment Factors

**ERM - RISK ASSESSMENT FACTORS**

The following table should be used as a guide for assessing risk within the context of an enterprise risk management system. Consider the most probable realistic worst-case scenario.

### Severity Factor

Estimate the severity of the event using the five-point scale and use the highest score of the three perspectives:

<table>
<thead>
<tr>
<th>Factor</th>
<th>Public Perception Perspective</th>
<th>Safety Perspective</th>
<th>Financial Perspective (After taxes and insurance)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Insignificant</td>
<td>2 No effect</td>
<td>First Aid</td>
<td>up to $3M</td>
</tr>
<tr>
<td>Moderate</td>
<td>4 Minor impact</td>
<td>Medical</td>
<td>$3 to $15M</td>
</tr>
<tr>
<td>Significant</td>
<td>6 Marginal impact</td>
<td>Restricting</td>
<td>$15 to $50M</td>
</tr>
<tr>
<td>Severe</td>
<td>8 Significant public perception impact</td>
<td>Disabling</td>
<td>$50 to $250M</td>
</tr>
<tr>
<td>Catastrophic</td>
<td>10 Major public perception impact</td>
<td>Fatality</td>
<td>&gt;$250M</td>
</tr>
</tbody>
</table>

### Likelihood Factor

Estimate the frequency of occurrence of the triggering event based on past experience as well as considering the current probability of the event occurring:

<table>
<thead>
<tr>
<th>Factor</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rarely</td>
<td>2 One incident in 10 years</td>
</tr>
<tr>
<td>Unlikely</td>
<td>4 One incident in 5 years</td>
</tr>
<tr>
<td>Likely</td>
<td>6 One incident in 3 years</td>
</tr>
<tr>
<td>Frequent</td>
<td>8 One incident in 1 year</td>
</tr>
<tr>
<td>Certain</td>
<td>10 Greater than one incident per year</td>
</tr>
</tbody>
</table>

### Controllability Factor

Determine the likelihood that existing detection or control mechanisms would predict or prevent the triggering event:

<table>
<thead>
<tr>
<th>Factor</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Almost</td>
<td>2 Excellent detection and control over the triggering event</td>
</tr>
<tr>
<td>Certain</td>
<td>4 Highly predictable detection and control over the triggering event</td>
</tr>
<tr>
<td>High</td>
<td>6 Detection and control are reasonably achievable</td>
</tr>
<tr>
<td>Probability</td>
<td>8 Detection and control are very limited</td>
</tr>
<tr>
<td>Moderate</td>
<td>10 No ability to detect or control the triggering event</td>
</tr>
<tr>
<td>Low</td>
<td></td>
</tr>
<tr>
<td>Impossible</td>
<td></td>
</tr>
</tbody>
</table>
The output of the ERM process consists of detailed mitigation plans for each key risk. Illustrative examples of risks are set forth in Table 2-2.

Table 2-2. Illustrative Electric Distribution Operational Risks

<table>
<thead>
<tr>
<th>Event</th>
<th>Mitigation Programs</th>
</tr>
</thead>
</table>
| Distribution Low Voltage Equipment Failure | • Secondary main replacement  
 |                               | • Secondary rebuilds                                   |
|                               | • Vented manhole covers                                 |
|                               | • Annual stray voltage testing                          |
|                               | • Mobile stray voltage testing                          |
|                               | • Facility inspections                                  |
| Distribution Transformer Failure | • Transformer replacement                              |
|                               | • Remote monitoring system                              |
|                               | • Network transformer inspections                       |
|                               | • Transformer evaluation                               |
|                               | • Failure detection and loss of life estimate           |

Risk of a Large-scale, Prolonged Network Outage

The Company has established a network reliability index (NRI) to measure the risk to each Con Edison network. NRI measures the probability that the four or more feeders supplying power to one portion of a network experience simultaneous failure under standard conditions. NRI therefore indicates the likelihood of experiencing cascading feeder failures that potentially result in overload conditions on nearby feeders and, in extreme cases, a network shutdown.21

To improve our NRI performance and reduce the risk of a large-scale, prolonged network outage, we have made improvements in network feeder restoration, effectively reducing the feeder outage time from an average of 33 hours in 2004 to 13.5 hours in 2011. This performance improvement is not fully captured in average customer outage statistics (or CAIDI, the customer average interruption duration index) because most out-of-service feeders in the network system do not cause customer outages. However, this performance improvement lowers the risk of a large-scale, prolonged network outage and is therefore an important element of our risk mitigation efforts.

NRI is proving itself as a reliable and efficient planning tool; we believe it is a useful complement to our second contingency design criterion as a planning mechanism, helping to maintain overall reliability while reducing risk costs.

Public and Employee Safety

The Company operates several hundred thousand structures with energized equipment in the New York metropolitan area. We focus on the safety of the public in the surrounding areas, and on the safety of our employees who are working in and around these structures.

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21 NRI is calculated based on failure rates for cable sections, joints, transformers, and other equipment based on their age, temperature range, voltage, and loading conditions to model specific network performance under various scenarios.
The Company has made a commitment to improving public safety by implementing a rigorous stray voltage detection and correction program using the newest technology. Stray voltage in Con Edison’s service territory is primarily a result of insulation breakdown on the low voltage cables or from defective neutral connections in streetlights and overhead wires. Some stray voltage inadvertently energizes publicly accessible structures, although few are significant enough to cause bodily injury.

In 2005 Con Edison initiated an aggressive stray voltage detection and correction program. Our program uses 14 stray voltage detection vehicles to conduct comprehensive scans of the underground network electric system. When stray voltage is detected, repair crews respond promptly to remedy the cause. In cases where a crew is not available, site safety personnel arrive on scene to barricade the area until a repair crew is available. In 2010, the Company performed 12 mobile stray voltage scans of the Con Edison underground system in New York City and one mobile scan of its underground system in Westchester County.

There has been a decline in the number of Energized Equipment Incidents as illustrated in Figure 2-18.

**Figure 2-18. Energized Equipment Incidents**
The results of Con Edison’s stray voltage detection program are also apparent in our Electric Shock Report performance. An electric shock report occurs when an employee or member of the public reports detecting a “shock” from stray voltage in our service territory. Figure 2-19 highlights that the number of ESR incidents is also declining. This is due to the Company’s stray voltage detection programs that are identifying stray voltage incidents much sooner, at much lower voltage, and correcting conditions immediately.

**Figure 2-19. Electric Shock Trends**

The stray voltage initiatives have resulted in measurably improved public safety in this area. It is critical to economic efficiency to continue to evaluate programs and to focus scarce resources on the most effective programs. With that in mind, the Company believes that modifications can be made to the current stray voltage program that will maintain the progress achieved to date, freeing up resources to apply to other appropriate programs.

The reliability performance and risk characteristics of the Company’s 64 networks are also linked to the performance and failure patterns of the underground distribution transformers that supply power to them. In-service failure of these underground network transformers can be a public safety issue.
The Company has fully implemented remote monitoring systems on all network transformers as well as enhanced transformer monitoring, inspection, and maintenance programs. As can be seen in Figure 2-20, the failure of these network transformers has dropped 72% since 2005.

**Figure 2-20. Underground Network Transformer Failure Trends**

![Figure 2-20. In-Service Failures of Underground Network Transformers 2005-2010](image)

Employee safety is a top priority for Con Edison. We have a number of programs and guidelines in place to achieve an injury-free workplace. The main performance metric in the area of employee safety is the OSHA incidence rate. The incidence rate is a normalizing indicator that captures the number of recordable injuries/illnesses per standard unit of 100 full-time equivalent employees (each working 2,000 hours per year). It is dependent upon the number of recordable injuries/illnesses experienced and the number of productive hours worked, which includes all straight time, compensable overtime, training hours, and restricted duty hours for both weekly and management employees.

Con Edison's current safety performance, as measured by the incidence rate, is currently at the midpoint of its industry peers. The 2010 company-wide incidence rate was 2.48, or approximately 3 injuries and illnesses per 100 workers. We believe there is significant opportunity for improvement, and have therefore established its reduction as a key objective for all operating groups. Our current corporate goal is to reduce the OSHA rate to at least 1.50 (or 50% of the three year average OSHA rate from the years 2007-2009) by the end of 2014. Attainment of this rate would place Con Edison within the top quartile of utility industry OSHA performance. Our Environment Health & Safety group is working closely with all operating groups to make sure we achieve our safety goals, including providing appropriate tools and resources to ensure compliance with safety rules, performing

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22 The formula for calculating the incidence rate is: number of recordable incidences x 100 x 2000 / total number of productive hours worked.
comprehensive job planning and briefings, documenting site safety observations, and more broadly, promoting a culture of personal accountability.

Con Edison's goals in this plan relating to the risks facing the company are to:

- Continue to utilize our ERM process to systematically identify and prioritize emerging risks, develop risk mitigation strategies, and mobilize resources to execute those strategies.
- Improve the NRI by approximately 31% across the 15 worst performing networks by the 2015-2016 time-frame.
- Strive for continual improvement in employee and public safety by developing and executing innovative programs and processes.

In analyzing our historical performance on the dimensions of performance, cost, and risk we identified the following primary objectives.

- **Performance**—Maintain network reliability, while mitigating the risk of a large-scale, prolonged network outage. While these types of outages are infrequent events, their impact can cause significant hardship to our customers and can cause harm to property and public safety.23
- **Cost**—Improve the Company’s asset utilization while maintaining reliability.
- **Risk**—Continue to strive for improvements in all aspects of employee and public safety.

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23 Long Island City Proceedings. New York State Public Service Commission 06-E-0894
3.0 MANAGING DEMAND, SUPPLY, AND ENVIRONMENTAL PROFILE

3.1 OVERVIEW

Our Plan Case forecasts 16,425 MW of electric-peak demand in 2031, representing an approximately 25% increase over today. Along with the increase in demand for electricity, we expect there to be increases in the cost of the supply resources needed to meet that demand. Therefore, we continue to seek to integrate well-proven methods to manage both demand and supply to further our mission of delivering safe, reliable, and affordable service while minimizing our environmental impact. For example, demand side management (in the forms of demand response, energy efficiency, and distributed generation) may defer or eliminate the need for building additional infrastructure, while at the same time reducing greenhouse gases and enhancing reliability. Similarly, the well-planned integration of more renewable resources, electric vehicles, and storage devices in our service territory may improve the reliability of the system and reduce reliance on fossil fuel resources.

Our goals for managing demand, supply, and our environmental footprint are to:

- Reduce transmission and delivery infrastructure investments and power purchase costs
- Help customers manage energy costs
- Improve the environmental profile and do our part to meet Federal, New York State and New York City energy and environmental targets
- Enhance Reliability
- Diversify the supply portfolio

To meet these goals we will develop a full portfolio of programs and initiatives; however, we will deploy them selectively based on their benefit to customers. Our plan includes programs and initiatives to:

- Expand our role as an energy advisor to customers by aiding them in managing their energy expenditures through energy efficiency and demand response programs.
- Facilitate and integrate distributed generation to provide more choices for customers and increase the penetration of distributed renewable, such as rooftop photo-voltaics, through customer and utility owned applications with minimized constraints on the electric system.
- Support the expansion of infrastructure to facilitate plug-in electric vehicle (PEV) deployment (and other emerging end-use applications) and potential storage and vehicle-to-grid applications through a series of pilots, working with industry associations, manufacturers and customers.
- Potentially invest in a cost-effective deployment of an advanced metering infrastructure (AMI) for the implementation, measurement, and dispatch of the aforementioned demand- and supply-side resources as well as to enhance our asset management and monitoring and control objectives.
- Consider the incorporation of new and renewable supply resources into the grid by developing partnerships to investigate new technologies and building new transmission lines (where necessary for reliability or where they are the most cost-effective solution compared to
• Continue to deploy a portfolio of environmental sustainability initiatives to improve Con Edison’s environmental impact in all aspects of our business.

3.1.1 Supply Outlook

The major balance of this document summarizes how Con Edison will optimize our transmission and distribution investments to meet our performance, cost, and risk objectives. While we will continue to make every effort to keep our transmission and distribution rates down, it is important to convey that market and policy will impact our customers’ bills. In particular, the composition, availability, and affordability of electricity supply may experience dramatic change over the 20-year planning horizon. Even assuming that fees and taxes remain consistent with current estimates, we expect supply costs to rise slowly, but steadily through 2031.

While we do not own significant sources of power generation we do procure energy for our full service customers, whose energy consumption in 2010 represented approximately 41% of all of our delivered energy. Con Edison works diligently to achieve the lowest reasonable supply costs for these customers. We accomplish this first by making informed and strategic purchase decisions, selecting a cost effective mix of power plants, long-term contracts, and direct purchases from the energy market. Second, we use financial hedging products to mitigate the volatility of our spot energy purchases with the objective of shielding our customers from supply market volatility.

We have begun to take an even more proactive role in managing supply costs by leveraging energy efficiency and demand response programs to reduce electric demand, which in turn reduces supply purchases, particularly when the region is experiencing peak conditions and the cost of supply is at its highest. We are also facilitating the integration of distributed generation assets into the grid thus, allowing our customers to identify additional cost-effective means of meeting their energy requirements, and further diversifying our overall supply portfolio. Our future plans regarding these initiatives are discussed in detail later in this chapter.

While we will continue to actively manage the supply costs for our customers, we still foresee that supply costs will rise over the 20-year planning horizon. For the Plan Case, our analysis suggests that the cost of supply will grow on a real 2011 dollar basis from 9.0 cents per kWh in 2011 to 11.2 cents per kWh by 2031, representing an average annual growth rate of 1.2%. For Con Edison customers, the primary driver of the cost of electricity is the price of natural gas used to generate that electricity by facilities in and around the service territory. The market price for electricity is determined by a market that is administered by the New York Independent System Operator. The NYISO gathers information from power plants and other resources in and around the Con Edison service territory to help match customer electricity demand to the lowest cost supply. At any point in time, the market price for energy is set by the highest bid generation unit that needs to be run to meet demand. And for Con Edison customers, that is usually a natural gas-fired unit. Over the 20-year life of this plan, it will likely continue to be a gas-fired plant, as Con Edison’s expiring non-utility generation contracts will likely be replaced by power from the New York Independent System Operator market. With gas-fired plant technology, since labor costs are low and it has low emissions compared to other fossil sources, most of the cost of running a unit is based simply on the input price of the natural gas burned. As the system grew, generating or demand side management).

24 Con Edison does not know if tax rates will remain constant over the planning horizon. We have made this simplifying assumption for the purposes of the Electric System Long Range Plan.
Company studies a number of longer-term demand forecasts, gas-fired units may not be on the margin exactly the same amount of hours per year in each case. But in general, gas will set the market price most of the time. There are many gas-fired units in the market, and more are proposed for development over the 20 years of this plan.

Con Edison customers also pay the cost of maintaining adequate generation supply through the New York Independent System Operator administered Installed Capacity (ICAP) market. These capacity costs can vary considerably and can be a significant portion of the electric supply cost. However, the capacity market prices tend to vary inversely with market prices for power and may offset some of the cost increases associated with a rising natural gas scenario.

The continued operation of large central station power plants that produce electricity at relatively low prices in New York State is another key uncertainty. For example, the Indian Point facility in Westchester Country is a major source of supply of electricity for Westchester County and New York City. The current owner of the facility, Entergy, is facing a re-licensing challenge and the outlook for its continued operation is uncertain. If the Indian Point facility were unable to continue to operate, replacing it would be a major challenge. This plan assumes that the transmission system would be maintained to continue to provide safe and reliable service to customers in the Con Edison service territory and NY State. Therefore, we assume that if the Indian Point facility discontinued operations, there would be sufficient replacement supply to maintain the required resources to meet the reliability standards. The analysis for the cost impacts are a separate assessment and not considered specifically in the cases presented.

Legislation and regulation are also significant drivers of supply cost increases. Proposed legislation includes a national Renewable Portfolio Standard and CO₂ cap and trade program. The Regional Greenhouse Gas Initiative is already in place for our region. Combined, the Regional Greenhouse Gas Initiative and a Federal CO₂ program will increase the unit cost of electricity for customers by applying a cost to CO₂ emissions associated with our supply portfolio. Also a large driver of supply cost growth is the cost associated with the additional transmission required to deliver the energy produced by additional renewable generation – both land based and offshore – to our service area. Figure 3-1 illustrates how we expect our resource mix to shift over twenty years in the Plan Case to meet these various requirements.
3.1.2 Demand, Supply, and Environmental Objectives

Con Edison intends to provide customers an integrated offering of solutions for managing their environmental impact and their electric bills through both demand and supply side options. This service offering will include programs to shave and shift peak demand, programs that conserve energy, initiatives to improve access to renewable and affordable electric supply resources, as well as a comprehensive environmental sustainability plan relevant to all aspects of Con Edison operations. In the following sections of this chapter we discuss the goals of our collective programs and initiatives.
3.2 DEMAND SIDE MANAGEMENT OVERVIEW AND OBJECTIVES

Con Edison aims to develop and grow its Demand Side Management (DSM) resources as part of the Company’s long-term strategy of effectively managing its supply, demand, and environmental profile. These DSM initiatives include energy efficiency and demand response programs, as well as programs aimed at permanent peak reductions and load shaping. By engaging and working closely with customers, Con Edison is able to provide the tools and incentives needed to permanently lower energy consumption and reduce electricity demand during times of peak demand in our service territory. Managing these initiatives in a cost-effective manner allows the Company to defer or avoid capital investments as part of its planning process.

In addition to being an integral part of the Company’s long-term strategy, the effective development of DSM resources is a key component of New York State’s energy, environmental, and economic policies. New York State’s policy goals consider energy efficiency a “high priority resource” with extensive benefits including: enhancing system reliability, easing wholesale prices and T&D, reducing emissions, and stimulating economic development in the state. Con Edison is committed to the advancement of these policy goals, which stand to benefit our customers, the state, and all other stakeholders associated with our involvement.

Growing demand for electricity can be met by building generation and transmission and distribution (T&D) capacity or by leveraging demand side management resources, or by a combination of both strategies. Permanent energy efficiency, as well as conservation, reduces overall consumption of electricity by installing more efficient equipment, whereas demand response resources reduce demand for electricity at a point in time, usually in response to pricing signals or system peaks, for a fixed period of time. “Load shaping” occurs when customers actively manage their consumption on an on-going basis to reduce peaks permanently in their load profile thereby creating more efficient load shapes.

While we are committed to deploying demand side management initiatives in our service territory as an alternative to expensive infrastructure investments, we are cognizant of the changes they represent for our traditional business model. To that end, we advocate a legislative and regulatory environment that drives the cost-effectiveness and innovation to meet our community’s demand reduction targets. The Company believes that an open and competitive energy efficiency and demand response market is the most cost-effective way to meet New York City and Westchester County’s future needs, and we would encourage that the energy efficiency bill surcharges should be re-evaluated on an ongoing basis to ensure cost effectiveness.

25 Numbers and projections in this section based on estimates built off of the September 2011 load forecast
3.2.1 Reduce Transmission & Infrastructure Investments and Power Purchase Costs

Our transmission and delivery system is constructed to meet the highest demand for electricity at a given point in time, which occurs in the summer for Con Edison. If our customers reduce their collective usage at that peak, we can reduce our transmission and distribution investments.

Active demand and supply side management will position us to better manage customer demand through peak shaving, peak shifting, and reducing overall energy usage. Lowering peak demand and energy use should allow the Company to defer or avoid infrastructure investments as well as reduce capacity and power purchases that would have been needed to meet higher peak demand. Figure 3-2 illustrates how demand and supply side initiatives help achieve these objectives.

Figure 3-8. Con Edison Managing Peak Usage

Cost effective deployment of these demand resources may allow us to postpone or permanently reduce the need for additional supply, transmission and distribution infrastructure, particularly when demand and supply side management programs are targeted to capacity constrained load areas. In addition, reducing demand can result in lower capacity prices, lower peak period energy, or both.

3.2.2 Help Customers Manage Energy Costs

Energy efficiency programs provide customers the tools to better manage their energy consumption. These programs are designed to give Con Edison customers the power to reduce their energy usage and energy costs through rebates on the purchase of efficient equipment including air conditioning, ventilation equipment, motors, lighting, and variable speed drives, and financial assistance for technical studies and custom projections, free removal and proper disposal of inefficient refrigerators,
and financial incentives to reduce the cost of highly efficient industrial equipment,

Similarly, demand response helps Con Edison customers lower the supply portion of their electric bill by reducing peak demand charges. In addition demand response and peak shaving may be able to reduce capacity purchase costs if there is an impact on the system coincident peak.

By helping customers understand and more efficiently manage their energy consumption and associated load shape, Con Edison will empower customers to reduce their direct energy costs and have a positive impact on the system supply costs as a whole.

3.2.3 Improve Environmental Profile and Meet Federal, New York State, and New York City Targets

As responsible corporate citizens, we are interested in environmental sustainability and we have actionable plans to reduce the environmental impact of our transmission and distribution operations, help our customers reduce their energy consumption, and reduce the carbon footprint from our day-to-day business activities.

The Electric Power Research Institute projects that multiple electricity production and consumption technologies will be required to measurably reduce national CO₂ emissions. Figure 3-3 illustrates the total potential CO₂ reduction from existing and emerging technology solutions. To that end, we are deploying a multi-pronged set of programs and initiatives: from energy efficiency (which reduces emissions) to demand response (which smoothes the interconnection of intermittent renewables). Together these programs can help meet our environmental objectives.
Our plan was designed to allow us to contribute to the achievement of the policy targets set at the Federal and State levels, as well as to support stated initiatives at various levels of the government, to the extent that such reductions are not already being provided by competitive market forces. At this point, New York State regulation establishes a strict standard for energy reduction and greenhouse gas regulation; thus, our plan is designed to meet New York State targets.

Specifically, our energy efficiency portfolio is intended to meet our portion of New York State’s goal of 15% energy reduction of forecasted levels by 2015. (See figure 3-4. Below) and support PlaNYC objectives to achieve 2005 consumption levels in 2030.

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26 Electric Power Research Institute (Electric Power Research Institute). PRISM/MERGE Analyses 2009 Update. This is EPRI’s latest publicly released update to this series of analyses.
27 June 23rd 2008 EEPS order establishes baseline as energy sendout projects based on 2007 forecasts for 2015
The New York State Energy Plan also sets renewable portfolio standards and greenhouse gas reduction targets. New York State has set objectives that 30% of electricity needs be met by renewables by 2015 and that 1990 levels of greenhouse gases be reduced by 80% by 2050. The Public Service Commission has recently adopted the 30% renewables goal predicated on successful achievement on the ‘15 by 15’ energy efficiency goal.\textsuperscript{29}

Specific targets for utilities, including Con Edison, have been established as part of the New York State Department of Public Service (DPS) Energy Efficiency Portfolio Standards (EEPS) proceeding. The EEPS proceeding also assumes that a portion of goals will be met by improvements in codes and standards, reductions of losses and other efforts. We also support local initiatives including accelerating improvements to the electric grid, electrifying the city’s fleet of vehicles, and requiring the phase out of #6 and #4 oil.

While we discussed the role of energy efficiency in achieving carbon reduction targets, it is worth noting that demand response programs, while primarily impacting peak demand, have shown to have some ability to reduce carbon emissions, potentially reducing the run-time of certain generating units during system peaks resulting in reduced peaking-generator emissions. Dispatchable demand response may also be able to be used as a tool to allow the integration of intermittent renewables into the grid by smoothing consumption peaks. Thus, demand response may be critical to help New York state achieve its renewables goals.

\textsuperscript{28} New York State Energy Planning Board. “2009 State Energy Plan.” December 2009. Changes to utility and NYSERDA allocations are subject to change in the future.

\textsuperscript{29} New York State Public Service Commission Case-E-0188, Order Establishing New RPS Goals and Resolving Main Tier Issues (January 8, 2010)
3.2.4 Diversify the Supply Portfolio

Timely, dispatchable demand response may be critical in reducing the reliance on fossil fueled generation. This may be done by assisting in the integration of intermittent renewables into the grid and by smoothing consumption peaks through the integration of curtailment resources. Customers who are able to more efficiently shape their load (for example, through energy storage), may realize greater utilization of more efficient base load generation.

Integrated Demand Side Management

Details of the DSM programs currently offered are outlined below. Con Edison will analyze which programs can be most effective in meeting the energy management goals of the various customer segments. The Company will also evaluate if demand side management can offer a more cost effective solution than traditional infrastructure expansion for load relief needs of the system. Con Edison will continually monitor program costs and effectiveness and will only continue to pursue cost effective programs.

3.2.5 Energy Efficiency Plan

Con Edison will continue to work collaboratively with the New York State Energy Research and Development Authority (NYSERDA) on statewide efficiency objectives. Currently, NYSERDA is funded by rate payers through the System Benefits Charge (SBC), which was established on May 20, 1996, and was specified for funding from July 1, 1998 to June 30, 2001. The SBC was extended through June 30, 2006, and most recently until December 2015. These SBC funds are allocated towards: energy-efficiency programs, research and development initiatives, outreach and education programs, low-income energy programs, and environmental disclosure activities across New York State. Because of our direct relationship with our customers, we believe we are well positioned to directly partner with customers to reduce energy usage.

Con Edison’s service territory is comprised of areas with diverse communities made up of customer segments with distinct needs. Meeting the need of this physically small but densely populated, geographically diverse area requires a tailored portfolio of energy efficiency programs that allow all customer segments to manage their energy usage. We currently deliver 13 approved efficiency programs. We expect to modify these programs and potentially propose to discontinue or start new programs as market conditions warrant.

We believe that the EEPS programs have gained momentum. Looking ahead, we wish to build upon this momentum and improve EEPS Programs in a way that streamlines the customer experience and can increase savings cost effectively. To accomplish this, we support providing customers with holistic solutions that address demand management, improve power quality, and are supported by rate structures that encourage off peak use. This will present customers with the opportunity to address their energy and capacity needs in a fully integrated fashion.

Con Edison’s Targeted Demand Side Management (DSM) program is designed to defer Transmission and Distribution (T&D) expenditures by reducing peak demand in specific network and load areas of our electric system. As customer demand grows over time, the equipment to our various networks and areas begin to approach their design capability. Traditional planning solutions to possible equipment overloads have focused on the addition of generation and T&D infrastructure to relieve constraints. However, by directing peak demand reductions to these areas, the Company could defer
or avoid the need for capital expenditures associated with addressing this growth.

It should be noted that in the absence of the Targeted DSM program, the Company would have reacted to the recent forecasted demand growth by spending capital dollars on networks that had been expected to be constrained, but the constraints never materialized due to the economic downturn. This in turn, saved the Company and the ratepayer from funding unneeded expenses.

Since 2004, the Company has implemented its Targeted Demand Side Management (DSM) Program to provide demand reductions through energy efficient installations at customer facilities within designated areas. Con Edison currently has authorization and funding to continue its Targeted DSM program through 2015 in an amount not to exceed $25 MM/yr.

Candidates for deferral through the Targeted DSM program have included:

- Transmission lines
- Substations
- Network load transfers

In addition, the 2011 extension of the Targeted DSM program allows for additional focus on the deferral of distribution system equipment, such as transformers and feeders.

Because of their importance to system planning, achieved Targeted DSM load reductions are verified by an independent Measurement and Verification (M&V) program that uses an independent contractor.

Helping customers manage their demand and energy use is critical to system planning. Nevertheless, to maximize efficiency savings at a sustainable, responsible cost will require the ability to develop transparent and defined processes for new and re-designed programs to receive review and approval in an expedited manner.

### 3.2.6 Demand Response Plan

Con Edison has successfully implemented a number of contingency and system peak reduction demand response programs in its service territory. The Company plans to simplify its demand response and peak management offerings to make these opportunities more accessible to customers. As part of Con Edison’s targeted approach to system investments, some of these programs will be focused on the network and load areas that have the most critical capacity and reliability needs. The targeted deployment of verifiable and measurable demand response and peak management ensures the highest return on investment.

### 3.2.7 Portfolio of Demand Response Programs

Con Edison currently (as of November 2011) operates demand response and peak management programs, collectively called “DR”, designed to incentivize both residential and commercial customers to reduce their demand for energy in response to both contingency events and during times of peak system demand.

Building on the experience acquired through the implementation and operation of our current programs, we will continue to develop the next generation of DR tools designed to reduce network
peaks, system peaks, and peaking generator emissions and to help our customers better manage their energy use.

### 3.2.8 Price Signals

The Mandatory Hourly Pricing Program (MHP) requires customers with greater than 500 kW of peak monthly demand to pay the market price for energy on an hourly basis. Customers’ supply charges are based on the NYISO day-ahead hourly market prices. Analyses of the customers’ response to these price signals have demonstrated limited impact on their load-shape. These evaluations were based on customers with demand in excess of 1,000 kW. Customers with demands below 1,000 kW but above 500 kW were only exposed to the hourly market prices during the summer 2011. The Company is currently undertaking a further evaluation to determine whether this group of customers has responded to the price signals provided. It should be noted that, anecdotally, the demand charge (kW) has a more significant “price signal” impact on the customer’s bill and load shape than marginal differential on the energy price (kWh). Customers, to a significant extent, have seemed content to “avoid” the price signal by securing an ESCO contract through which they can pay a fixed rather than variable price and bring greater certainty to their operational planning.

The Company also offers a Voluntary Time of Use Pricing Program which allows customers with monthly demand less than 500 kW to choose a voluntary variable rate. This program is designed to encourage customers to reduce electricity use during peak hours.

### 3.2.9 Customer Enabling Technology

We believe that the best way to deploy DR in New York City and Westchester County is by coupling it with the right technology enablers. Integrating the right automation, monitoring, and verification infrastructure and processes will unleash the full value of DR for our customers. Starting the summer of 2012, commercial customers participating in the Company’s DR programs will receive real-time, 15-minute interval metered data feedback on their load reduction activities during demand response events. An effective and consistent communications infrastructure and a robust meter data management system (MDMS) are core components of efficient demand response programs; the success of which cannot be underestimated in the dense urban environment of New York City.

One of the greatest challenges for the Company in addressing its peak-demand is the wide use of window and wall air conditioning units. There are approximately six million such units representing nearly 2,500 MW of peak load. Forecasts suggest that this population will increase by one million over the next five years. At this time, there are very few control solutions for customers with these devices; thus creating a barrier to customer participation in DR programs. The Company is working with a partner on the development and deployment of a smart plug device with remote control capability, via PC or smart phone, to fill this technology gap. A successful proof of concept demonstration was conducted during summer 2011 and the Company is currently working on plans to bring this solution to market.
3.2.10 Implementation Plan

The implementation of Con Edison’s energy efficiency and DR plans will continuously evolve and improve over the next twenty years and can generally be described in three phases, as illustrated in Figure 3-5. During Phase I, Con Edison will expand program offerings, test new programs, and lay the groundwork for dispatchable, measurable, and verifiable demand resources. In Phase II we drive penetration of market-based pricing, automated dispatch, and integration of DR and energy efficiency with other demand and supply side resources. In Phase III we will continue to drive penetration in key segments, expand linkages with the smart grid technology (for example distribution automation) and focus on reducing the cost of acquiring demand side savings (whether permanent efficiency or peak reduction).

Figure 3-5. Energy Efficiency and Demand Response Implementation Plan

Phase I will involve refining and expanding Con Edison’s program portfolio. The Company will continue to coordinate with New York City and NYSERDA and other appropriate stakeholders on the development of programs. Con Edison will also identify the most load-constrained networks in our territory, and will expand the current targeted efforts to those networks. This will ensure programs continue to deliver the most valuable cost-benefit proposition, even as investments and demographic changes alter a network’s profile. A robust portfolio of programs will be launched, with the most successful programs then being aggressively expanded across the service territory.

Another potentially critical element of Phase I will be the investment in yet-untapped, targeted demand response resources and solutions for window/wall air-conditioning. These initiatives will facilitate mass-market, dispatchable and verifiable DR in our service territory.

In Phase II, Con Edison will continue to drive the penetration of demand side resources in segments that represent either high usage segments or have a high potential for reduced consumption with new practices or technologies. For example, we expect there to be significant opportunity to work with developers, governments, municipalities, and other agencies to influence the efficiency of new construction through building codes. There may also be specialized efficiency solutions for: financial services, building managers, hospitals, government, or education facilities. Programs will be tailored to drive maximum changes in consumption without compromising quality of service. In addition, we believe there will be increasing opportunities to tie programs focused on permanent conservation to other demand-side solutions, such as DR and distributed generation to drive optimal improvements.

Con Edison also plans to continue to increase integration of energy efficiency, demand response and load shaping with building automation and controls throughout its system. Automation will increase
the certainty and verifiability of demand reduction and general load shape improvement from energy efficiency resources.

Phase III will occur at a time during which current emerging technologies may become widespread in New York City and Westchester County. The Company will expand programs aimed at new end-use technologies, such as electric vehicles, and will leverage smart appliances, and customer-sited storage solutions to drive optimal end-use efficiency improvements.

Longer-term customer awareness and acceptance should evolve to the point where financial incentives for efficiency may no longer be needed as customers will move voluntarily to more active management of their energy use or are required to do so based on Federal, State and City mandates for building codes and appliance & equipment efficiency standards. We expect that incentive-based programs will be limited and enhanced, or in some cases, replaced by competitively provided energy efficiency services and continually improving building codes & appliance standards. We believe the role for the utility will still be significant in terms of working with developers, governments, manufacturers, and local stakeholders, as well as customers in developing effective codes & standards and a culture of active energy management. DR initiatives will be supplemental to load shape initiatives which will focus on permanent behavioral changes driven primarily by customer-side economics enhanced by new storage solutions.

3.2.11 Implications for Long Range Planning

Since the introduction of the Targeted Demand Side Management program in 2004, energy efficiency has been integrated into the Company's planning and forecasting process and is considered a viable alternative to traditional capacity investments. Permanent energy efficiency can be targeted to select areas through focused marketing and designing solutions specific to the customer segments within these areas (e.g. commercial lighting controls for areas with a high concentration of office buildings).

We currently include demand and energy savings from Con Edison administered energy efficiency programs in our long range planning efforts. Our forecasts also include estimates of what we expect other state agencies (such as NYSERDA) to achieve in energy and demand reductions in our service territory. Finally we also include a portion of DR available in our service territory in our plans.

In order to plan our system investments and power purchase needs, it is imperative that we have accurate estimates of what energy and demand savings will be realized in our service territory. The measurement and verification of energy efficiency program achievements in our service territory is a key aspect of this effort. Having accurate achievement information allows us to better predict how program savings will distribute in the future – an accuracy which is critical for the inclusion of energy efficiency in our planning process.

Because of the lack of verifiable operational history for DR resources, a significant level of discounting has been applied to hedge against potential resource risk. The forecasting model that has been developed is robust but will be tested by performance over time. As we gain experience and greater confidence in the reliability over time of these DR resources, we can reduce the discounting, and the model will allow for a reduction in the risk mitigating hedge for this forecasting resource.
3.2.12 Energy Efficiency Cost Benefit Analysis

This plan has been designed by leveraging Con Edison's experience with demand side management, continued dialogue with the PSC, as well as industry benchmarks from the Electric Power Research Institute (EPRI) and other organizations. As shown in Figures 3-6 and 3-7, energy efficiency programs in CECONY's territory are expected to deliver energy savings of 3,181 GWh through 2021 and 570 MW of peak demand. Savings in 2012 and 2013, based on existing programs, effectively represent 1.4% and 2.5% of energy sales respectively.

Expenses associated with these programs, an average of $84 million per year, are based on Public Service Commission guidelines for costs of achieving the Energy Efficiency Portfolio Standard targets through 2015 of 50 cents per kWh and after that are projected to be consistent. Based on current performance the cost is approximately 48 cents per kWh; between 2011 and 2031, the levelized cost of these resources is expected to be 5 cents per kWh. Energy efficiency, carried out effectively, is generally regarded as a highly efficient investment; this is due in large part to the fact that the savings from an investment in energy efficiency repeat throughout the life cycle, reducing marginal energy costs and other costs. For the individual consumer, energy efficiency can provide substantial savings to his or her energy bill.

The reduction in energy consumption and peak demand from our energy efficiency programs can potentially result in significant savings for the Company. A large portion of that savings is the ability to defer necessary T&D investments into the future. The Company identifies the areas within its service territory at which a new large investment, such as a new substation, will be required. As Con Edison is able to reduce load through EE and DR programs, it is able to defer large capital investments into the future, which translates into dollar savings for the Company and ratepayers.

Reducing system usage also has significant environmental benefits across our service territory, including a 15,903,449\textsuperscript{30} ton reduction of CO\textsubscript{2}e through 2030.

\textsuperscript{30} Based on PSC 6/23/08 Order. 1 MWh saved = .5 tons of CO2 emissions.
Figure 3-6. Total Projected Energy Sales with and without Energy Efficiency
3.2.13 Signposts

The Company has identified signposts that will trigger the review and adjustment of its Energy Efficiency program portfolio at any point during implementation. Con Edison may have to increase expenditures or expected energy and demand savings from its programs as a result of any of the following:

- **Demand growth**—Higher than expected demand growth could create more cost-effective opportunities to leverage energy efficiency resources to offset load growth.

- **Pending Federal legislation that is more aggressive than New York State targets**—Aggressive efficiency targets could require us to create additional programs resulting in incremental expenditures to meet policy goals.

- **Achieving lower than expected energy efficiency**—If Con Edison or other agencies do not meet efficiency targets in the Con Edison service territory or codes and standards do not evolve as expected, utility targets could be increased to compensate.
On the other hand, the Company may have to decrease expenditures or expected savings if any of the following occurs:

- **Achievable potential below national averages**—Today’s already low consumption of most residential city dwellers could limit achievable potential, prompting Con Edison to reduce our savings projections

- **Regulatory proceedings do not turn out as planned**—Disallowance of sufficient funding to achieve targeted savings levels may limit success of programs as outlined

- **Price of electricity drops**—Lower electricity prices may make efficiency measures less cost effective on a relative basis

For Demand Response, the plan is based on today’s technologies, current load growth assumptions, and today’s regulatory and legislative environment. The Company has identified signposts that will trigger the review and adjustment of its program portfolio at any point during implementation. More specifically, we will monitor changes in technology innovations, load growth, and legislation, and will change our plan accordingly.

- **Higher than expected load growth**—Greater load growth than projected in the plan case could create additional opportunities to leverage demand response to offset load in targeted areas.

- **Emergence of new technology**—Technological applications such as “smart” appliances and other end-use devices could become more widespread improving the cost effectiveness of verifiable and measurable demand response.

- **Rate of penetration of supply-side distributed resources**—Faster than expected adoption of distributed generation may increase customer adoption of demand response programs (customer has the ability to shift to back-up generation when called on to curtail), or on the other hand displace some of the demand-side potential (if distributed generation successfully lowers the peak in constrained networks).

- **Legislative restrictions**—Continued restrictions around mandatory time-based pricing in the residential and small commercial segments may limit potential of overall demand response portfolio.

Throughout the phases of implementation, Con Edison will monitor these conditions, and will adjust programs as necessary.

### 3.3 DISTRIBUTED GENERATION

Distributed generation (DG) resources consist of a range of small-scale and modular devices (up to 20 MW) located at the customer’s premises as opposed to at a centralized station. DG is designed to serve some or all of the electricity needs of a customer using either fossil fuels, such as natural gas, or renewable fuel sources, such as solar or wind. A common, often fossil-fueled form of DG offers the customer the extra benefit of using the heat byproduct of electricity generation for facility heating and/or cooling. This is known as combined heat and power (CHP) and makes up a majority of the grid-connected DG in the Con Edison service territory.
Customers can choose to use their DG for emergency backup only, to offset thermal energy requirements, for peak shaving, for total energy offset, to produce surplus energy to sell back to the grid—or for some combination of these applications. In most cases, customers do not choose DG to allow them to disconnect fully from the grid; they choose it to offset or supplement some of the energy currently purchased or to provide emergency back-up power while still operating with grid electric service available on a standby basis.

DG has already been incorporated as a tool in system planning and forecasting in certain load areas under specific conditions, but as Con Edison expands the number of applications in which the Company is able to incorporate DG into its load-management portfolio, there are several factors we will continue to address to maximize this potential benefit to all customers:

- **Supporting infrastructure investments may be required**—To capture additional value from DG, resources must be monitored at a minimum and preferably be made dispatchable and verifiable, which may require underlying equipment enhancements, such as advanced metering infrastructure (AMI) or other appropriate technologies, and distribution system protection to support two-way power flow as well as communication between the DG resource and the utility control center.

- **Clear environmental regulations need to be adopted for fossil-fuel-based DG**—The health and environmental impacts of DG facilities in urban areas should continue to be reviewed so that appropriate air emission regulations can be adopted and enforced. Regulatory uncertainty exposes DG customers to the risk of unanticipated costs in the future and makes customer-sited resources less certain in system planning.

- **Safety and reliability protocols must be addressed**—To ensure the safe operation of DG, building codes are being reviewed to protect all stakeholders including: the Company’s employees, employees of other agencies (such as the Fire Department of New York), and the public at large. Con Edison is actively working with stakeholders on electric, gas and steam interconnections to clarify and streamline standards for DG so that they are more easily understood.

- **New arrangements with customers**—In the future, arrangements with customers in which the Company is counted on to provide less electrical back-up may be explored. This would require that DG customers be willing and able to give up full standby service or make themselves interruptible and would reduce the need for a Company back-up plan to make up the load-reduction provided by the DG operation.

### 3.3.1 Objectives

Table 3-1 highlights how DG helps achieve our demand, supply, and environmental impact objectives.

**Table 3-1. Role of DG in Achieving Company Objectives**

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of DG in Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce T&amp;D Infrastructure Investments and Power Purchase Costs</td>
<td>Specific large-scale CHP installations have successfully been included in the Company's load-relief plan and will be counted as additional substation capacity. This will allow us to defer future load relief projects by reducing the electric peak demand in these load areas, thus reducing the need for reinforcement of sub-transmission and substation equipment.</td>
</tr>
</tbody>
</table>
We are able to take advantage of this extra capacity even though Con Edison provides standby energy to DG customers in cases where we have historical data and near-real-time telemetry that ensures generator reliability and consistent output over peak periods. Company contingency plans will be put in place to make up for the counted-on capability should the generator be offline on peak days. In the future, customers willing and able to give up partial standby service or that are willing to make themselves interruptible could be given a monetary incentive and counted on with a reduced need for a Company back-up plan as we would not be obligated to serve their full load.

Solar PV and other small-scale DG are passively reflected in the load forecast. This effect may accumulate in certain networks and reduce infrastructure investment needs.

### Help Customers Manage Energy Costs
Some customers will find on-site DG more cost effective than purchasing grid-electric for their full load, particularly when financial incentives are available or (in the case of CHP) when they have consistent on-site thermal loads.

As customers adopt DG and reduce line losses and supply needs while also deferring some transmission and delivery investments, they may create a cost savings that will be passed on to all customers. However, this must be balanced against the reduced revenue collection from DG customers, which will increase the collection requirement from non-DG customers.

### Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets
Utility promotion of renewable DG such as PV, biogas, and perhaps building-mounted wind can potentially play a significant role in helping New York State to achieve its Renewable Portfolio Standards goals. In addition, the reduction in line losses provides an opportunity to reduce the greenhouse gas impact of electric delivery.

### Enhance Reliability
The proper integration of DG into the secondary network could result in increased reliability by reducing loading of certain system components.

### Diversify Supply Portfolio
Increased incorporation of DG will help to introduce diverse technologies and fuel sources while also reducing financial risk through small, geographically dispersed projects. As more customers adopt DG, Con Edison continues to enhance the network with sophisticated technologies, allowing customers to produce more energy than they need—energy that can be supplied to the grid and dispatched by Con Edison to offset other generation needs.

#### 3.3.2 Implementation Plan

Con Edison’s strategic response to DG consists of three phases, as illustrated below. In the first, and current phase, Con Edison will continue partnering with customers and other stakeholders, including NYSERDA, the DOB, FDNYC, and advocates of DG to facilitate interconnection of DG and examine the opportunity to pilot new projects and concepts for communications, monitoring, control systems, relay protection, fault-current mitigation. Some recent successes in this area include our release of a DG handbook for customers installing natural gas–supplied DG systems and the launch of the “100 Days of Solar” program that has helped our customers move quickly through the complexities of the PV approval process, streamlined permitting, and created valuable resources for customers interested in DG. We have also created an online “project center” that illustrates necessary agency and Con Edison requirements and allows customers to submit and track applications. Additionally, we have
chaired a DG collaborative with the Building Owners and Managers Association and the Pace Energy and Climate Center to address DG-stakeholder issues and have continued to expand the role of the DG Ombudsperson who is available as a resource to the public but also coordinates the centralization of DG information and the organization of an overall DG strategy. Additionally, we continue to take measures to mitigate the fault current impacts of DG through upgrades of substation equipment while advanced customer-sited controllers and technologies are mitigating fault current on the customer side.

**Figure 3-8. Implementation Plan: DG**

<table>
<thead>
<tr>
<th>Phase I: 1-5 Years</th>
<th>Phase II: 5-10 Years</th>
<th>Phase III: 10-20 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interconnection and concept piloting</td>
<td>Drive penetration in target load areas and/or segments</td>
<td>Implement transformational opportunities through policy and infrastructure enablers</td>
</tr>
</tbody>
</table>

Given these steps and the key development that we are now incorporating DG capacity into our load-relief plan in a way that actively manages costs and will contribute to future reductions in capital spending on traditional T&D, we believe we are well on our way to progressing into Phase II.

In Phase II we will bring the results of all of our phase I findings together, identify any gaps, and set an implementation strategy. Ideally, we will be in a position to promote adoption of DG in areas or networks targeted due to load relief or environmental needs. These target areas may be locations that have a high peak demand relative to their network capacity and where DG is a cost-effective method for offsetting load growth of these specific networks and network segments. This may require the provision of incentives or supportive rate structures, and if that is the case a structure for possible incentives will be evaluated, though this opportunity and how it would fit within existing programs is currently being explored by internal workgroups. We are also looking into the opportunity to create arrangements and adopt technologies that allow us to dispatch and manage load flow coming from third-party DG locations to reduce electric-network peaks and energy purchase costs.

On entering Phase III, likely between 2020 and 2030, Con Edison will focus on more transformational opportunities through new policy and infrastructure enablers. By this time, technology standards should emerge from the multitude of technologies being tested today. These standards should allow for simplified interconnection and management of disparate devices in the network as well as at utility and customer-sited DG locations, two-way communications between the DG resource and the utility control room, and appropriate incentives or tariff structures to support interoperability. DG reliability may be considered high enough that customers with generation may only require an N-1 type electrical connection. It may also become more feasible for customers in close proximity to link their DG units together to form a microgrid—a structure in which individual DG assets with excess capacity can serve as emergency back-up generation for other customers’ assets while sharing thermal and electric production. Theoretically, if sized to meet these customers’ peak summer demands, microgrids could become a dispatchable load, or under emergency conditions disconnect completely from the Con Edison grid. Con Edison is currently investigating how to derive the most system benefit from distributed energy resources, including microgrids, and we are participating in several pilot projects.
and studies towards this end. These include our DOE funded Smart Grid initiatives and pilots carried out by our 3G Systems of the Future team. This research will help us better understand the customer & Company benefits of microgrids & distributed energy resources and help us to set future interconnection standards that do not degrade network reliability or safety.

Table 3-2. Con Edison Programs to Study DG

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DG Interconnection(^{31})</td>
<td>Part of Con Edison’s application for funding under the American Recovery and Reinvestment Act (ARRA) is to install two-way communication to DG units and network protectors to facilitate expanded operations.</td>
</tr>
<tr>
<td>Smart Grid Interoperability Grant Program</td>
<td>The goal of the Interoperability of Demand Response Resources Demonstration in New York Project is to demonstrate methodologies to enhance the ability of demand response resources to integrate more effectively with the distribution network. A critical element of enhanced interoperability is the development and demonstration of the ability to interconnect DG with the Con Edison distribution network. This project will develop enhanced interoperability techniques, including the development of protocols and software to improve the coordination of numerous demand response resources to temporarily reduce demand. As part of the project, Innovative Power will design, construct, and operate two Demand Response Command Centers (DRCC) capable of directly controlling aggregated resources (including customer generation). Control of customer resources from the DRCC and Con Edison's distribution control center will allow for demand response resources to rapidly respond to support the distribution network during system contingencies.</td>
</tr>
<tr>
<td>Substation Breaker Upgrade</td>
<td>Program to upgrade substation equipment to accommodate DG.</td>
</tr>
<tr>
<td>Network DG Penetration Load Flow Electro-Magnetic Transient Program</td>
<td>Analyzes the impact of varying types and levels of DG penetration.</td>
</tr>
</tbody>
</table>

In addition to these programs, Con Edison is also piloting technologies which can be used to support DG (described in Table 3-3). The Company feels it is important to develop a strong perspective on how to best use distributed resources. Based on the results of interconnection and load flow studies as well as experience with these pilots, we will better understand the benefits, costs, and risks associated with DG.

\(^{31}\) CECONY has received a total of $181M from the American Recovery and Reinvestment Act (ARRA) for programs aimed to deploy a wide-range of grid-related technologies, including automation, monitoring and two-way communications, to make the electric grid function more efficiently and enable the integration of renewable resources and energy efficient technologies.
Table 3-3. Con Edison DG Pilot Programs

<table>
<thead>
<tr>
<th>Program</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Island City Smart Grid Pilot</td>
<td>Tests automated control technologies for solar resources, battery storage to manage the intermittent</td>
</tr>
<tr>
<td></td>
<td>nature of solar as a fuel source, and new interconnection concepts.</td>
</tr>
<tr>
<td>Grid Support Pilot</td>
<td>Deploys smart communication technologies between DG sites, regional controls rooms, and distribution</td>
</tr>
<tr>
<td></td>
<td>transformer network protectors (NWP) to coordinate the DG output with NWP load flows in order to avoid</td>
</tr>
<tr>
<td></td>
<td>excess strain on the network.</td>
</tr>
</tbody>
</table>

3.3.3 Forecast

Recent and Historical Adoption

The adoption of DG is nothing new to Con Edison or its customers. Over the last twenty years, periods of increased DG adoption occurred from 1989 to 1994 and from 2004 to the present. In the first period, 1989 to 1994, the technology of choice was reciprocating engines, which use a piston to produce energy and include the commonly known internal combustion engine (ICE) and steam engines, and provided, for the most part, diesel-fired emergency backup generation. The second wave of DG adoption, from 2004 to present has seen more MWs from adoption than in any previous period.

Over the last five years there have been more than 615 DG installations in Con Edison’s service territory. On the renewable side there has been a significant increase in the number of solar PV installations in our service territory. While the MWs of solar PV is still comparatively small, with individual systems ranging from an average of 6 kW for residential installations to 60 kW for commercial installations, the trend has generally been toward larger installations. This recent growth is driven by lower costs and available incentives (including expanded net metering legislation), a growing familiarity with the technology by the utility, customers, and permitting agencies, and by federal, state, and city energy policies and incentives. On the non-renewables side customer adoption has increased rapidly with several large (>3MW) gas turbine (GT) and internal combustion engine (ICE) natural-gas fired CHP installations and increased in smaller (65-400kW) installations at nursing homes, hotels, markets, and large residential complexes.
Table 3-4. Current Grid-connected DG Capacity by Generator Size as of November 2011

<table>
<thead>
<tr>
<th>Size</th>
<th>Aggregate MW</th>
<th>Number of Customers</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP &gt; 1MW</td>
<td>131 MW</td>
<td>122 customers</td>
</tr>
<tr>
<td>CHP &lt;1 MW</td>
<td>11 MW</td>
<td>62 customers</td>
</tr>
<tr>
<td>Solar PV</td>
<td>10 MW</td>
<td>600 customers</td>
</tr>
</tbody>
</table>

CHP continues to be the primary growth driver of DG in Con Edison territory and since 2009 90 MW of new CHP has come online (45 MW of which was at a single installation). This growth has been driven by low and stable natural gas prices, NYSERDA and property-tax incentives, and increased economic activity following the 2008 recession.

**Projected Adoption**

The best existing estimate for the technical potential for DG in the Con Edison service territory is 3,300 MW, from a 2002 study conducted for NYSERDA. The study began with a database of commercial, institutional, and industrial sites and applied a series of screens to leave only facilities with high load factors and high thermal utilization—both qualities that make for good CHP candidates. Of course the actual market potential will be lower than 3,300 MW and will vary based on customer economics and risk-tolerance, site restrictions, and policy. Many customers do not have the extra space required for a generating unit and purchasing additional space is often not feasible. Customers must also meet DEP/DEC standards on emissions and obtain all relevant permits to ensure generation assets are safe and will not inhibit the actions of other agencies, such as the fire department.

Successful installation of DG also requires addressing known problems of power quality and interconnectivity issues, which can cause varying output and system issues. Though Con Edison has already identified and put into place many solutions to these hurdles, each installation presents its own unique set of issues.

As can be seen from the historic growth of DG, adoption rates have increased in recent years, and there are signs of further acceleration. From 2012 through 2016 an additional 75 MW of large-scale CHP is expected to come online, based on Company discussions with interested customers. Based on these expected projects, historic adoption rates, market trends, and the stable spark spread we predict

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that CHP will make up the majority (200 MW) of 320MW of new grid-connected DG by 2030. Solar PV, based on market experience and anticipated NYSERDA funding levels, is expected to make up a small but increasing amount of this new generation—totaling 120MW by 2030.

![Figure 3-9. Projected DG Adoption](image)

The New York City government has expressed interest in clean DG in the city’s PlaNYC initiative, and New York State recognizes the benefits of clean DG in the New York State Energy Plan. PlaNYC projects that clean DG will make up 10% of the greenhouse-gas reductions necessary to meet the mayor’s 30x17 goal, which aims to reduce greenhouse gas emissions by City Government facilities by 30% by 2017. PlaNYC sets a wider target of 800 MW of clean DG by 2030, which our base-case projection falls short of.

However, our high case for adoption achieves a level by 2030 much closer to the PlaNYC goal. This case is modified for increased adoption rates of large-scale CHP and renewable as well as 2 key accelerators:

- Technology improvements and innovative financing that increase fuel-cell and micro-turbine adoption: +2 MW/year
- Oil-to-CHP conversion for customers changing off of fuel: +5 MW/year through 2020

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33This is the latest study completed.
Following recent regulation, as of January 1, 2030, all boilers must meet the equivalent emissions of burning low-sulfur #2 fuel oil, and by 2015 all customers burning #6 fuel oil must switch to #4 or better. Our accelerated case reflects moderate adoption of CHP by customers with close proximity to Con Edison gas mains. The Company is working to ensure CHP is considered by customers in situations where reduced electric load will defer capital investment.

3.3.4 Signposts

The current strategy and projections related to DG do not exist in isolation and are subject to external factors that will trigger review and re-adjustment, should that become necessary. These signposts will not affect the Company’s willingness to assist its customers in the interconnection of DG but may affect the strategic direction the Company desires to pursue and the extent to which it wishes to rely on DG as a planning resource, such as in the deferral of capital projects. These signposts include:

- **Economic recovery**— As we are recover from the 2008 recession, low capital availability continues to suppress the appetite for capital intensive projects in the commercial and industrial markets and bring down the overall appetite for risk. First-cut analysis seeks very low paybacks and treats CHP as a non-essential “energy” project that must compete with energy efficiency and other measures. There is evidence that as the economy recovers, companies will have more cash on hand for large projects.

- **New environmental regulation for local supply resources**— More stringent regulation of NOx, carbon dioxide, or particulates from customer-sited generation could drastically change the economics of certain DG technologies—particularly CHP powered by fossil fuels—and thus, alter adoption patterns and capacity projections.

- **Enactment of Federal renewable portfolio standards and greenhouse gas legislation**—If Federal guidelines become stricter than New York State’s goals, there may be an increased focus on the adoption of renewable DG in order to reach policy and any other goals.

- **Price of natural gas**—The price of natural gas is a strong indicator of market robustness. Indications are that the price of natural gas will remain low and stable, making CHP appealing over the long term, but this is not guaranteed.

- **Advancement in DG and storage technologies**—Improved cost profiles of DG technologies will increase the economic viability and, therefore, the adoption of DG. There is potential for disruptive technologies, such as energy storage, flywheels, and fuel cells, to develop much more rapidly than anticipated.

- **Further net metering legislation**— Favorable economic incentives for selling power back to the grid may drive DG adoption. Con Edison supports the use of transparent subsidies where subsidies are appropriate to encourage specific technology, or paying DG customer-generators with the true avoided cost of energy particularly once “grid parity” has been realized. Net metering was recently expanded to fuel cells up to 1.5 MW, the first time net metering has been allowed for a non-renewable technology with a relatively small footprint; the effect of this remains to be seen.

- **Innovative financing methods**—A trend towards new financing methods on the part of technology and DG providers, such as Energy Service Agreements (ESAs), Power Purchase Agreements (PPAs), and solar leases may increase customer adoption of DG technologies by reducing the upfront costs to customers and potentially ensuring grid-competitive rates.
Legislative shifts or future incentives—Legislation could drastically alter the DG landscape. This could come in the form of adjustments to standby rates or legislation that seeks to promote a certain technology. An example of the latter is Assembly Bill 5713-C, which is currently pending in the State Senate and Assembly. This bill would create a market for solar renewable energy credits in New York. While Con Ed supports the overall objectives of increasing solar investment, this bill would increase energy commodity costs for customers across the state by up to $22 billion and guarantee New York a high cost of energy far into the future. Such legislation could dramatically alter the expected balance between CHP and renewables.

3.4 ELECTRIC VEHICLES

Throughout history the U.S. economy has been driven by technological advancements. The Green Tech movement, including the electrification of transportation, has the potential to be a driving force in the years to come. Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) are widely accepted as providing lower operating costs, lower emissions and reduced dependence on imported oil.

The United States Government, as part of its initiative to address climate change, has pledged to invest billions of dollars in cleaner and more efficient alternative-fuel vehicles. Further, the State of New York, in its 2009 Energy Plan, expressed the goal of supporting energy and transportation systems to reduce greenhouse gas emissions. And, PlaNYC published the City’s objective of increasing the electrification of fleet vehicles.

Plug-in electric vehicles (PEVs) could have a sizable impact on electric utilities and the demand for power. Nearly every major auto manufacturer is preparing a PEV for introduction to the consumer market. With increased collaboration among auto manufacturers, utilities, government and businesses, PEVs appear to be a promising solution to the environmental consequences of dependence on vehicles with internal combustion engines. As more research and development is completed, designs will likely become more effective, energy efficient, and inexpensive. Plug-in hybrid electric vehicles will likely serve as a technology bridge to fully electric vehicles and a largely electrified transportation sector. Currently, dedicated electric vehicles are viable for niche applications, such as limited commercial delivery. If battery technology evolves and production increases, electric vehicles will likely become useful in other transportation applications.

While the future of electric vehicles is uncertain, Con Ed, the New York State Energy Research and Development Authority and the Electric Power Research Institute examined the potential effect of these vehicles on the electric grid (Transportation Electrification in New York State: Understanding Grid Impacts of Plug-in-Electric Vehicles. EPRI, Palo Alto, CA, NYSERDA, ConEd: 2011). PEVs have the potential to improve our asset utilization but we need to keep a close watch on how usage patterns and market deployment evolve as unexpected concentrated load draws could tax local transformers if a sizeable portion of PEV’s plug in at local peaks.

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34 Plug-in hybrid electric vehicles and battery electric vehicles (which do not have internal combustion engines) are both generally referred to as plug-in electric vehicles (PEVs).
### 3.4.1 Objectives

Table 3-5 summarizes how the carefully planned integration of PEVs into the grid will help us achieve our objectives for proactively managing demand, supply, and environmental emissions impact.

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Electric Vehicles in Achieving Objectives</th>
</tr>
</thead>
</table>
| Reduce Transmission & Distribution Infrastructure Investments and Power Purchase Costs | • Circuit level planning and measured integration of PEV load into the grid will be important so as not to overload individual circuits.  
• Potential to tap into PEVs as a storage option via vehicle-to-grid applications to offset demand growth and/or offset expensive peak-time power purchases. Use of this stored energy toward reserve margins may reduce transmission and delivery investments. |
| Help Customers Manage Energy Costs | • Facilitation of PEVs will lower customers’ overall energy expenses by offsetting gasoline with lower cost electricity. Studies have shown that because of the lower cost of fuels consumed to produce electricity as compared to the cost of petroleum, consumers and businesses that use PEVs can reduce the total cost of fuel for their vehicles.  
• Attractive time-based rates will be developed to encourage off-peak charging, limiting the increase in electric bills from PEVs. In addition, the potential of vehicle-to-grid power would allow owners to sell electricity back to the grid when their PEVs are plugged in at home. |
| Improve Environmental Profile and Meet Federal, New York State, and New York City Energy and Environmental Targets | • Preparing the grid for PEVs helps meet Federal, state, and city objectives to increase the penetration of alternative fuel vehicles.  
• An Electric Power Research Institute assessment suggests that PEVs can reduce greenhouse gas emissions from vehicles by approximately 200 million metric tons by 2030, which is equivalent to 40 million passenger cars. 35 |
| Enhance Reliability | • Proactively forecasting for PEVs down to the distribution circuit level will avoid any negative impacts on reliability caused by unforeseen load spikes from PEV adoption. |
| Diversify Supply Portfolio | • Potential vehicle-to-grid applications, through the creation of new storage applications, can help diversify the supply portfolio and reduce financial risks and volatility from reliance on large-scale centralized resources. |

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3.4.2 Emerging Plan

While there is still a lot of uncertainty about the viability of PEVs, Con Edison is active in shaping the landscape in our service territory by helping influence standards and conducting pilots to understand the impact on our customers and our infrastructure.

We have been active in the American National Standards Institute effort to publish an EV Roadmap aimed at the development of a relevant standards compendium and gap analysis. The alignment of the appropriate standards organization to the identified gaps will pave the way for the orderly and sustainable adoption of PEVs.

The company has been active in rolling out electric vehicles and assessing their impact on the electric infrastructure. While the vehicle manufacturers have put a lot of thought and research into the vehicles themselves, it has been left to the utilities to address the customer billing interfaces and interaction with the electric system. In testing these vehicles, Con Edison’s engineers found creative solutions to address these concerns.

For example, one problem that arose is how to track the charging of the electric vehicle. Unlike a traditional utility account which is located at a fixed address, a vehicle moves and may be charged in many places. A recently issued patent (US 7,917,251) to Con Edison covers a mobile metering platform that allows the vehicle to be charged anywhere with the cost of electricity being directed back to the users utility account. The mobile platform uses multiple wireless technologies that allow the meter to communicate even as the vehicle moves between wireless service areas. This provides a number of advantages to the customer since they may track the electrical power used for the vehicle and potentially enable the customer to receive incentives or future carbon emission credits. Other aspects of the technology allow for a system similar to EZPass that has a pre-paid account that the customer may use when charging away from home.

Other patents (US 7,693,609 and US 7,792,613) issued to Con Edison solve problems associated with the impact of electric vehicles onto the electric grid. These technologies provide for communication between the vehicle charger and the electric utility. The system allows for the controlling of the vehicle charge based on the loads being placed on the local electrical grid to avoid overloading the electrical equipment. By minimizing the impact of electric vehicles, costly equipment replacement may in some cases be avoided and system reliability improved.

We are also actively engaged in a number of PEV related initiatives as described below:

- **Utility and original equipment manufacturer PEV stakeholder group**—Con Edison was instrumental in helping develop a utility/original equipment manufacturer PEV stakeholder group with the mission of discussing prevalent issues related to PEVs. The group consists of utilities, auto manufacturers, and PEV component suppliers (battery and controls manufacturers).

- **Ford Escape plug-in hybrid electric vehicle testing and demonstration**—Con Edison, along with Southern California Edison and the Electric Power Research Institute, participated in a program to build, test, and demonstrate a fleet of Ford-engineered plug-in hybrid electric vehicles while conducting a set of detailed and comprehensive studies that will help define how to successfully commercialize the vehicles.
Electric Power Research Institute/ EV Infrastructure Working Group—The Electric Power Research Institute, OEMs, Con Edison, and numerous other participating utilities meet periodically to discuss topics related to market analysis, public education, technical features, customer experience, macro value analysis, and public policy.

Supporting New York City PlaNYC readiness study for Electric Vehicles—Helped analyze the expected grid impact of projected electric vehicle adoption in the five boroughs of New York City.

Engaged in Public Outreach—Provided a presence for consumer education at NYU Rudin Center for Transportation Research, Climate Week, NY Auto-Show, NYC Plug-In Day, OEM dealer product information links, and the Con Edison EV Website

DOE Infrastructure Planning Grant—Working with NYC Mayor’s Office of Sustainability and Planning and NYCLHV Clean Cities on integrated infrastructure planning incorporating the effects of DC fast charging

Residential and Fleet Adoption Mapping—Completed analysis of EV penetration by census tracts within the Con Edison service area

Opt-In Smart Meter Pilot—Piloting application of smart meter solutions to EV charging to demonstrate potential customer cost savings solutions

Based on what we know today, we expect that the primary utility challenges from PEVs will include system and distribution charging levels and integration with distribution operations. Con Edison will continue to develop and revise plans to address these issues based on our R&D and collaboration with leading thought leaders and industry associations.

System and Distribution Charging Levels

PEVs may represent a significant new source of electricity use for Con Edison’s electric distribution system in the future. This use will affect total system requirements as measured by consumption, and even more importantly will affect the distribution grid because of the relative concentration of PEVs on specific circuits or at peak times. The impact of new customer use on Con Edison’s system peak will be influenced by the number of PEVs on the system and when they plug in. Charging may be concentrated during the early hours of the day and after arriving at home from the office. This could result in dual charging spikes.

Con Edison recognizes that PEVs may change load-area peaks. These localized (early on in the introduction of PEVs the impacts may be very “lumpy”) changes will be more important than system peaks. PEVs in specific neighborhoods are likely to concentrate loads differently than at the system level. The result will be local circuit loadings significantly different than average system loadings. The fact that the PEV load is mobile will also present new planning challenges.

Controlled charging, accomplished through rate incentives or “smart charging” has the potential to shift charging load to night hours, when electricity demand is at its lowest. While PEV loads are not likely to be shifted completely to the night time, it is possible to significantly alter customer usage patterns with smart charging capabilities. This in turn will reduce the need for new transmission and delivery assets.

In addition, demand response and other forms of load management can be deployed to smooth circuit-level load impacts. Demand response mechanisms would allow Con Edison to control loadings
at specific times on specific circuits.

Con Edison’s residential networks, which typically peak between 8PM and 11PM, may require pricing incentives designed to promote charging after the peak or smart charging to avoid local area overloads. Additionally, the long commute times from counties surrounding New York City may also require more daytime charging in New York City than in other regions.

**Distribution Operations**

Increased peak load at night may reduce opportunities to perform maintenance, which is typically performed during periods of lower customer demand. In addition, the increased loading at night may change the thermal cycling of delivery assets and subsequently change our design specifications. These changes could lead to increased capital expenditures to reinforce our infrastructure. A study has begun to develop the required risk mitigation plans.

Our broader concern, however, is that PEVs must be integrated with the utility system at the distribution level. PEV charging interacts with metering, billing, system reinforcement, load control, and demand response management. Integration also requires coordination with utility information systems, as well as with operators. PEV integration is an example of a development that will benefit from Smart Grid technologies and AMI but does not require either for basic operation.

As Smart Grid technologies and advanced metering will impact the way PEVs interact with the electric system, including potential future vehicle-to-grid capabilities, we will continue to study and implement Smart Grid technologies that can identify electric vehicles using the electric system. This can be the solution to universal access to the electric grid for PEVs, and remove the barrier of requiring each PEV to have its own account with every utility before recharging.

### 3.4.3 Forecasts

Initial analysis of PEV penetration in our service territory indicates a range of scenarios, with varying assumptions around penetration levels by load area and charging patterns. For our plan case we have assumed a system-level, peak-coincident impact of 153 MW in 2031, illustrated in Figure 3-10.

There are a number of different forecasts available for adoption rates for electric vehicles. Our forecast is based on background studies obtained from GE and McKinsey’s PlaNYC mid scenario. Using income and driving patterns as the primary factors influencing adoption, our Plan Case forecast is for 380,000 electric vehicles registered in New York City by the year 2031. This represents approximately 15% of the current vehicle registration. PEV adoption for Westchester County is also incorporated into the estimates in Figure 3-10. This demand impact assumes that vehicles will be charged using smart charging equipment. In environments with time-based pricing, it is expected that many drivers will charge overnight to take advantage of lower cost of energy.
As discussed earlier, our plans to facilitate and manage the integration of PEVs into the grid must be focused on specific load areas as penetration may vary dramatically across our service territory, and system reinforcements will be specific to particular locations. The estimates in Figure 3-10 represent the aggregation of load-area specific estimates. Summarized by service territory, regional contribution to PEV load projections for 2031 is illustrated in Figure 3-11.
3.4.4 Signposts

The overall pace of adoption of PEVs will be influenced by a few key factors:

- **Driving range**—A roadblock to widespread utilization for electric vehicles has been their limited driving range, which is entirely predicated on the design of the batteries. Battery development is constrained by inherent tradeoffs between five main battery attributes: power, energy, longevity, safety, and cost. Two leading battery designs rely on nickel-metal hydride and lithium-ion. Other battery technologies are in various stages of development and many different types of chemical combinations are currently being tested to achieve the energy storage density needed to increase driving range and affordability, thus facilitating the widespread adoption of electric vehicles.

- **Interoperability**—Utility tariffs, which can be designed to accommodate not just local PEVs but also PEVs from other areas, will also drive adoption. The universality of fueling capability throughout the nation must be resolved; no one will buy a car that can’t be filled up outside of one’s own region. Billing becomes a technical issue that must be addressed through Smart Grid technology. This will require an integrated communications infrastructure and corresponding price signals. Smart chargers enabled by the Smart Grid will help manage the distribution infrastructure and allow for accurate billing.

- **Continued support for alternative fuel vehicles**—Government support will also be important to electric vehicle adoption, including current and proposed policies and plans, such as Federal policy and pending greenhouse gas legislation.
3.5 ADVANCED METERING INFRASTRUCTURE

Advanced metering infrastructure (AMI) is the combination of digital interval meters, supporting telecommunications, and information technology systems. AMI gives customers greater control over their energy bills and enables time-based pricing and demand response programs by facilitating two-way communication between the utility and the customer. These programs allow customers to adapt their behavior to lower their energy consumption and to shift their usage to less-expensive times of the day. Real-time information also allows consumers to better monitor their carbon footprint and enables them to curb behavior that has the highest environmental impact.

AMI can also facilitate a utility’s better control of its transmission and distribution system, and allows customers a more direct role in their electricity consumption. To support Con Edison’s mission to take an integrated approach to managing supply, demand, and environmental emissions impact, the Company plans to pilot and eventually strategically deploy AMI in its service territory, as needed.

AMI enables bi-directional communication with customers and increases Con Edison’s control of its system. This is achieved through features embedded in the meters, as well as by integrating the right supporting technology.

AMI technology being considered by Con Edison offers additional functionality and capability not found in the existing meters, including:

- Bi-directional registration
- Ability to provide time-stamped interval data at hourly (or shorter) time intervals
- On-board memory capable of storing at least 60 days of readings
- Real-time (time lag of 5 minutes or less), remote read-only access to meter data for customers and/or competitive providers
- Two-way communication, including the capability to remotely read meters on demand
- Ability to send signals to customer equipment to trigger demand response functions and/or connect with a home area network (HAN)
- Positive notification of outage/restoration
- Self-diagnostics, including tamper flagging
- Interoperability with Smart Grid applications (e.g., distribution automation)
- Remote disconnection/reconnection
- Ability to remotely respond to under-frequency conditions by reducing system loading
- Improved billing options to customers
The functionality of advanced meters is enabled by the installation and integration of supporting information and telecommunication technology. These may include:

- Local area networks that enable meters and modules to convey data and receive information
- HAN controllers and devices that enable customers to view and manage energy use
- A data acquisition system that links meters with back-office components, such as a meter data management system which collects meter information for billing and net metering
- Service relay technology for electric service connection/load limiting/disconnection
- The potential of incorporating meter data points into various analytical models used at the Company
- Compliance with cyber security standards

Con Edison views AMI as an important component of some of the initiatives outlined in this chapter and in the entire Electric System Long Range Plan. For example, demand response can only be relied upon as a firm resource if it is dispatchable, measurable, and verifiable, which can be implemented using AMI interval meters, data management applications, and bi-directional communications. Similarly, distributed generation cannot be fully integrated into the grid without the advanced metering functionality of AMI that tracks power sold back to the grid, and distributed generation cannot be relied on to lower peak capacity unless the utility can verify the load has shifted off of its system due to alternative generation sources. The integration of intermittent renewables is expected to have disruptive impacts on the grid unless the utility can quickly dispatch demand response and distributed generation resources. And, the expected conservation impacts of extending time-based pricing to the small commercial and residential segments cannot be achieved without interval meters and the supporting data management & telecommunications provided by AMI.
### 3.5.1 Objectives

Table 3-6 summarizes how AMI can potentially help us achieve our objectives toward managing supply, demand, and our environmental emissions impact.

#### Table 3-2. Potential Role of Advanced Metering Infrastructure in Achieving Objectives

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of Advanced Metering Infrastructure in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</strong></td>
<td>• By enabling demand response and distributed generation, AMI could allow the Company to meet its load shape objectives of shaving and shifting peak in load constrained areas allowing for deferred transmission and distribution investments and reduced power purchased costs.</td>
</tr>
<tr>
<td><strong>Help Customers Manage Energy Costs</strong></td>
<td>• AMI enables time-based pricing and demand response incentive programs to allow customers to adapt their behavior and lower their bills. System-wide reduction in peak capacity will lower capacity purchase costs, lowering the supply portion of customer bills. Commercial and industrial customers can leverage verifiable demand response and distributed generation (enabled by AMI) to avoid peak demand charges.</td>
</tr>
<tr>
<td><strong>Improve Environmental Profile and Meet Federal, New York State, and New York City Targets</strong></td>
<td>• AMI is the backbone for time-based pricing, which has significant conservation potential. It enables demand response, which is critical to smooth demand peaks with the interconnection of intermittent renewables, and it facilitates the interconnection of supply-side distributed generation, which can offset central fossil fuel sources.</td>
</tr>
</tbody>
</table>
| **Enhance Reliability** | • AMI may improve reliability by reducing outage duration via real-time monitoring of the distribution network. Quicker outage detection and the enhanced ability to locate where an outage has occurred will allow the utility to dispatch repair crews directly to the location and improve verification of service restoration.  
  • AMI enables dispatchable and verifiable demand response, which when deployed as a load relief mechanism may increase reliability and stability of the distribution network during multiple contingencies or underfrequency conditions by reducing peak loading of distribution transformers.  
  • Without AMI, which enables dispatching and measuring demand and supply resources, the use of intermittent renewables could impact service. |
| **Diversify Supply Portfolio** | • AMI could be critical for Con Edison to integrate intermittent renewables into the grid, as it enables dispatch and measurement of demand and supply resources. The Company would be able to |
There are two other core benefits of AMI:

First, AMI provides increased visibility and control, which are the foundation of Smart Grid. Much of the customer benefit of a Smart Grid infrastructure relies on the capture of detailed data that is timely enough to communicate the status of the utility distribution system to process-intelligent controls for the distribution equipment. AMI can potentially capture non-traditional data, such as voltage and current information, at the customer level for Smart Grid applications. In addition, the implementation of a meter data management system and integration of AMI data with distribution management systems, outage management systems, and other systems will provide the information and intelligent control necessary to facilitate the operation of the Smart Grid.

While Con Edison already has many elements of a Smart Grid, AMI will specifically help to enhance the visibility into and control of our distribution network by:

- Enhancing quantity and quality of data for monitoring and modeling for improved asset management
- Enriching data for distribution automation
- Integrating and monitoring new end-use devices, including electric vehicles
- Providing customer end-point data to enhance the value of the Secure Interoperable Open Smart Grid Demonstration project
- Facilitating dispatchable demand and supply resources
- Enabling advanced building and appliance automation

Second, AMI enables a number of operating efficiencies. Operations and maintenance (O&M) and capital savings could be attained from the following:

- Reduction of manual meter reading
- Improved meter accuracy
- Reduction of off-cycle reads
- Reduction of estimated reads
- Reduction of revenue losses from unoccupied premises
- Reduction of load research costs
- Reduction of call center inquiries and call resolution time
- Reduction of compensation and claims for meter reading
- Offset metering capital costs
3.5.2 Implementation Plan

Recognizing the importance of deploying the right technology in the right areas, Con Edison preceded potential wider-scale AMI deployment with a pilot in a representative sample of its system. Once the benefits of the pilot are validated, the Company will present its findings to the PSC in hopes of eventual wider-scale deployment of the technology. This AMI pilot was completed in the Long Island City network in 2011 with the installation of 1,500 meters. During this period, Con Edison tested communication solutions, in-home devices, 300 home area networks, transformer and network protector monitoring and control, electric vehicle charging, and feeder reconfiguration. As previously stated, this pilot was designed to better inform and validate the benefits of broader AMI deployment in New York City and Westchester County.

A new pilot will also begin in 2012 focusing on an opt-in approach to AMI targeting a limited number of PEV customers. The pilot will utilize carrier-based communications at the meter to offer AMI to those customers that can directly benefit from the technology while eliminating the need to invest and deploy in the communications infrastructure of a traditional AMI implementation.

In last year’s plan and in accordance with Con Edison’s targeted approach to system investments, the Company suggested focusing future AMI deployment on networks facing reliability or capacity constraints. By potentially deploying AMI in these networks, Con Edison could be responsive to customer reliability needs and defer near-term transmission and delivery investment through verifiable and measurable demand response and distributed generation.

Thirty targeted networks (or load areas) were selected based on capacity and reliability constraints as determined by an evaluation of network reliability indices and expectations for the need to relieve future area substation and localized capacity constraints.

Furthermore, if the pilots would prove to be successful, the Company would plan for a targeted deployment to begin in 2013, eventually reaching a total of 1.5 million meters (45% of total electric meters). Fifty percent of the meters would be installed in the first three years and, implementation would be complete after six years (in tandem with gas meter replacement). The meter deployment schedule would also be aligned with the Company’s demand response programs. However, the “green light” for wide-scale AMI deployment has yet to come to fruition for the Company.

36 A number of initiatives and R&D projects may rely on the AMI communications network. The Company presently incurs costs for stand-alone, special data communications networks that are currently associated with some of these projects and initiatives. The use of the AMI infrastructure could potentially reduce the cost to gather data from various remote field devices. Specific projects include: Automation of 480V Vaults, High Tension Monitoring Data Acquisition System, and Meters for Unmetered Services

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Back in 2007, the Company filed for approval of wider-scale deployment of AMI, but the request was denied until a more substantial cost/benefit analysis was completed and until the New York Public Service Commission (NYPSC) adopted minimum functional requirements of AMI systems in New York State\(^\text{37}\). These functional requirements were ordered in early 2009\(^\text{38}\), just prior to the application submission date for Smart Grid Investment Grant funding from the Department of Energy (DOE) via the American Recovery and Reinvestment Act of 2009.

Therefore, the Company decided to apply for wide-scale AMI funding through the ARRA and DOE, with hopes that they would supply 50% of the required costs. However, that request was denied, and therefore, so was the matching 50% that would have come from ratepayers. Furthermore, in Case 10-E-0285 issued in mid-2010, the NYPSC expressed additional doubts about AMI, such as whether replacing the AMR in our system with AMI for a marginal increase in functionality would be cost effective.

Given their reservations, the NYPSC took a very thorough and conservative approach and initiated an inquiry, which is still ongoing today, to field ideas on grid modernization regulatory policies from a broad spectrum of stakeholders, including academia, consumer representatives, and telecommunication companies, in hopes of obtaining more information on the materialization of benefits from smart grid projects around the country\(^\text{39}\).

Given the current regulatory climate on the topic, we will continue to review any specific, strategic opportunities for smaller-scale AMI deployment within the guidelines set forth by the NYPSC.

### 3.5.3 Cost Benefit Analysis\(^\text{40}\)

Because of the aforementioned regulatory sentiment towards wide-scale AMI implementation, the Company has not conducted an updated cost-benefit analysis for the initiative. However, below we will describe the cost-benefit approach taken in last year's plan.

After we evaluated various alternatives in the previous plan, it was determined that a targeted deployment of AMI with 1.5 million meters could position Con Edison to leverage the functionality of AMI while continuing to test the benefits of broad scale deployment. As it was planned, we estimated that targeted electric AMI in the Con Edison service territory could provide an 18-year\(^\text{41}\) net present value of $71 million. Rollout of this program was expected to begin in 2013; the Company planned to utilize the results of the pilot program to enhance this program as necessary. The targeted approach would have allowed the flexibility to ramp up to a full deployment without all sunk costs being incurred. Figure 3-12 summarizes the breakdown of the cost and benefit categories that made up the AMI business case.

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\(^{37}\) Case 94-E-0952 – In the Matter of Competitive Opportunities Regarding Electric Service.

\(^{38}\) Case 09-M-0074 – In the Matter of Advanced Metering Infrastructure.

\(^{39}\) Case 10-E-0285 – Order Instituting Inquiry Into Smart Grid

\(^{40}\) This analysis was conducted for the 2010 Long Range Plan

\(^{41}\) An 18-year Net Present Value represents the time from the initial rollout of the program, in 2013, to the end of the plan time horizon in 2030
3.5.4 Signposts

With the completion of the pilot, Con Edison is in the process of validating its cost and benefit information. The company will revisit its AMI implementation strategy based on the regulatory climate, the intelligence collected from the pilot, as well as from closely monitoring its business environment. The Company has developed signposts that, if necessary in the future, could trigger the review and adjustment of its plan at any point in time. Some of the areas that will be monitored are:

- **Load Growth**—Low or negative load growth will limit the need to manage peak demand
- **Linkages to Smart Grid and distributed generation strategy**—AMI as an enabler of operational savings and demand response is only part of the rationale for the investment. Depending on our Smart Grid strategy, AMI could be necessary to enable more advanced initiatives, such as enhanced automation and modeling.
- **Regulatory/Legislative Guidance**—As in other states and as previously mentioned, the regulatory climate will be the largest driver of the pace of adoption of AMI.
- **Technology Obsolescence**—Over the 20-year planning horizon, there is a chance that traditional meters will no longer be commercially available.
- **Evolution of home area networks**—Breakthrough in home area networks could change the role of the meter relative to customer energy management.
- **Benchmarking**—The successes and challenges of other utility deployments.
3.6 NEW TRANSMISSION

Transmission projects offer another way to access renewable or less expensive sources of generation and to maintain or improve reliability. The Company recognizes and supports examining transmission projects that achieve these goals, but only to the extent that reliability is maintained and the transmission project is the most cost effective method, as compared to local generation or energy efficiency, for achieving those goals. The primary threshold for any transmission project is the project’s impact on system reliability. Each merchant generation or transmission project requesting to interconnect to the Con Edison grid must meet a strict set of publicly posted reliability standards. This review takes place under the supervision of the New York Independent System Operator (NYISO) through its interconnection process tariff, which includes individual project studies, the system reliability impact study (SRIS), and the class year deliverability and cost allocation studies performed jointly for all projects in the class year. Con Edison is an active participant in those studies.

In order to study the transmission needs in New York State in the future, the Company is involved in the New York State Transmission Assessment and Reliability Study (STARS), a joint effort initiated by the transmission owners in New York State and supported by the NYISO, with the goal of studying the bulk power system throughout the state to assess its ability to meet the future needs of New York State residents through around 2028. Phase 1 of the study confirmed that transmission reliability needs depend on where generation is sited (i.e. none needed if generation locates close to load). Phase 2, nearing completion, is examining the Benefit to Cost ratio for a number of transmission upgrades or new projects. Moreover, the current NYISO interconnection queue indicates a high probability of substantial new generation in and transmission into New York City. Con Edison may invest in transmission as a result of the potential projects that will be identified by this study.

3.6.1 Objectives

Table 3-7 explains how transmission projects, as part of a portfolio of solutions, may help achieve our objectives of managing demand, supply, and environmental emissions impact.

<table>
<thead>
<tr>
<th>Objective</th>
<th>Role of New Transmission in Achieving Objectives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduce Transmission &amp; Distribution Infrastructure Investments and Power Purchase Costs</td>
<td>• Building new transmission could enable integration of less expensive sources of supply, thus lowering purchase power costs or compensate for potential generation retirements.</td>
</tr>
<tr>
<td>Help Customers Manage Energy Costs</td>
<td>• New transmission projects may be utilized to interconnect the Con Edison transmission system with more diverse supply sources, providing a hedge against risk from volatile commodity price changes. In addition, new transmission projects may offer a way to potentially reduce congestion costs.</td>
</tr>
</tbody>
</table>
Improve Environmental Profile and Meet Federal, New York State, and New York City Targets

- Transmission projects can connect to cleaner and/or renewable fuel sources, which in conjunction with local renewable energy supply sources, may reduce greenhouse gas emissions and help both New York State and New York City meet their renewable energy targets.

Diversify Supply Portfolio

- New transmission projects, if they provide access to renewable resources, may also help to diversify our supply portfolio.

### 3.6.2 Implementation Plan

As noted above, there are no transmission projects that currently appear to be needed for reliability or economic reasons. In the longer-term there may be an opportunity to build new transmission to integrate bulk renewables into the overall generation mix. The combined costs of transmission projects with remote generation, however, must continue to be compared against the cost of adding new local generation and against the cost of demand side management programs to offset additional load growth. Figure 3-13 illustrates that Con Edison’s transmission projects generally fall into three phases.

![Figure 3-103. Implementation Plan: New Transmission](image)

Three generation/transmission projects, occurring during Phase I, which highlight CECONY’s goal of integrating bulk renewables and/or affordable supply, are the Bayonne Energy Center (BEC) Project, the Hudson Transmission Partners (HTP) Project, and 2nd Ramapo to Rock Tavern Circuit Project.

The Bayonne Energy Center (BEC) Project is a 500 MW combined-cycle project currently under testing which will interconnect a new 500 MW facility located in New Jersey to the Con Edison Gowanus 345 kV substation. The project is scheduled to be fully operational prior to summer 2012.

The Hudson Transmission Partners (HTP) Project will interconnect the PJM system to the Con Edison system by means of a back-to-back HVDC facility with a 345 kV cable into the Con Edison W49th Street substation. Although the project’s capability is 460 MW, it will initially provide 320 MW. The project is scheduled to be fully operational by summer 2013.

The company has just placed into the NYISO interconnection queue a project consisting of the second circuit on a double circuit tower line between Con Edison’s Ramapo substation and Central Hudson’s Rock tavern substation. This facility is current under consideration and no final decision has yet been made on committing to its construction.
It is possible that within the near-term technology changes will occur that will add to the affordability and availability of renewable sources of generation. As such, in Phase II the Company will seek to identify opportunities to connect to these resources to help meet any Federal renewable portfolio standard targets and greenhouse gas objectives, as long as the connection of these sources does not include an unwarranted cost burden on our customers for transmission lines that have not been deemed necessary for reliability.

During Phase I and again in Phase III Con Edison expects to be involved with transformational opportunities that will enhance the capabilities of the business. These transformation drivers should come from both policy initiatives as well as technological advancements, and Con Edison is committed to utilizing any and all measures that will have significant cost and environmental benefits for customers.

### 3.6.3 Estimated Costs

Building new large transmission projects is an extremely capital intensive endeavor, and several business models exist for the ownership and operation of transmission assets. The two most common models are for transmission assets to be owned by utilities, generators and municipalities or for the assets to be owned by independent transmission companies. Con Edison’s position is that joint ownership of transmission assets by New York State’s utilities should be encouraged as an effective and equitable way to finance any new transmission that would, for example, reduce congestion or achieve societal goals like greenhouse gas reduction.

The New York Independent System Operator operates a competitive wholesale market and accordingly maintains a market-based philosophy with regard to the need for transmission and generation assets. Only in situations where market based proposals are insufficient to meet identified reliability needs will regulated solutions be required to maintain reliability. Costs of regulated transmission projects necessary to maintain system reliability are recovered consistent with rules specified in the New York Independent System Operator’s tariffs on file with the Federal Energy Regulatory Commission (generation and demand-side management projects are subject to the PSC’s jurisdiction). Further, costs of regulated transmission projects that reduce congestion and provide statewide economic benefits may be passed through to customers via economic planning rules (also outlined in the New York Independent System Operator tariff) if the project receives 80% or more approval from the project’s intended beneficiaries.

The Federal Energy Regulatory Commission (FERC) has ultimate jurisdiction over transmission projects. To promote transmission investment, the FERC has defined several incentives, including ROE adders on new investments that owners of transmission assets that meet certain requirements are allowed to earn. Projects, which are approved in a regional planning process, generally qualify for these returns.
3.6.4 Signposts

In order to be adaptable to the marketplace, Con Edison has defined a number of signposts that will identify changing needs and sentiments of the market and that could require modification of the overall strategy.

- **Enactment of more stringent Federal renewable portfolio standards and greenhouse gas laws**—Federal targets that are more aggressive than New York State targets may provide increased impetus for the interconnection of renewable sources of generation.

- **Dramatic changes in the sources or amount of supply available**—Dramatic changes in supply availability could affect the need for additional transmission assets, for example, Entergy failing to renew the operating licenses of the Indian Point Units 2 and 3, which would result in their retirement at the end of September 2013 and December 2015, respectively.

- **Increased proliferation of storage technology**—Proliferation of new storage technologies may alter the need for additional transmission assets.

- **Changes in federal regulation and oversight**—Policy regarding Independent System Operators, Regional Transmission Operators, and Interconnection-Wide Planning Requirements can have a significant impact on the entire transmission industry.

- **Results of New York State Transmission Assessment and Reliability Study**—Results could call for changes to be implemented by various New York State transmission entities in order to meet the needs of customers and ensure reliability (but does not appear likely at this time).

- **Changes in customer demand for cheaper or cleaner sources of energy**—Dramatic changes in customer requirements, including conservation measures, could impact the pursuit of additional transmission projects.

Throughout the three phases of implementation, Con Edison will continuously monitor these conditions, and adjust programs as necessary. As the internal and external environments change, additional signposts may be identified and added to this list.

3.7 SUSTAINABILITY INITIATIVES

Con Edison has a long standing commitment to protect the environment. Our Sustainability Strategy is a plan to reduce the Company’s environmental impact, encourage and assist customers in managing energy use, build partnerships with stakeholders to support our vision, and develop infrastructure for clean energy alternatives. Long-term objectives of this strategy include: integrating more sustainable choices in the Company’s decision making, enhancing our role in policymaking, and improving stakeholder relations. This strategy is constructed of six key principles incorporating environmental, social, and financial considerations:

- Model green behavior internally
- Promote green behavior to external stakeholders
- Innovate to meet customer preferences for a greener lifestyle
- Partner with government to shape policies and standards consistent with sustainability vision
- Develop infrastructure to advance the use and delivery of value-creating clean energy alternatives
- Incorporate environmental and societal value into our decision making

Sustainability is a business imperative, as well as a global imperative. We will continue to refine and expand our efforts so that the way we conduct business contributes to a more sustainable future. Figure 3-14 summarizes the greenhouse gas reduction goals for our environmental sustainability initiatives and the Electric System Long Range Plan through 2031.

**Figure 3-14. Targeted Greenhouse Gas Emissions Reduction in 2031**

![Graph showing greenhouse gas reduction targets in 2031](image)

### 3.7.1 Summary of Initiatives

**Model Green Behavior Internally**

Con Edison is a user of energy as well as a provider, so we continue to examine our own consumption patterns. The primary greenhouse gas emissions generated by the company include carbon dioxide, sulfur-hexafluoride (SF₆), and methane. Greenhouse gases are reported using carbon dioxide equivalence, or CO₂e, a standardized unit that accounts for the differing warming potentials of the various greenhouse gases. In 1999, Con Edison entered into a memorandum of understanding with the EPA, voluntarily agreeing to reduce its sulfur hexafluoride (SF₆) emissions. Since signing the agreement in 1999, through 2011, Con Edison reduced its SF₆ emissions by more than 90% through an aggressive equipment replacement and leak detection program.

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42 Direct and New Generation emission reductions are estimated based on anticipated project completion by 2020; Customer Reductions are estimated based on approved EEPS projects as of January 2011.
Greening Our Premises

New York City’s skyline grew greener when we installed energy efficient lighting in the tower of our corporate headquarters. At night, the tower uses 63% less energy than conventional lighting, lowering carbon emissions by roughly 19 tons a year. Another goal for the company is to reduce employee electricity consumption at company office locations 15% from 2005 levels by 2015. Meeting this goal will conserve an estimated 6,600 MWh of electric consumption annually. Through 2011, the company has been working on a major renovation at the 4 Irving Place location as well as a number of energy usage upgrades at locations throughout the service territory.

We believe that a significant energy use reduction can be achieved through upgrading the Company’s roof space as well. In 2008, we installed our first green roof at our training facility in Long Island City, in cooperation with Columbia University’s Center for Climate Systems Research. Thousands of plants are keeping the building cooler in summer and warmer in winter. Where green roofs are not always practical, the company is applying a white roof coating to locations throughout the service territory. The Company is helping the City meet its 1 million square foot goal with a contribution of 30 roofs, accounting for 250,000 square feet of roofing, covered at locations such as 4 Irving Place, College Point, and the Energy Control Center. Over 200,000 square feet of white roofing has been added through 2011 with an additional 400,000 square feet of potential white roofing identified throughout the various boroughs at various Con Edison locations. We will continue to evaluate all new Company construction and renovation projects, as well as operation and maintenance of our existing buildings, to conform to reduce the impacts of our buildings.

A green awareness campaign, improved waste segregation, and the qualification of additional recycling vendors will assist in achieving a recycling rate at our facilities that is greater than or equal to industry-leading standards. The Company currently recycles 90% of the solid non-hazardous waste generated in its operations throughout NYC and Westchester County. We will continue to identify new opportunities for recycling, and will work with vendors on meeting sustainability criteria and performance.

SF₆ Emission Reductions

Sulfur hexafluoride (SF₆) is used as a dielectric to extinguish the circuit breaker arc and as an insulating medium in different pieces of equipment, such as enclosed bus arrangements. As it has been identified by the Intergovernmental Panel on Climate Change as a potent greenhouse gas, the Company has committed to the Environmental Protection Agency (EPA) to reduce SF₆ emissions annually by 5% from a 1996 baseline. Through 2011, Con Edison reduced its SF₆ emissions by more than 90% through an aggressive equipment replacement and leak detection program.

To reduce SF₆ emissions, the company has accelerated equipment replacements and improved its ability to identify and repair leaks. Specific initiatives include:

- Establishing SF₆ reclamation centers and the use of “gas carts” (recycling units) that enable the Company to recover, purify, and reuse SF₆.
- A laser imaging camera that displays leaking SF₆ on a video monitor. This allows users to pinpoint the precise location of the leak and take corrective measures. This also greatly reduces the time it takes to locate leaks, resulting in fewer outages.
- Regular periodic internal inspection of SF₆ equipment.
**Leak Detection, Location, and Prevention (Dielectric Feeder Oil)**

In addition to conventional leak detection methods (i.e., low-reservoir-level alarm, frequent-pumping alarm, low-pressure alarm), we employ innovative On-Line Leak Detection. This system remotely monitors cable systems, and detects small differences between the predicted and actual fluid entering the system. Data is monitored and transmitted to our control center in real-time. The solution enables more accurate leak detection by analyzing the relationship between pipe and soil temperatures, fluid pressure, and conductor current.

In collaboration with Electric Power Research Institute and the Brookhaven National Laboratory, we have tested a variety of methods to pinpoint leaks. The most advanced of these is the PFT Leak Location Method. This involves injecting the affected cable systems with a per-fluorocarbon tracer (PFT), allowing it to run through the cable system, and then detecting its vapors with our PFT Leak-mobile.

Our crews employ leak prevention methods, such as maintaining cathodic protection systems, isolating termination ruptures, replacing leak-prone sections, inspecting manholes, and detecting corrosion and coating disbonding.

**Con Edison Fleets**

Since January 2008, diesel vehicles have been using cleaner-burning B-20 biodiesel fuel. By volume, 20% of this fuel is derived from soybeans. The soy-based portion of the fuel is a renewable resource that will help the company offset almost 400,000 gallons of petroleum per year. Newer diesel vehicles also will be equipped with special exhaust filters for even cleaner tailpipe emissions. At the close of 2011, 42% (1,735 vehicles) of the Con Edison fleet runs on biodiesel. An additional 8% of the fleet consists of either CNG (129), hybrid (199), or plug-in electric (5) vehicles. All vehicle operators have strict guidelines for limiting vehicle idling when it is not an operational requirement.

**Mitigating Past Harm**

The Company also manages environmental-related issues and risks that resulted from historical operations. The Company's mitigation activities are currently focused on the following:

- Monitoring and managing various Superfund sites
- Investigating and, if necessary, remediating old oil and dielectric fluid spills at various locations
- Performing corrective actions related to the Company’s Astoria site43
- Investigating or remediating, if necessary, the contamination that resulted from underground storage tanks (USTs)44

43 Under the Company’s agreement with the Department of Environmental Conservation (DEC) and in compliance with the Resource Conservation and Recovery Act (RCRA).

44 These USTs are subject to EPA and DEC standards and the Company currently has 9 sites where it is actively pursuing investigation or remediation activities. Typically, Con Edison owned or operated these sites as part of service centers and other facilities that were used to support operations. Its investigation efforts often involve groundwater and soil testing.
Investigation and remediation, if necessary, of Manufactured Gas Plants (MGPs), which were part of the Company’s original gas business

Promote Green Behavior to External Stakeholders

Con Edison encourages its customers and the public to make sustainable choices. Our broad communications program includes advertising, websites, social media, and speaking engagements to educate the public. The Power of Green website offers more than 100 energy-saving tips that customers can easily implement in their own homes. Of particular interest are the home energy calculators, which allow customers to determine how much energy their appliances use, so they can make informed decisions about how and when they use them. Energy efficiency tips are also featured on subway ad campaigns, radio commercials, in printed brochures, and our Customer News bill insert that reaches more than 3 million customers.

We have also extended green communications to one of our most important stakeholder groups—our employees. The Greening House campaign delivers messages about how the company is greening the way it does business, one story at a time. Through messages on elevator screens, and on the company’s intranet, Greening House also encourages employees to do their part for a more sustainable future. The Greening House Ideas program is an electronic suggestion box where any company employee can suggest ways that the company can become more sustainable. Every idea submitted is responded to, and a number have been chosen for feasibility studies.

The company also supports an economy-wide cap and trade system as a means to regulate greenhouse gas reduction. Furthermore, as federal and state agencies establish rules for the implementation and cost accounting for these programs, the company will maintain a position toward redistribution of electric generation carbon funds to utility-run energy-efficiency and renewable-energy programs. Concurrently, we support real-time pricing for all customer classes and support the adoption of AMI to facilitate variable pricing and to provide associated information to help customers better manage their energy consumption.

In addition, the company supports more than 1,200 nonprofit organizations that help strengthen neighborhoods, sustain communities, and improve lives. Our community partnerships support the arts; environmental stewardship; civic awareness; and science, technology, engineering, and mathematics education. We support green education programs in local schools, and contribute to nonprofit organizations that help create green spaces and community gardens. We are proud to be a leading benefactor of the New York Botanical Garden and a sponsor of its Greening the Garden program.

Innovate to Meet Customer’s Preferences for a Greener Lifestyle

New York State has created a number of programs designed to achieve the clean energy policy goals contained in the RPS, EEPS, SBC and RGGI policies. As described earlier in this chapter, the Company supports the New York State Energy Efficiency Portfolio Standard and Renewable Portfolio Standard, and seeks greater participation by utility companies in interfacing with customers on incentive programs devised to reduce customer demand. These programs are supported by collections from electric and natural gas customers of Con Edison. The Company has an interest in evaluating these programs to make sure benefits are being delivered to our customers in the most cost effective manner possible; however at the same time, the Company supports these programs because they help achieve benefits desired by our customers: cleaner air and a healthier environment.
The Company also enrolled 85,499 e*bill (electronic bill) customers in 2010, and has added 98,636 more in 2011, as New Yorkers continue to focus on small changes they can make to help save the environment. Con Edison donates $1 for each customer that switches from paper bills to electronic e*bills. With these donations, the Company has helped plant more than 10,600 trees throughout New York City to support the New York Restoration Project and MillionTreesNYC. MillionTreesNYC is a PlaNYC initiative launched by Mayor Michael Bloomberg and the entertainer Bette Midler with the goal of planting one million trees across the city’s five boroughs by 2017. Including Con Edison’s contribution, the effort is more than halfway to its goal, with over 558,000 trees already planted.

**Partner with Government to Shape Policies and Standards Consistent with Sustainability Vision**

Con Edison will continue to build coalitions with stakeholders to implement policies and programs that support our vision. We will maintain transparency with stakeholders. A key component of a government partnership will be Public Service Commission endorsement of our Sustainability Strategy. This partnership would include broadening our energy advocacy to support public transportation infrastructure that uses energy efficiently and improves sustainability. Federal agencies have developed a significant number of voluntary and partnership programs, and the path to implement fully the Sustainability Strategy will include recognition of the Company’s efforts by Federal regulators. All of the other stakeholders noted above will be cognizant of the Company’s efforts, and the Company will be considered a resource for input to responsible policy development in efforts to advance the principles of sustainability.

**Develop Infrastructure to Advance the Use and Delivery of Value-Creating Clean Energy Alternatives**

As described earlier in this chapter, Con Edison is committed to advancing cost-effective and responsible use of renewable and distributed generation. We will do this by facilitating and incenting customer use of distributed and renewable energy and by promoting the development of an advanced metering infrastructure which will facilitate the sharing of customer-sited energy back on to the grid.

We will also work to expand our options for delivery of cleaner and renewable energy. The Company will also work in concert with The Electric Power Research Institute, PEV manufacturers, utilities, and other stakeholders to support the adoption of electric vehicle technologies with aggressive R&D initiatives.

Where applicable on our system, Con Edison will promote the development of a “smarter grid” to allow for the integration of intermittent renewable generation and to improve the overall efficiency of energy distributed on our network. The following initiatives are being deployed or tested:

- Demand response to absorb short-term load shortfalls due to the intermittency of renewables
- Storage to accompany intermittent distributed and renewable energy resources
- Voltage management to allow for the safe integration of intermittent resources
- Automated metering to allow for effective dispatch of distributed energy and demand response resources
Incorporate Environmental and Societal Value into Our Decision Making

Con Edison will consider the potential environmental and societal impacts of our business decisions. To this end, we will evaluate and measure opportunities to enhance sustainability characteristics within individual and enterprise wide projects. These concepts have been proceduralized through the introduction of CEHSP 11.03 - Environment, Health and Safety Considerations In Planning and Design of Project or Routine Work.

The Company is also committed to working together with other stakeholders to develop appropriate frameworks for the State’s Climate Action Plan. The Company has representatives on two Technical Work Groups: (1) Power Supply and Delivery and (2) Adaptation, as well as the higher-level Integration Advisory Panel.

We will monitor any developments from the State’s Climate Action Plan as signposts for the Electric Long Range Plan.

3.7.2 Recognition of Accomplishments

We strive to be a leader in the industry in terms of managing our environmental impact and have been recognized by several external entities, including the acknowledgements listed below:

- In 2011, ranked first among utilities in the S&P 500 Carbon Disclosure Leadership Index and was the only utility listed in the S&P 500 Carbon Performance Leadership Index.
- Named top utility by Newsweek Green Ranking in 2011
- Named for the third year in a row in 2011 to the Dow Jones Sustainability Index (DJSI), which recognizes corporations for economic, environmental, and social excellence
- Became a founding member of the Climate Registry in 2008 to voluntarily report greenhouse gas emissions, and have emission statements verified by an accredited 3rd party verifier
- Have been awarded $181 million in smart grid stimulus funds to modernize the electric grid in the most complex energy market in America.
- Recognized by the United States Environmental Protection Agency for replacing paper insulated lead-covered cable with nonlead solid dielectric cable
- Received a 2009 EPA award for SF₆ emission reduction by replacing equipment, thereby preventing 670,000 lbs of SF₆ from entering the atmosphere between 1999 and 2009
- Received the 2007 Financial Times/Citi Private Bank Environmental Award for the greatest improvement in carbon efficiency by any large corporation in the Americas
4.0 INTEGRATING INNOVATIVE SYSTEM DESIGN

4.1 INTRODUCTION

We design our electric system to meet customers’ growing demand for electricity and to maintain reliability. A core principle of Con Edison’s system design approach is the use of tailored solutions to fulfill these requirements. Tailored solutions apply targeted demand and supply side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas. Our tailored approach will result in the application of solutions where they can provide maximum benefit for our customers.

The expectation for world class reliability in New York City and Westchester County has led our system design to be robust and necessarily redundant. Due to this redundancy we have more distribution components per customer than other utilities. The sheer number of any given type of component on our system means that implementation of any wide scale investment program is higher in cost, even on a per customer basis. Our strategy, outlined in this chapter, is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, and ensure employee and public safety.

In section 4.2 we describe how we design our system and emphasize the steps we have taken to improve the cost effectiveness of our network by systematically incorporating alternative solutions to meet customers’ growing demand for electricity. In section 4.3 we introduce some of the specific innovative designs and advanced technology that we deploy to meet system requirements at a lower cost than traditional infrastructure enhancements without sacrificing reliability. In section 4.4 we discuss our ongoing exploration of changes to our rigorous design standard that would address our high asset intensity. And, in section 4.5 we introduce our research and development function tasked with continually developing advanced technology and design solutions to serve the unique needs of our customers. In sections 4.6 and 4.7 we provide signposts upon which to re-evaluate the strategy presented here and summarize the conclusions from this chapter.

4.2 TAILORING SYSTEM DESIGN

4.2.1 Meeting Customers’ Demand for Electricity

The Company’s obligation to meet the electricity delivery demands of our customers requires us to expand and reinforce our electric delivery system based on customer usage. Chapter 3 of this report highlighted the Company’s specific efforts and processes to manage our customers’ supply and demand in order to reduce the need for capital expenditure. However, even with a host of demand and supply side management programs, certain portions of the system will grow and require capacity replacement or expansion.
Expenditures for Meeting Customers’ Electricity Demand

Figure 4-1 presents a summary of the Company’s capital expenditures over the plan horizon, 2011 to 2031.

Figure 4-12. Con Edison 20-Year Capital Spending Summary

![Summary of CECONY's Capital Expenditures 2011-2031 ($, billions)](image)

As seen in Figure 4-1, ‘Reliability’ and ‘Replacement’ expenditures, which are for maintaining the reliability and safety of the existing electric system, represents a significant portion of the expenditures with 40% of the total. Our approach to managing these categories is described in detail in Chapter 5.

Chapter 4 describes the initiatives we employ to ensure our system meets customer demand, referred to as ‘System Expansion’ in Figure 4-1, which represents approximately 42% of the Company’s total capital plan. This mix of spending is consistent with spending at other large U.S. investor owned electric utilities.

45 ‘Common’ and ‘Other’ expenditure includes general or supporting investments such as information technology, common plant, and small investments in our few remaining power production plants. ‘Interference’ expenditure includes work needing to be done in conjunction with public improvement projects.
Figure 4-2 provides a further breakdown of the ‘System Expansion’ expenditure and reveals that a vast majority, 93%, of the Company’s investments in this area consists of distribution and area substation expenditures.

**Figure 4-2. Composition of System Expansion Investment**

(2011-2031)\(^{46}\)

<table>
<thead>
<tr>
<th>System Expansion (2011-2031)</th>
<th>Total</th>
<th>S&amp;TO</th>
<th>SSO</th>
<th>Electric Ops</th>
</tr>
</thead>
<tbody>
<tr>
<td>Billions</td>
<td>$10.94</td>
<td>$0.82</td>
<td>$2.36</td>
<td>$7.75</td>
</tr>
</tbody>
</table>

**Nature of System Expansion Planning**

It takes several years to plan, site, and construct major new assets like substations and transmission lines, especially in urban environments like metropolitan New York. Consequently, the Company maintains a long term perspective with regard to its planning and forecasting activities. It is not possible to precisely predict customer demand 5, 10, or 20 years in the future. This is especially true in an era characterized by evolving technologies and policies, volatile and uncertain prices, and changing economic patterns. We must therefore develop flexible plans that prepare for but not over-commit to capacity related initiatives.

\(^{46}\) Totals do not add precisely due to rounding.
Figure 4-3 illustrates the Company’s historic and projected transmission and distribution substation investment from 1948-2031. Capacity planning (i.e., load relief) occurs at both the transmission and the distribution levels of the Con Edison System. The Company’s transmission planning is conducted in concert with the New York Independent System Operator, which incorporates our local transmission plans into a statewide bulk transmission planning process.

**Figure 4-3. Substation Construction (1948-2031)**

Balance and flexibility are critical attributes of the Company’s load relief planning and implementation. Committing to major capacity expansions well in advance of need may result in excess capacity, add additional infrastructure cost, and add to the Company’s asset intensity challenge. Conversely, delaying capacity-related initiatives can increase cost as the availability of land decreases and the price of property increases. Our capital planning process seeks to optimize the timing of investment in order to take advantage of opportunities to minimize cost.

### 4.2.2 Tailored Solution Approach

In the past several years, the company has adopted and intends to continue to develop and improve its integrated and tailored approach to meeting customer demand. This tailored approach is designed to move the Company beyond traditional capacity expansion methods (i.e., construct additional assets to serve load) to create a tailored solution to each specific need.
Figure 4-4 illustrates the generalized steps in the load relief planning process. It commences with independent forecasts of customer demand that integrate various assumptions and planning horizons (Step 1). In concert with the system capabilities (Step 2), specific local system needs are identified and potential solutions or options are defined (Step 3). These options are evaluated (Step 4) and the optimal solution is defined. The Company’s selected plans are combined into a comprehensive plan (Step 5) to initiate various planning, budgeting, and engineering activities.

**Figure 4-4. System Expansion Planning Process**

1. Independent Demand Forecasts
2. Substation and Feeder Capabilities
3. Identify System Expansion Needs and Options
4. Evaluate System Expansion Solutions
5. Recommend and Issue System Expansion Plan

The Company’s traditional solutions for meeting customer demand – adding equipment to increase capacity, constructing new area substations and transmission lines, splitting or shifting of load among networks, etc. – are typical across utilities. This approach has been relied upon for decades and will necessarily continue to be employed. It has provided the necessary capacity for the growing electricity needs of our customers. This approach could lead to large units of incremental capacity expansion, thus initially lowering the overall system asset utilization until load growth catches up. In the past this approach was dependent on incorporating demand and supply side measures on a system-wide level. Figure 4-5 illustrates this traditional approach to capacity expansion planning. This does not lend itself to the detailed load area planning we need to do at the area substation and network or load area level.
We are now looking to incorporate contributions from distributed generation, energy efficiency, and demand response measures into our load area level forecasts to a greater extent than we have in the past. Advancement in measurement and verification, once implemented, will facilitate this process. This ability to identify area-specific demand reductions from demand management, as well as new infrastructure investment has led us to develop our tailored design approach as a more effective way to serve the energy requirements of our customers.

Under this integrated approach, each load relief opportunity is evaluated separately but in conjunction with other needs. Both traditional and new design options are evaluated and an integrated, lowest overall cost solution is chosen for implementation. The solution may include demand and supply-side solutions, new technologies, and traditional or non-traditional capacity expansion and reliability approaches.

Step 3 from Figure 4-4 above highlights the key step of identifying system expansion opportunities and identifying the specific options available to satisfy them. Under Step 3, each area substation and its corresponding load areas are evaluated to identify and prioritize the greatest near-term challenges.

The Company then builds a specific or tailored load relief plan for the pertinent load areas. This load relief plan incorporates the entire range of solutions, including usage related solutions (demand and supply), non-traditional design solutions, and traditional load relief initiatives. Elements of a conceptual plan for system expansion are illustrated in Figure 4-6. In this figure, various traditional, non-traditional, and demand/supply solutions are weighed against the criteria of cost, performance, and risk. The system expansion plan will then balance these criteria to result in an integrated and tailored solution.
for the area in need of reinforcement.

![Figure 4-6. Illustrative System Expansion Plan](image)

The range of the potential system expansion options under the tailored approach are presented in Table 4-1. They include supply and demand related options as outlined in Chapter 3 and non-traditional design options that are described later in this chapter.

**Table 4-1. Example Demand/Supply, Non-Traditional, and Traditional Load Relief Options**

<table>
<thead>
<tr>
<th>Demand/Supply Options</th>
<th>Innovative/Non-Traditional Design Options</th>
<th>Traditional Options</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Energy efficiency</td>
<td>• Virtual substations</td>
<td>• Split networks / add new substations</td>
</tr>
<tr>
<td>• Demand response</td>
<td>• Substation asset sharing</td>
<td>• Add transformers or feeders</td>
</tr>
<tr>
<td>• Distributed generation – solar,</td>
<td>• Transferrable feeder groups (switchable load transfer)</td>
<td>• Add capacitors or voltage regulators</td>
</tr>
<tr>
<td>combined heat and power (CHP),</td>
<td>• Automatic primary switching</td>
<td>• Permanent load transfers, load</td>
</tr>
<tr>
<td>and fuel cells</td>
<td>• Intelligent</td>
<td></td>
</tr>
<tr>
<td>• New transmission</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The table presents various options for system expansion, categorized into demand/supply, innovative/non-traditional, and traditional options, with corresponding costs and investment details.
Demand/Supply Options | Innovative/Non-Traditional Design Options | Traditional Options
---|---|---
underground autoloop | balancing
- System reconfiguration (add switches/ties, feeder de-bifurcation)

In summary, the expected benefits of the Company's integrated and tailored approach are as follows:

- **Reduce infrastructure cost**—Reduction and deferral of capital investments, achieved through supply and demand management and innovative designs, reduces customer bill impact.

- **Advance system design**—While maintaining or improving reliability, a directed effort to implement new, non-traditional design solutions wherever practical supports our intent to drive to a cleaner, smarter, safer, more asset utilized, and more automated electric system.

### 4.3 INNOVATIVE DESIGNS – THIRD GENERATION SYSTEM OF THE FUTURE (3G)

Central to achieving our long term goals is the availability of alternative design options that increase asset utilization, increase operational flexibility, reduce the risk of large outages, reduce street congestion, facilitate the use of new smart grid technology, reduce, avoid or defer costs, and maintain customer service and reliability. 3G design concepts are being developed and demonstrated to achieve these objectives. These design concepts include:

- Substation asset sharing,
- Transferable feeder groups,
- Distribution substations,
- Intelligent underground autoloops, and
- Low voltage migration concepts.

3G concepts can be used as system expansion alternatives, as well as alternatives to reduce the risk and improve operations. These concepts continue to develop and mature as new solutions are required and experience is gained through demonstrations and implementation.
**Substation Asset Sharing**

Our asset sharing approach achieves comparable reliability to our existing standards at lower cost than traditional infrastructure investments. In this approach, spare substation transformers in distribution area substations are shared among multiple substations. This design is conceptually illustrated in Figure 4-7.

Under a traditional second contingency (N-2) design, a typical 5-transformer area substation is designed to satisfy a peak customer demand that is equivalent to the capacity of 3 transformers with two of the transformers serving as back-up or spare transformers. In the example depicted in the figure above, two neighboring substations on the same property, identified as 'Substation A and Substation B', would be served by different transmission feeders.

Using asset sharing, the same spare or back-up transformers are shared by two nearby substations through feeder ties at primary distribution voltages, thereby eliminating the need for separate spare transformers in both area substations. Thus the N-2 design standard is shared across both substations. Since a typical area substation transformer is valued at $2.5 million, the resultant savings, due to the installation of fewer transformers and associated transmission lines, can be substantial. Since substation transformers have an extremely low failure rate, reliability is not adversely affected.

This concept will be applied for York area substation, which will be built with three transformers and two 13kV connections to East 75th Street substation. This concept is also being considered for
application in Queens, where a three transformer substation will be built with a connection to North Queens substation in order to serve increasing load. This alternative for Queens will defer major substation construction, including a switching station and two area substations.

**Transferrable Feeder Groups**

Typically our secondary networks are served from a single area substation, although a substation may serve more than one load area or secondary network. A transferrable feeder group ties feeders across two substations with an advanced, automated, normally open switch to provide possible power supply to the primary circuits from two locations. Where applicable and cost effective, a transferrable feeder group is established between existing substations to support initial incremental load growth in a neighboring area. This enables automatic load transfers between substations to provide interim load relief and defers the immediate implementation of new area substations. The transferrable feeder group requires additional fast switches and feeder cable.

Figure 4-8 illustrates the transferrable feeder group design.

![Figure 4-8. Illustrative Transferrable Feeder Group Design](image)

The transferrable feeder group provides numerous advantages, including the potential for temporary supply sources from feeders in supporting substations and lower overall risk levels. This is a promising new design but not universally applicable, as it requires additional substation and distribution level switches and cable sections. Some of our existing substations may not have the space or the capability to accommodate these new designs. At each individual substation with the potential for transferrable feeder groups, feasibility, practicality, and cost must be considered.

This concept is being considered for application in Manhattan in order to defer the construction of the 3G York station; the transfer would be implemented between Lenox Hill and Yorkville networks.
Distribution Substation (aka Virtual Substation)

The distribution substation concept builds on substation asset sharing and involves using spare transformers to normally supply a portion of a network, as well as supply back-up to a substation during a contingency. In the distribution substation concept, transformers are shared between the new station for normal supply and the existing substation for back-up supply so that demand can still be supplied if one spare transformer is switched to provide back-up to the existing substation.

Figure 4-9. Illustrative Virtual Substation Design

In a virtual substation design, the new substation is constructed with the requisite switchgear and protection equipment but without substation transformers. It is supplied via feeder ties from two nearby substations. The necessary ducting and feeders are built with the ability to supply 138kV or 345kV transmission to future substation transformers. Once demand growth is sufficient to properly utilize substation transformers, the transformers are installed and the virtual substation becomes a traditional substation. This approach lowers the overall size and cost of incremental capacity expansion, thereby lowering customer costs and improving asset utilization.

The distribution substation is an alternative to the traditional 5-transformer area substation. When demand exceeds the capacity of the distribution substation, the substation is completed to traditional or compact (1 or 2 bank) design specifications.

This concept is being considered for application in Brooklyn and Manhattan. The application in Brooklyn will be described in the section titled Integrated Solution. In the Manhattan design, a distribution switching station will be built on the West Side when the Hudson Yards area is developed. This alternative will defer major substation construction including a switching station and an area
Intelligent Underground Autoloops

In the Company’s highly reliable underground system, the distribution feeders represent the system’s point of highest vulnerability. Multiple feeder failures increase the risk of an infrequent but potentially large-scale network shutdown event. While feeder restoration times have been reduced to an all-time low as part of our effort to continuously improve operations, we are also testing higher reliability designs on these circuits. One such design is known as the intelligent underground autoloop illustrated in Figure 4-10.

The design has been effectively used in the overhead system. The overhead autoloop system integrates the electric system’s outage detection and protection equipment with automated feeder tie switches, enabling near instantaneous fault isolation and automated switching of feeders and ensuring uninterrupted power supply to the maximum number customers possible. Con Edison has been an industry leader in deploying this technology, which has enabled the Company to sustain an exceptionally high level of reliability in its overhead system.

We have developed an analogous automated 3-way switch to support an equivalent configuration in our underground system. This switch, operating in conjunction with detection and protective devices, can automatically switch among feeder options to ensure supply in the event of planned or unplanned interruption. In response to this need, Con Edison has performed a pilot implementation of this 3G approach at Randall’s Island.

This concept is also being applied as part of the capital program in the Bay Ridge and Park Slope networks. Here, the autoloop will connect a feeder from one network to a feeder in the adjacent network supplied from the same area substation, so that during a contingency, the infrastructure from the adjacent network can be used to support the contingency and reduce the risk of a large network outage. This implementation will involve one feeder from the Bay Ridge network connected through an intelligent auto-loop configuration to one feeder in the Park Slope network, using one-way underground switches.

Integrated Solutions

As multiple system needs arise, designs that satisfy these multiple needs using different technology and design tools offer integrated, least cost solutions. For example, network risk and demand growth at the substation level may need to be addressed in a given area. A common solution, like a distribution substation could be used to supply a smaller portion of a network to both reduce risk and defer substation construction. Multiple design tools and smart grid technologies can also be used to address a need. For example, underground autoloops can be implemented between sub-networks to reduce both the likelihood and severity of a large network outage.

An example of an integrated approach is shown in a potential design for the Williamsburg Network, which is one of the most risky networks for a large network outage, as quantified by the NRI metric. A distribution substation, supplied by two stand-by transformers from neighboring Water St. area substation and Plymouth St. area substations could afford the ability to supply a segmented portion of Williamsburg network. This would reduce the physical size and demand of the network, and would decrease both the likelihood and severity of a large network outage; conventional methods typically only address likelihood. Additionally, this solution would allow for future demand growth, deferring the
need for major substation construction including a switching station and two area substations. In this way, one solution meets two system needs: reduction in network NRI and providing substation level supply to accommodate demand growth.

Another example of an integrated solution is in Flushing where we are applying intelligent underground auto-loops between sub-networks in an existing large network. This design combines two concepts to reduce both the likelihood and severity of a large network outage, and provide operational flexibility. By using switches along natural boundaries in the network, a portion of the network can be isolated during a cascading network event, thereby insulating part of the network and reducing the severity of the event. The intelligent underground autoloops can be used during normal operations to isolate feeder failures and restore the un-faulted portion of the feeder. This project is being constructed as part of the Smart Grid Investment Grant; a diagram is included below:

**Figure 4-10. Illustration of Intelligent Underground Autoloop Configuration**

In the diagram above, three sub-networks are established along natural boundaries. Network feeders continue to run throughout the network, with sectionalizing switches placed at the sub-network boundaries to afford the ability to isolate each sub-network. Two intelligent underground autoloops are established using the one-way sectionalizing switches as well as three-way switches. The switches and loop configurations will be equipped with remote monitoring and control and automation. This design will improve overall operational flexibility for the network, as well as reduced likelihood and severity of a large network event in the area.
Summary of 3G Alternatives for Substations

Figure 4-11 summarizes the total capital expenditure associated with each approach.

Figure 4-11. Traditional vs. 3G Designs

New Substation Capital Expenditures
Traditional vs. 3G Design (2011-2031)
Figure 4-12 summarizes the net impact on capital expenditures by adopting the 3G design approach in lieu of the traditional designs. It results in a deferral of well over $3 billion for nearly half a decade.

**Low Voltage Migration**

The Company continues to develop 3G concepts and designs for the distribution system, including the underground low voltage mesh system. Maintaining and continuously refurbishing our vast secondary system entails significant ongoing investment commitment for the Company. 3G concepts that focus on the underground low voltage system aim to reduce this ongoing spending while maintaining reliability. The general idea behind these 3G concepts is to shift the low voltage system from one that is completely interconnected (within a network) and provides redundant infrastructure to deliver consistent service when equipment fails, to a system where customers are less interconnected with less infrastructure, featuring switches to provide flexibility in the response to equipment failures. In theory, a reduction in the interconnectedness of the low voltage mesh can reduce the risk of a cascading network event, and can lend itself to a system that requires less equipment (cables and transformers) and therefore is less costly to maintain and expand. The introduction of switching can provide flexibility to use cables and transformers that are unaffected by a failure in order to serve a target area, thereby maintaining customer reliability. Specific example projects and concepts are under development, and will be fully evaluated to determine if this general vision is feasible and will deliver the reliability and cost savings results anticipated.
4.4 DESIGN STANDARDS

The Company’s network electric system is most commonly designed to satisfy an “N minus 2” (also denoted N-2 or referred to as second contingency) standard, meaning that at various stages of electric delivery the system is designed to withstand the loss or failure of any two parallel devices. Specifically, at the distribution level we operate 64 second contingency networks; the balance of the Company’s load areas (20) are N-1 or first contingency design. This N-2 standard is generally much more rigorous than the typical electric distribution system design standard, and yields very high reliability. Even as we consistently apply this N-2 design standard to each of our distribution networks and derive excellent day-to-day reliability, the likelihood of a large-scale, prolonged network outage varies from network-to-network. This variation is the result of differences in network characteristics, including relative geographic size, number and type of components, and length and number of feeders within each network.

Con Edison has developed and utilizes sophisticated models to understand the performance behaviors of each of these networks based on their unique characteristics. The key output from these models, the Network Reliability Index (NRI), is a probabilistic measure of risk levels in each of our networks. NRI is defined as the state where four or more feeders supplying power to one local portion of a network experience failure at the same time under standard peak load operating conditions. Through the use of NRI, the Company is enhancing its design and planning criteria to ensure that infrastructure investments minimize the level of risk for all networks.

In the future, we plan to consider a combination of NRI and the resulting customer impact as measured through various reliability metrics by using probabilistic models of the system. This can help the Company evaluate the resulting customer risk levels that would result from new system designs in order to optimize spending and risk reduction.

Our objective in this area is to apply focused program investment to decrease risk on networks where the investment will have the greatest impact. While all capital investment in our networks has some impact on reducing risk, the investment in three targeted capital programs directly and most significantly reduces the risk of the loss of a network as measured by NRI:

- Removal of PILC
- Installation of sectionalizing switches on network feeders
- Increasing the number of primary distribution feeders serving a network.

While large-scale, prolonged network outages do not occur frequently, such events have tremendous impact on the customers we serve and the region as a whole. Our densely populated urban environment is critically dependent upon reliable service to power public transportation systems, elevators in high rise buildings, hospitals, and major business centers. This dependency makes reducing the risk of such an event a key objective.

Figure 4-13 illustrates the ranked NRI measures of the Company’s 6348 secondary networks. Of particular note is the annual improvement in total system NRI in each year from 2007 through 2010 and expected improvements based on planned investments through 2016. The planned investments through 2016 were determined by weighing the benefits of reducing the risk of a large-scale, prolonged network outage in our urban service territory versus the cost of implementing the programs. In this specific case, we estimate a 45% improvement across our highest risk networks based on an average annual investment of $46 million from 2011 to 2016.

Figure 4-13. NRI of Con Edison’s Second Contingency Networks

In the 2016 time-frame, the three NRI programs described above will reach points of diminishing returns. These diminishing returns result from the fact that system constraints will begin to present a limitation, as existing infrastructure (available cubicles at substations, etc.) will no longer be as available. Because the marginal benefits of these existing NRI improvement programs will begin to diminish, the effective lifecycles of these programs will begin to fade.

48 There are 64 second-contingency networks, but the new WTC network, Freedom, has no secondary grid and is in the process of being energized.
Consequently, a re-evaluation of our approach in this area will be required in 2016 to carefully weigh risk reduction benefit against the cost, and against new tools, programs, or innovations that may be available. These new tools may include modification or application of demand side management or other advanced methods. Alternative design concepts such as underground auto-loops, sub-networks, dual feeder breakers and distribution substations can also be cost effective alternative options to improving network NRI, and will be considered in the re-evaluation. We are already starting to evaluate these future options, and will do so on a continual basis.

**Long Term Design Changes**

The Company is undergoing an analysis of our long term (20- to 50-year) system design strategy with a special focus on the continued viability and fitness of our secondary networks to sustain their widespread role in the electricity delivery system in metropolitan New York. Maintaining and continuously refurbishing our vast secondary system entails significant ongoing investment commitment for the Company. New electric system and end-use technologies have the potential to require significant changes in how all electric delivery systems are utilized.

The long term system strategy initiative will focus on such topics as:

- Is widespread conversion of our secondary networks to higher distribution voltages desirable, feasible, and cost effective?
- Can the existing infrastructure support significant implementation of distributed generation, distributed electricity storage, or significant new electricity end uses?
- What is the ideal, long term network design to support New York’s energy needs?
- What are the technical and economic barriers to any widespread conversion?
- Can low voltage migration concepts be applied to reduce long term cost?

As we progress through this planning cycle, piloting new technologies, designs and systems like 3G and Smart Grid, we will gain greater insight into the feasibility of changing the fundamental design concepts that have supported and guided our infrastructure planning over the last half century. We will evaluate new information and performance of our new projects and programs to adopt the most suitable solutions. We will continue to rely on our strong research and development processes and our partnerships with industry associations and government to optimize the cost, performance, and risk of our infrastructure.

**4.5 RESEARCH AND DEVELOPMENT**

The Company’s effort to implement new system designs frequently relies on innovations in new materials, equipment, and methods. The source of these innovations is widespread, including the Company’s own operations, industry suppliers, other utilities, and various government and university sponsored research. Con Edison’s Research & Development (R&D) department plays a leadership role in facilitating integration of these new innovations.
The Company's R&D department was formed in 1970 and has a distinguished 40-year record of leading Con Edison's efforts to keep pace with the changing electric utility industry. The R&D department ensures that the Company identifies and sets research and development priorities that will improve service, reduce consumer costs, and minimize the environmental impact of delivering electric power.

Prior to industry restructuring in the late 1990s, the scope of Con Edison's overall R&D program was wider, incorporating non-transmission and distribution research in generation, emissions control, electric vehicles, and energy efficiency. In the past decade, the Company's R&D efforts have focused substantially on transmission and distribution related initiatives. Con Edison's long term vision and goals as well as regional, state, and city plans play an integral role in setting the Company's overall R&D priorities.

Con Edison's R&D efforts are commonly conducted in collaboration with other utilities, with industry groups, and other entities. In recent years we have collaborated with:

- Electric Power Research Institute
- U.S. Department of Energy
- New York State Energy Research and Development Authority
- U. S. Department of Homeland Security
- National Electric Energy Testing Research & Application Center
- Smart Grid initiatives, which includes distributed resources and energy storage

R&D programs are categorized as General R&D Support, Internal and Contractor Research, and Development and Demonstration programs. The Internal and Contractor RD&D program is further segregated into five sub programs:

- Transmission
- Distribution
- Substations and system operations
- Customer operations
- Advanced technologies

**Recent Developments**

The Company's R&D initiatives led to specific improvements in how we plan, design, construct, and operate the electric system. For example, stray voltage detection is an important customer and system safety topic and a high priority among the Company's R&D initiatives. In the past few years we have developed mobile stray voltage detection methods that have vastly improved our detection capabilities. Similarly, in collaboration with the Electric Power Research Institute, we have developed and implemented handheld stray voltage detection tools and methods.

Our asset management and control initiatives (described in detail in Chapter 5) have also been a focus
of our R&D efforts. In collaboration with the Electric Power Research Institute, we have implemented a dissolved gas in oil online analysis that has substantially improved our remote monitoring of transformer conditions. Similarly, our underground autoloop switch and fast switch (discussed above) are the result of the Company’s other R&D efforts. Our long term system monitoring and control initiative is a collaboration with multiple partners and will lead to our Secure Interoperable Open Smart Grid Demonstration vision.

Some other recent R&D initiatives include:

- Network Arc Fault Detection Monitoring
- Conservation Voltage Optimization Modeling
- Incipient Fault Location on Underground Feeder Monitoring
- Operator Situational Awareness Tool
- Business Intelligence Technology System for Call Center

### 4.6 SIGNPOSTS

We have identified two signposts that will trigger the review and adjustment of our design strategies at any point during implementation of this plan. These signposts include:

- **Growth in electricity demand**—3G deployment can occur more rapidly in areas of system expansion or major construction. We will continuously monitor growth in our service territory and adjust implementation plans as necessary.

- **Technology innovation**—Significant breakthroughs in materials, communications, computing, energy storage, and other energy-related technologies could significantly alter the scope and pace of 3G implementation and the wider role and function of the Con Edison network.

### 4.7 SUMMARY

Due to the many unique characteristics of the Con Edison system, system design will always play a prominent role in our efforts to make continuous improvement in the cost, performance, and risk characteristics of our system. Design requirements need to be re-assessed in light of new analytic techniques that point to the ability to deliver value and reliability for customers. We believe an integrated and tailored approach to system design will lead to solutions that minimize costs while maximizing the performance and risk benefits of new investments.

As noted in Figure 4-1, growing customer demand requires us to expand system capacity. System expansion investments comprise 42% of the total capital expenditures in this twenty year plan. Our updated system expansion planning process focuses on integrating demand and supply side management, with innovative or 3G designs, with traditional capacity expansion investments.

The cost to replace aging equipment on our system is a major source of required capital investment. These costs will point to continual required increases in revenue requirement over an extended horizon in the absence of steps to offset their impact. Such potential measures include regulatory and tax reform, improvements in Company operating effectiveness, and changes in the ratemaking process including accelerated depreciation.
To maximize the impact of our R&D efforts, we have focused on identification and development of system design innovations. This focus has led to 3G innovations such as asset sharing, transferrable feeder groups, and virtual substations, all of which will have significant and measurable positive impact on customer rates throughout the life of this plan.

Our integrated and tailored system design approach and innovations support our efforts to sustain high reliability levels. Our tailored design philosophy drives continuous improvement of NRI on our network. While this chapter of the Electric System Long Range Plan focused on our system design initiatives, the next chapter of this report will focus on our asset management and control initiatives.
5.0 IMPROVING ASSET MANAGEMENT & CONTROL

5.1 INTRODUCTION TO ASSET MANAGEMENT

An effective asset management program should provide structure for maintenance and asset replacement activities. Our asset management programs and processes evaluate the performance, cost and risk characteristics of the components that, collectively, make up our electric transmission and distribution system. We use various methods and tools to monitor, analyze, and control our assets to produce our best estimate of optimal performance of our electrical components, asset classes and overall system. The information we capture and analyze provides the basis to evaluate and compare the performance across various components or asset classes to assure that we are targeting our programs properly and therefore optimizing the money we spend on asset maintenance, repair, and replacement.

As we have added more sophisticated monitoring on our components we have been able to continue our progress from time-based maintenance to real-time and condition-based maintenance. By gathering and analyzing data from in-field sensors we are better able to understand performance trends of specific asset classes. Additional monitoring may allow us to alter maintenance cycles, improve the design of specific assets, and predict and prevent component failures.

Our electric system consists of over 727 miles of underground transmission cable and 438 miles of overhead transmission lines supported by 1,212 transmission towers. This transmission system supplies power to 39 transmission substations and 62 area distribution substations. The distribution system is composed of 64 underground networks which are supplied by 2,270 primary distribution cable circuits and 27,000 underground transformers. These assets are connected through 540,000 secondary cable mains that make-up the meshed grid. In addition, there are 49,800 transformers in the overhead distribution system, which are mounted on 209,300 poles. These assets, among others, represent billions of dollars of capital investment, and many are starting to reach the end of their expected life.

We expect to spend an average of $500 million per year (in real 2011 dollars) to maintain our existing electric infrastructure and an additional $520 million to add new infrastructure to meet demand growth. As a significant portion of our annual capital expenditure is dedicated to our existing infrastructure, our optimization of these expenditures for maintenance, repair, and replacement is critically important to meet electricity needs safely, reliability, and cost effectively.

We address examples of the programs discussed above in the various sections that follow. We have organized our discussion by Distribution, Substations and Transmission and will end with a discussion about our Smart Grid project, which pilots the application of the newest monitoring and customer interface technologies.
5.1.1 Background on Categories of Capital Expenditure

A little less than half of the Company's capital expenditure over the next twenty years will be dedicated towards maintaining our high levels of reliability and replacing our existing infrastructure to ensure the safe operation of our assets (Figure 5-1). This portfolio of investment is consistent with spending at other large U.S. utilities. A sound asset management approach is necessary to optimize our maintain-repair-replace decisions on each of our asset classes.

Figure 5-1. CECONY 20-Year Capital Spending Summary

Expenditures in the 'Reliability' and 'Replacement' categories constitute maintaining the Company's current levels of reliability and replacing the Company's existing equipment and cable, either due to failure or after inspection. These investment categories account for 31-55%\(^49\) of annual capital expenditures in any particular year and 40% of the total 20-year plan. Annual expenditure ranges from $440 million to $640 million. Much of the equipment replacement investment is part of continuing programs that are more fully described in the following subsections of this report.

As we expand our infrastructure and invest $10.94 billion over the next 20 years to meet growing customer energy requirements, we will leverage some of the same efficient practices we employ in managing our existing assets to implement better designs, make better purchase decisions, and better manage our inventory.

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\(^{49}\) Excluding the annual 'Common' expenditure
Figure 5-2 shows total capital expenditures categorized by major functional group. This functional breakdown is consistent with how we design and implement our asset management programs.

The system expansion category, which contains the largest projected capital expenditures of the investment plan, is primarily a function of transmission and area substation construction patterns coincident with customer demand growth. Substation investment levels peak between 2029 and 2030 to account for new substation investments required to handle increases in customer demand in certain networks. Application of innovative 3G designs to six substations are expected to lower substation expenditure for the 20-year period by $3.6 billion as compared to what traditional substation designs would have cost.

The ‘Reliability’ and ‘Replacement’ categories represent a significant amount of our forecasted capital spend over the planning horizon. These expenditures are categorized as repair, maintenance, or replacement work done on our transmission and distribution cables, equipment, and structures. Within the transmission and distribution systems, underground network distribution expenditures represent the majority of the costs, as these costs are proportional to the density and scale of assets in our 64 second-contingency underground networks.

The ‘Common’ budget includes expenditures on projects shared across the Company, such as common information technology projects and facilities projects. This should account for a relatively small portion of the overall planned expenditures. The ‘Interference’ expenditures, which include expenditures on work done in conjunction with public improvement projects, and the ‘Other’ expenditures, which include expenditures on all other work not belonging to any of the aforementioned categories, represent the smallest portions of our total spending, though the funding in these categories could be tied to the annual funding level of key projects. For example, funding for the Work Management System for Electric Operations is included in the ‘Other’ category.
In the following pages we discuss major recent initiatives, near-term plans, and the long-term direction of the Company's approach to managing the assets that comprise our transmission system, area substations, and distribution system.

5.1.2 Overview of Equipment Replacement Strategies

Like virtually all U.S. utilities, we face the challenges of maintaining a very large infrastructure of equipment, cable and structures. The Company's capital maintenance expenditures replace equipment after failure and programmatically upgrade or replace system components prior to failure or obsolescence.

Primary distribution cable, network transformers, and secondary cable are the largest classes of assets installed in the electric delivery system. In general, the Company's expenditures for cable and equipment are more consistent year to year than system expansion expenditures. This is because long-term programs have been developed to address the repair, maintenance, and replacement of various asset classes. In contrast, system expansion expenditure is driven by relatively variable local usage patterns and economic conditions.

Over the last few years, efforts have led to improvements in two vital and interrelated areas of analysis: component analysis and electric system analysis. Improved component analysis allows us to now identify potential problems within an asset category such as manufacturing flaws or life cycle fatigue. These problems may pose possible challenges to performance and hence operating risk. Our efforts to improve electric component analysis acknowledge the reality that because the electric system operates as a network of electrical devices (i.e., components) – each with different performance characteristics – system reliability is the product of the performance of each of the components in the system. The Company's electric system analysis monitors these relationships and performance among components as they are configured in the electric system.

The Company has realized, and will continue to realize, significant benefits from its targeted efforts to identify and implement the best mix of replacements, maintenance, and repair. The types of benefits realized include:

- **Reduction in replacement volume**—Equivalent or improved electric system reliability at a reduced level of replacement investment due to monitoring that can pinpoint small problems so that they are addressed before they become more widespread.
- **Reduction in replacement unit cost**—Reduced unit replacement costs as more replacement events occur according to schedule and prior to failure. Replacement of failed components is generally more expensive as it disrupts planned work, causes overtime labor costs, and typically takes longer to accomplish.
- **Reduction in operations and maintenance cost**—While we expect to realize increases in some operations and maintenance categories due to the broader deployment of monitoring technologies, we expect lower overall maintenance requirements due to the replacement of obsolete components with improved materials and designs.
- **Reduction of system and public safety risks**—Prevention of emergency failures, which have unpredictable consequences.

Improvements to our asset management practices have resulted in better decision-making capabilities and processes. Our practices have been enabled by enhanced monitoring of assets' condition and
improved data collection systems, and advanced decision-analysis and modeling capabilities. We continue to define preferred design standards, data collection and analysis needs, and maintenance practices incorporating the best available industry knowledge and technology.

5.2 DISTRIBUTION ASSET MANAGEMENT

5.2.1 Optimization Strategy

Electric Operations continues to refine and extend an improved prioritization process that was adopted in early 2009. Since its implementation, this approach has resulted in the quantification of benefits from targeted investment to capital programs. Supporting cost-benefit relationships continue to provide an effective means of gauging program effectiveness across investments and at varying levels of investment.

Cost-benefit curves as well as performance targets continue to be used to determine optimal program investment levels. Calculated benefits of a program’s contribution to risk reduction and achievement of strategic objectives are used to prioritize programs and to dictate program investment across programs. Our engineering planning organizations utilize a tiering process to evaluate relative ranking of benefits, to identify and rank programs that yield different levels of benefit for dollars spent, and to determine the extent to which a program should be expanded or contracted.

In support of both the 2011 and 2012 Capital Budget Process, 19 electric distribution capital reliability programs have been targeted for the development of cost-benefit analyses. These programs total approximately $268 million and represent over 97% of the total 2011 System Relief and Reliability planned expenditures. In addition to representing a significant proportion of the 2011 and 2012 budgets, these programs were selected based on a net benefit index. The net benefit index is comprised of a combination of the Risk Priority Number (RPN) and Corporate Strategic Objectives (CSO). The RPN metrics, supplied through the Enterprise Risk Management committee, and CSO categories provide high level guidelines to assist in the prioritization of programs. For each program these guidelines quantify the program’s relative impact on the likelihood, severity, and controllability of specific system events.

Additionally, an overall portfolio analysis of the electric distribution programs completed under this initiative is currently being undertaken and refined. The results of this analysis, coupled with engineering review and judgment, should quantify the distribution of capital expenditures across targeted programs to ensure that the benefits from capital investments yield the greatest overall benefit for the dollars spent.
Table 5-1 lists the programs currently being evaluated. We discuss a few of these programs in detail as examples to illustrate how they benefit overall system performance, cost, and risk.

Table 5-1. Current Scope of the Asset Optimization Initiative

<table>
<thead>
<tr>
<th>Program</th>
<th>Current Capital Plan</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>2011 Budget ($000)</td>
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<tr>
<td>Cable Crossing</td>
<td>$6,800</td>
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<td>Osmose (C Truss)</td>
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<tr>
<td>Autoloop Reliability</td>
<td>$2,807</td>
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<tr>
<td>Aerial Cable Replacement</td>
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<td>#4, #6 Self Supporting Wire</td>
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<td>OH Feeder Sectionalizing</td>
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<tr>
<td>Secondary Open Mains</td>
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<tr>
<td>PILC Replacement</td>
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<td>Vented Manhole Cover</td>
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<td>Vented Service Box Cover</td>
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<td>4 kV UG Reliability</td>
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<td>RMS 3rd Generation</td>
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<td>PTO Sensors/DGOA (2 programs)</td>
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<td>Sectionalizing Switches</td>
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<td>Streetlight Service Reliability (ISOs)</td>
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</tr>
</tbody>
</table>
Optimization Program Examples: Paper-Insulated Lead Covered Cable Replacement and Underground Sectionalizing Switch Installation

As an example, we compare the effectiveness of two of the programs listed in Table 5-1, Paper-Insulated Lead Covered (PILC) Cable replacement and the installation of underground sectionalizing switches. We have analyzed the cost and performance of each of these programs and produced cost versus benefit curves to facilitate comparison and to determine investment levels across various programs.

The PILC cable replacement program encompasses our ongoing effort to replace sections of primary underground 13kV and 27kV PILC cable. PILC cable is lead jacketed and uses oil-impregnated paper as its insulating medium. We no longer install PILC cable; we are now using Ethylene propylene rubber (EPR) insulated cable. EPR cable is more environmentally friendly since it contains neither oil nor a lead jacket. It also provides higher reliability, due to its superior mechanical and insulating properties.

Our effort to replace PILC cable has been underway for over a decade. It has had the operations benefit of reducing the failure rate of our feeders and therefore the risk of a large-scale, prolonged network outage, especially in high customer usage periods (e.g. hot days). The cost to replace a section of PILC cable, typically several hundred feet long, is approximately $20,000 and provides measurable reliability improvement. These activities have contributed to a declining number of cable failures and their associated outages.

While replacing PILC cable reduces the incidence of feeder failures, many other programs also positively impact feeder and network reliability. One such program is the installation of underground sectionalizing switches at strategic points on our 13kV and 27kV network feeders. Sectionalizing switches are typically installed either very near the area substation on two separate parallel outbound cables, which essentially create two feeders out of one, or by placing a switch midway along the single feeder path, which provides quicker restoration of half of the feeder when a component fails. Both of these approaches help us to restore the feeder to service quickly and therefore reduce the probability of cascading feeder failures and a prolonged, large-scale outage in the network. Installation of a sectionalizing switch with SCADA control costs approximately $260,000 and provides a measurable network reliability benefit.

PILC cable replacement and the installation of underground sectionalizing switches each provide a measurable reliability benefit. Our asset prioritization process measures and compares marginal reliability improvement, using NRI, at various levels of investment. We use this comparison to analyze the incremental benefit and cost of each program and identify the most efficient investment across a mix of reliability programs. Figures 5-3 and 5-4 compare NRI improvements at recent cumulative investment levels for replacement of PILC cable and installation of underground sectionalizing switches.
Figure 5-3. NRI Improvement from PILC Replacement

Percent Increase in Years to NRI

vs. Cumulative Targeted PILC Replacement Costs
Analysis of these two figures reveals that the same 21% increase in NRI that is achieved from $130 million in PILC cable replacement can be achieved by spending approximately $7.6 million for underground sectionalizing switch installations. Thus, equivalent NRI improvement can be realized by installing sectionalizing switches at approximately 1/20th of the investment required for PILC cable replacement. Comprehensive analysis across all major programs enables the Company to adjust its reliability programs periodically to ensure the effective investment of capital.

While this analysis would lead one to believe we should only install switches and not replace PILC cable to gain benefits in NRI, the density of our underground system in some areas inhibits our ability to install underground sectionalizing switches on a large scale. Replacing sections of cable typically does not require new infrastructure as it can be installed in the existing conduit. Also, installing switches optimizes capital spend in selected networks, while replacing PILC cable addresses the root problem. Thus, both engineering and construction feasibility must be taken into account when considering individual reliability improvement projects. Therefore, a mix of projects typically yields the best practical overall reliability benefit.

Cost-benefit curves can also be used to identify the optimal levels of spending within specific component replacement programs. Figure 5-4 shows a “flattening” of the benefit curve, which signals diminishing incremental impact of increased spending on underground sectionalizing switches. This suggests a logical upper limit to the benefits from increased investment.
5.2.2 Management of Major Asset Classes

As noted above, the Company’s asset management initiative is designed to facilitate the optimization of ‘maintain-repair-replace’ decisions among all asset classes and asset-related programs. Asset condition, which is a function of many factors including manufacturer, usage, and age, impacts system performance and risk characteristics. The following subsections of this chapter explain how we incorporate component condition and current performance into our system analyses.

Low Voltage Network Cables

Our secondary cable networks, composed of approximately 70,000 miles of underground low voltage cable, constitute our largest asset class. Our network grids are comprised of more than a half million secondary conductor sections, or “mains”. A secondary main ranges from one hundred to several hundred feet in length. Together, 540,000 of these interconnected mains make up our low voltage network grids. By design, these systems of secondary mains provide excellent reliability to the customers served by our networks. The grids are built to provide multiple paths from the source transformers to the customers through secondary cables. All of the cables in these grids are located underground and housed mainly in concrete conduits which provide a relatively ‘safe’ environment for the bulk of the cable. Due primarily to the protected environment of these cables, the average age of the asset class is just over forty years. The connection points for these cables are housed in manholes, vaults and service boxes. These underground structures may be subject to a harsher environment including water, mud, salt and other materials that wash in from street level.

From these grids we feed millions of service cables that provide electricity directly to homes and buildings, and an additional several hundred thousand smaller service cables that provide electricity to streetlights. A service to a home, building or streetlight is typically no more than one hundred feet.

At an annual expenditure of approximately $150 million, we replace about 5,200 sections of mains each year, which is just about 1% of the total population of mains. Damaged sections are replaced after failure or inspection. The cause for replacement is due mainly to compromised insulation. We replace approximately 6,000 services per year to homes and buildings and 5,100 services to streetlights. This replacement level of services requires approximately $50 million of capital investment annually.

Unlike our network distribution and transmission transformers, and many of our medium and high voltage switches and cables, our low voltage secondary cables are neither equipped with monitoring nor communications technology. As such, we rely on our inspection programs and known failures to trigger replacement activities. The overwhelming size of this asset class and its relative inaccessibility underground, present significant challenges to systematically optimize replacement activities.

The redundancy of our secondary low voltage grids, while contributing to the very high reliability of the low voltage networks, makes it difficult to identify failures as they occur. A cable may no longer be carrying power, but the power normally flowing through it automatically reroutes to another section to serve the customer. This hides the presence of low voltage cables that are no longer functioning, and as a result, failed sections can go unnoticed on our system. A breech in insulation, however, does not automatically cause a known problem. The power in the conductor will still flow and serve the customer so long as that cable’s insulation is in a relatively dry environment and not touching another conductor directly or any other metallic or conductive material.
Low voltage cables are located underground, in manholes and in ducts (conduit), making sections of cable difficult to access and expensive to repair. The predominant failure season is during winter snow storms. During these storms, salt is spread to melt the snow and it washes into our underground structures, sometimes reaching the conductors of the cable through damaged insulation. Salt water is very conductive and can cause short circuits. The number of failures during this season is magnified and the access problems normally encountered become exacerbated with the presence of snow and ice. While winter can be a particularly difficult time to address this system, we experience failures, and make replacements, all year round.

The failure of a low voltage cable may cause a localized service interruption or outage. Because there is no monitoring on these cables, when an underground network customer experiences a partial or full service outage, typically the first notification we receive is when they call our customer service representatives to inquire about restoration. While we have developed computer algorithms to give us an early warning for a potentially wider-scale customer outage in our network, for individual outages we rely on the customers call to alert us to the service interruption.

The failure of a low voltage cable may also contribute to public safety hazards like stray voltage or a smoke condition in a manhole that could cause carbon monoxide to migrate to an adjacent dwelling. Public and employee safety is important to us. Recent trends indicate that public safety conditions caused by our secondary cable assets are decreasing due to a number of programs and initiatives we employ.

Even as we add advanced modeling to these systems, we are held back by a lack of monitoring to validate these models and assess real-time conditions. Equipping this system with monitoring has been extremely challenging in the past due to the need for hundreds of thousands of monitors (potentially millions if employed for each customer) that must be able to function in and communicate from an underground environment, and robust computer modeling systems to analyze the data. We have managed our secondary cable system through technology changes in materials and designs, inspections, and a ‘replace after failure’ mode.

To harden our low voltage grids against risk of insulation breakdown, since 2001 we have been installing a low-voltage cable that incorporates dual-layer insulation. This insulation is physically tougher than past materials and provides superior protection against mechanical and environmental damage. It has a fire resistant, low-smoke outer jacket that produces less harmful fumes if the cable is ever involved in a fire. This new cable benefits both reliability and system safety.

To reduce risk from potential smoke conditions, we have replaced all of our solid manhole covers with vented ones so that we recognize these hazards more quickly, mitigate the severity of explosive gasses and keep potentially harmful smoke out of customers’ dwellings. We are moving to a similar program with our smaller service boxes. In addition we seal the ducts that feed a customer’s service point in our structures and in the customer’s premise (on new installations) to prevent carbon monoxide from entering customer dwellings.

To reduce instances of stray voltage emanating from our low voltage cable infrastructure, our research and development department partnered with a technology company to manufacture a mobile stray voltage detector as discussed in chapter four. We now scan our entire underground system once per month and find very low levels of stray voltage (down to one volt). When we find an incidence of stray voltage we eliminate the condition through isolation, replacement, and/or repair. These scans are the best targeting effort we have employed to date on this asset class to find and replace sections with damaged insulation before they become larger issues.
At the end of 2009 we completed the first five year inspection program of underground structures. Through this program, we inspect the condition of every manhole and service box in our network underground system, and as a result of this program and our findings we have replaced a number of low voltage cables, and made completely new connections to existing cables in our structures when needed. Essentially this renews the system in a local area. We are developing a secondary risk model that will assist in ranking our underground structures. This will allow us to migrate away from the five year inspection program that treats each asset equally, and allow us to prioritize our inspection, repair, and replacement efforts on this vast system. The use of a risk model coupled with the advanced technology of the mobile stray voltage detection will optimize our efforts to improve underground secondary performance.

Figure 5-5 depicts the annual number of manhole events since 2006.

Since this is one of our most cost intensive asset classes and one of the last on our system with little detailed modeling, nor effective real-time monitoring, we set out to explore various options. For the past decade or so, we have been working to develop and deploy secondary models of our network systems. We have been limited by the scarcity of monitoring data and a need for tremendous resources to code the many cables in our network systems into an accurate connected grid in a computer model. However, we are on the verge of deploying effective secondary models that will help us more efficiently plan for our secondary network grid systems.
We currently have a number of research projects underway to identify impending secondary cable failures so they can be repaired before they develop into safety hazards such as stray voltage or manhole events. These projects are developing the technology to recognize the electrical signatures created by defects in secondary cables using sensors installed on primary feeders, in network protector relays on secondary cables. Initial results indicate that these electrical signatures are detectable in advance of cable failures but more work needs to be done to implement a practical system.

In addition, new monitoring and control technologies such as an automated metering infrastructure (AMI) and Smart Grid implementation, discussed later in this chapter, are introducing opportunities to greatly influence how we manage this asset class in the future. Data points at the customer level provided by AMI would give our engineers the information necessary to perform customer demand analysis across our secondary mains and services. It would yield the data necessary to validate our models in real time and provide intelligence on local secondary disturbances signaling timely operational response for repair. As programming and computer technologies improve, data collection and modeling could become so robust that it could be employed operationally to give our operators eyes into the secondary cable grids they have not had before. This access to and understanding of information would lead to a revolution in how we design, reinforce and manage our low voltage cable assets.

We are reviewing the potential to migrate away from asset intensive secondary networks while maintaining comparable levels of reliability for the customer. As a first step in this effort, we are installing “spot networks” for large customers at lower demand thresholds than in the past. A spot network is an electrically isolated high voltage service that feeds directly from the Company’s primary system to a customer. Voltage is then transformed at the customer site to provide low voltage (120/208V or 277/480V).

In addition to reducing the risks associated with secondary cable systems, the implementation of spot networks reduces the reliance on the adjacent secondary network, enabling incremental load growth from other customers without expansion of secondary network capacity.

Over the course of the plan, initiatives such as distributed generation integrated as dispersed supply sources in the network, could result in additional opportunities to migrate away from the secondary low voltage grids.

**Network Transformers**

The secondary network system contains over 26,000 transformers, which are characterized by an average age of 19 years. The transformers are filled with oil for insulation and cooling. The reliability of these transformers is critical to overall network performance, and if a transformer ruptures and fails, it can present a public safety issue.

To improve the performance of our underground network transformer population, we have implemented a remote monitoring system (RMS) and combined it with enhanced routines for monitoring, inspection, and maintenance. Enhanced remote monitoring systems provide information about the health of the transformer and enables preventive replacement before failure.
Our remote monitoring system has been improving for decades. The first generation of this system reported only electric loading and several status or “trouble” indicators. A second generation of technology added voltage monitoring. Over time, the transmitter technology migrated from solid state to microprocessors. Current third-generation measurement technology has the added capability to monitor transformer pressure, temperature, and oil level readings (PTO), and near real-time reporting over existing power lines, enabling online, remote diagnostics. As of December 2011, we had deployed 13,000 PTO sensors throughout the system. All new transformers are equipped with the latest generation of RMS upon installation. Continued PTO deployment will enable transition from a time-based to a condition-based transformer protocol for managing our transformers.

We analyze all transformer failures that cause a feeder to open automatically at our Distribution Engineering Equipment Analysis Center (DEEAC). In-service failure rates for network transformers have decreased due to an aggressive program of testing our transformers through dissolved-gas-in-oil-analysis (DGOA). We have made further improvements through transformer design changes in the transformer tank precipitated by recent DEEAC findings.

Figure 5-6 portrays multi-year in-service failures for underground network transformers. Failures have decreased 72% since 2005. Reduction in transformer failure rates results in a significant reduction in overall operating and safety risk and improves feeder reliability. Over the course of the plan, as we learn even more about these assets, we will continue to seek ways to employ new technologies and devices to improve the performance of this asset.

Figure 5-6. Underground Network Transformer Failure Trends
Primary Distribution Cables

Our primary distribution cables supply power, through over 2,270 feeder circuits, from our Area or Unit Substations to distribution transformers that further reduce the voltage to the level intended to meet the customer's demand. Our distribution system consists of over 20,000 miles of primary circuits operating at 4kV, 13kV, 27kV or 33kV with an average age of 24 years. The medium voltage cables used on our primary distribution feeders employ a shielded design with either oil impregnated paper (Paper Insulated Lead Covered, PILC, cable), cross-linked Polyethylene (XLP) or Ethylene Propylene Rubber (EPR) insulations. The PILC cable was installed from the 1920s through the mid 1980s with XLP cable installed from 1970 through the early 1990s. The Company, since 1995, has only installed EPR cable on its primary distribution feeders.

The table below shows the three principal primary distribution cable types by insulation class, reported population and failure rate.

<table>
<thead>
<tr>
<th>Cable Type</th>
<th>Population in Miles</th>
<th>Population in Cable Sections</th>
<th>Percent of System</th>
<th>Failure Rate (Failure/Mile of Cable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PILC</td>
<td>3,182</td>
<td>22,500</td>
<td>15.8%</td>
<td>0.0079</td>
</tr>
<tr>
<td>XLP</td>
<td>6,469</td>
<td>45,700</td>
<td>32.0%</td>
<td>0.0045</td>
</tr>
<tr>
<td>EPR</td>
<td>10,525</td>
<td>74,382</td>
<td>52.2%</td>
<td>0.0030</td>
</tr>
</tbody>
</table>

The 20,000 miles of primary distribution cable is connected through 113,000 medium voltage splices. These splices consist of: lead-sleeve splices that connect PILC cable to PILC cable, solid dielectric splices that connect XLP and EPR cable, and transition or stop-joints that connect XLP/EPR cable to PILC cable. The solid dielectric splices make up almost 75% of the splices used on the primary distribution system and they are the most reliable of all splices.

Figure 5-7 shows the relative failure rate trends of the three types of primary distribution cable and two types of splices. The cables show a very stable performance over time with the EPR cable clearly out performing both the XLP and PILC cables. The chart also demonstrates the superior performance of the solid dielectric splice against the performance of the predominant type of transition, or stop-joint, splice. Maintenance programs have been developed, and implemented, to reduce these transition splice failures.
We currently manage our primary cable assets through a variety of system modeling, preventive maintenance, and cable replacement programs. Each is described below:

- A load-flow program has been developed to model the entire primary and secondary distribution systems. The primary distribution models are used to detect overloaded cable sections and plan for the subsequent feeder reinforcement work.

- We employ a preventative maintenance program on our primary feeder asset class through the use of high-voltage withstand tests (HiPot Test). The test applies high voltage to a de-energized feeder in an attempt to “weed” out components with incipient faults that could fail during the high-load summer period.

- A PILC cable replacement program was implemented in the late 1990s to remove high failure rate components from the primary distribution system. The program targets PILC cable and high failure rate transition splices that have been known to compromise the system during the high-load summer period.
Figure 5-8 shows the feeder component failures over the past five years. The data shows that our asset management programs have, in part, resulted in a 21% reduction in primary feeder component failures.

Figure 5-8. Feeder Component Failure Trends
During the next two decades we will improve the performance of our primary distribution cable assets through:

- The development of a more refined network model that will better represent the actual power flows on the primary and secondary distribution systems. A more accurate representation of the load flow will allow us to better assess the need for system reinforcement.

- Refinement of methods to identify "incipient" faults on primary cables so that they can be addressed before they develop into feeder failures. Our work to date shows that primary feeders exhibit short duration events days or weeks before actually failing. We are developing algorithms to allow our substation relays to detect and identify such events to allow us to direct our diagnostic efforts toward those feeders to repair any defects and improve feeder reliability.

- The continued development of a cable rating program (for both primary and secondary voltage-class cable) that more accurately models the thermal environment and works directly with the load-flow program. These enhancements will also allow us to better assess the need for system reinforcement.

- Development and implementation of an enhanced PILC cable replacement program to better target program investments.

- Development of better designs for medium and low voltage cables through our work with our principal cable supplier and EPRI (Electric Power Research Institute). We are developing the next generation of cable insulation through "nano" technologies and enhanced material design. The new cable will be smaller in diameter, more flexible and carry a higher thermal rating.

- Continued our work at our state-of-the-art Cable Center of Excellence facility. Among the projects under development are improved diagnostics for our primary feeders including infra-red scanning to identify defective components operating at higher than normal temperatures, partial discharge technology to identify defects in operating primary feeders and splices and arc fault detection technology to identify arcing faults on secondary cables which can contribute to manhole events and customer outages.

**Overhead Distribution System**

Our overhead distribution system is substantial in its own right. It supplies power to 877,000 customers, or approximately 26% of our total customer base. The system, which operates at 4kV, 13kV, 27kV, and 33kV, consists of 209,300 poles, 49,800 pole mounted transformers and 27,500 miles of overhead wires.

Over the plan horizon, we'll continue to implement capital and maintenance programs needed to maintain reliability, employing the asset optimization process discussed above. Some of the specific programs for the overhead system include:

**#4 and #6 Copper Wire and Self-supporting Aerial Cable (SSC) Replacement**

The protective outer jacketed layers on some older vintage overhead conductors and the insulation of self-supporting aerial cable are weathered and degraded to a level that has a negative impact on system reliability. The Company has an ongoing program to replace the existing deteriorated #4 and
#6 copper wire and self-supporting aerial cable with new conductors, poles and associated hardware installed to the Company’s latest construction standards and specifications. These upgrades will reduce the frequency and duration of customer interruptions. The investments in this program are prioritized through engineering analysis to achieve the greatest reliability improvements.

**Wood Pole Inspection and Treatment**

The integrity of the 209,300 poles on the overhead system is critical to system performance. Pole inspections are performed to ensure the reliability of installed poles and the safety of the public. As part of the Company’s asset management strategy, the majority of the inspected poles (approximately 80%) are subsequently treated in order to preserve the pole’s acceptable working condition and thereby extend pole life. Inspection and treatment involves “sounding” the pole, taking bore samples, internal treatment, and the installation of a wrap around the base of the pole. In addition to these inspection and treatment programs, some poles are restored to full strength and functionality by way of C-Trussing, which reinforces the base of the pole by installing a metal “C” shaped truss along its side. The installation of C-trusses defers the need to replace the pole, resulting in savings. The Company’s multi-faceted pole maintenance program ensures that our investments on this asset class are optimized.

**Line Clearance (Tree Trimming) Program**

Trees limbs and branches coming in contact with overhead wires represent a sizable threat to overhead system reliability, causing approximately 11% of non-major storm related interruptions on the overhead system. In 2007, in an effort to improve reliability, the company developed an enhanced line clearance program encompassing appropriate risk prevention and mitigation strategies. By increasing clearances between tree limbs and the overhead conductors, targeting the work to those feeders most impacted by tree-related interruptions, and addressing unhealthy trees along the utility right-of-way, the program has proven effective. A major component of the program is an aggressive communications strategy focusing on information sharing and customer outreach.

This constantly evolving program has already had a significant impact on customer reliability, particularly during adverse weather. From the advent of this program through the end of 2010, the number of non-network customer interruptions due to tree contacts has decreased by 33%. Over the course of the 20-year plan, we will continue to adjust the program, leveraging benchmarking efforts and lessons learned to ensure we optimize the impact of this critical program.

**Installation of 4kV and 13kV Open Wire Automatic Sectionalizing Switches**

The deployment of new, technologically advanced devices over the 20-year planning horizon will allow us to efficiently meet reliability objectives on our overhead system. We plan to install automatic sectionalizing switches throughout the 4kV overhead system. These automatic switches, with microprocessor technologies, provide superior coordination with other protective devices and higher fault interrupting capabilities than earlier vintage switches. They will also reduce service interruptions as they are capable of isolating faulted sections in a more targeted fashion (i.e. providing single-phase isolation of faults as opposed to three-phase isolation of existing switches). Over the next 20-years, we’ll also implement a program to provide improved fault isolating capabilities on our 13kV autoloops. The installation of additional switches with enhance interrupting capabilities will yield reliability gains similar to those stated above. These automatic switches will be fitted with Supervisory Control and Data Acquisition (SCADA) equipment to remotely monitor and control these devices.
5.3 SUBSTATION ASSET MANAGEMENT

During the past decade, the electric utility industry has been moving from period-based maintenance practices to condition-based maintenance practices. We have been an early and aggressive adopter of condition-based asset maintenance. With regard to our Substation assets, we have focused on the following:

- Substation transformers
- High voltage circuit breakers
- Low voltage circuit breakers
- Capacitor banks

The following subsections of this chapter summarize some of the Company’s recent advances in asset management methods for the largest classes of assets.

Substation Transformers

Substation transformers are used in area substations to transform power from transmission voltages (138 kV and 345kV) to distribution voltages (13kV, 27kV, and 33kV). Our system includes 421 substation transformers with an average age of 29.5 years. Thirty-seven percent of these transformers are over 40 years old. Like network distribution transformers, the substation transformers are filled with oil to provide insulation and cooling.

As can be seen in Figure 5-9, for substation transformers there is no discernable rising trend of failure with age. Since age is not a reliable indicator of transformer health, alternate measures must be utilized.
While most transformer failures have a modest localized cost with no safety implications, they can result in unplanned outages and do have the potential to become major events. Major events occur with low frequency but could result in significant environmental or personnel safety consequences.

Over the past thirty-two years, the failure rate of our substation transformer fleet has been about 0.75%. To prevent their failure, high-risk transformers are identified and either repaired or replaced. Our internally-developed methodology employs an algorithm that considers the transformer condition parameters listed below.

- Transformer manufacturer and other nameplate information
- Dissolved gas in oil history
- Oil quality
- Furan analysis
- Environmental condition (oil leaks)
- Type of load tap changer (LTC)
- Controls and wiring issues
- Operating history
• Maintenance history
• Loading history
• Teardown inspection results from similar transformers
• Availability of spare parts

Each condition parameter is assigned a score, ranging from zero to five, which is then multiplied by a weighting factor that takes into account the importance of each condition parameter in determining the overall health of the transformer. For example, as part of the assessment, we externally inspect each transformer to determine its general condition and identify environmental concerns (oil leaks). A rating of 0-5 is assigned for the environmental condition of each transformer and recorded in a master file.

The algorithm produces a transformer health index on a score that is normalized to 100. Approximately 216 transformers have been evaluated using this program. We will evaluate and prioritize the remainder of our transformers to develop a complete assessment of the health of our transformer fleet.

To further enhance this effort, we have an ongoing research and development collaboration with Electric Power Research Institute (EPRI) to develop a Predictive Reliability and Risk Assessment program for our transformer fleet. The Predictive Reliability and Risk Assessment program will assess transformers and assign individual risk rankings, which can be used for transformer life-cycle asset management. This program will combine transformer health and impact of failure to determine the overall evaluation.

Replacement Philosophy

The decision to replace a transformer is based upon its risk of failure, the potential consequence of failure, economic constraints, and substation construction and maintenance schedules. Before we decide to replace a transformer, we consider the costs and probable outcome of transformer repair.

High Voltage (345 and 138kV) Circuit Breakers

We have 458 high voltage circuit breakers on our transmission system. These circuit breakers provide proper isolation and protection when a fault occurs on a cable. Historically, the maintenance plan for circuit breakers was based primarily on time and to a lesser extent the number of operations of a particular circuit breaker. This was due to the limited ability to economically collect and maintain condition based data for individual circuit breakers. Recent advances in data collection methodologies as well as newly-developed software analysis tools have enabled us to adopt condition-based circuit breaker maintenance programs.

The move to condition-based maintenance for circuit breakers allows for better allocation of maintenance resources directed at the circuit breakers most in need of attention. There are three different approaches to determine the need for maintenance or replacement of a circuit breaker or class of circuit breakers. The first approach uses in-service monitoring and out-of-service diagnostic tools. The testing (in-service or out-of-service) provides critical data to determine the health of a circuit breaker. The second approach uses a ranking software program developed by EPRI to rank circuit breaker performance. This software uses data from various sources to calculate a health index for
each circuit breaker. The data includes maintenance and operation history, past history of similar breakers as well as risk factors such as system position, safety and environmental. The third approach uses data collected during the teardown, overhaul, or inspection of circuit breakers to predict the condition of other circuit breakers of the same type. Together, these three methods allow a team of subject matter experts to determine when a circuit breaker is most likely to need major maintenance to keep it in an acceptable operating condition. When a circuit breaker requires major maintenance it is then evaluated to determine whether the breaker should undergo targeted maintenance to resolve a specific problem, a complete overhaul to return the breaker to a like-new condition, or replacement. The decision to overhaul or replace is based on various factors including cost, future maintenance costs, environmental, safety, and obsolescence.

The annual cost savings estimated from our effort to optimize circuit breaker asset lives is approximately $3 million in capital and $700 thousand in O&M.

Medium Voltage (13, 27 and 33 kV) Circuit Breakers

The CECONY electric distribution system has 3,491 medium voltage (13kV/27kV/33kV) circuit breakers. These circuit breakers provide proper isolation and protection when a fault occurs on a cable. We recently reviewed our approach to circuit breaker maintenance together with historic performance data to determine if improvements could be made to the scope and frequency for our preventive maintenance activities. As a result of this review, we are implementing several major changes, outlined below:

- The frequency of visits for inspecting vacuum and sulfur-hexafluoride (SF6) medium voltage circuit breakers was extended from six years to ten years.
- The frequency for inspection of circuit breakers installed in conjunction with our metal-enclosed capacitor banks was extended from one year to ten years to align with the requirements for similar feeder breakers.
- The insulation resistance testing of control wiring during circuit breaker preventive maintenance inspections is no longer required. The control circuits are now monitored with ground detection relays, which are more effective.
- The proper maintenance of these circuit breakers is being outlined in an assistive video we are currently developing. The use of this video is expected to improve the quality of maintenance as well as help increase efficiency, thereby lowering costs.

We will continue to monitor the performance of all medium voltage circuit breakers to affirm these changes positively impact performance. We believe that the changes to medium voltage breaker maintenance activities will result in a total savings of approximately $3.6 million dollars over the life of the ELRP.

Outdoor (13 and 27 kV) Capacitor Banks

The CECONY electric distribution system has 125 outdoor 13/27 kV capacitor banks. A recent review of our maintenance procedures and performance data for standard 13/27 kV capacitor banks led to changes to our maintenance and testing cycle. We developed a targeted maintenance program assuring that the frequency of maintenance inspection is closely correlated to the risk of equipment failure.
The annual maintenance plan includes: infrared inspection of the capacitor bank while in service; visual inspection of all fuses, capacitor cans, and cap bank area; and inspection of the protective fencing. These activities were chosen based on a review of past capacitor bank outages. Performing annual inspections that concentrate on the items that most often cause outages is expected to reduce outages. However, some inspections conducted on an annual basis proved to be more cost effective on an elongated cycle of five or ten years based on risk profiles.

These changes to our capacitor bank maintenance routine should result in total savings of approximately $4.6 million over the planning horizon. Going forward the performance of the capacitor banks will be monitored to confirm that the new targeted maintenance keeps the capacitor banks in an acceptable condition. If required the maintenance plan will be altered based on the results.

5.4 TRANSMISSION ASSET MANAGEMENT

Con Edison’s transmission infrastructure consists of conductors that carry transmission voltage from generating sources or transmission lines to substations. Con Edison owns or jointly owns 438 circuit miles of overhead lines operating at 138, 230, 345 and 500 kV. The Company’s overhead transmission system is comprised of 1,212 towers that support “open-wire” type conductors.

We also operate the largest underground transmission system in the United States: 742 circuit miles of CE-owned and jointly-owned underground cable operating at 69, 138 and 345 kV. The Company’s underground transmission feeders are either oil or solid-dielectric insulated. Oil-insulated cables are typically installed in steel pipes, whereas solid dielectric cables are typically installed in fiberglass reinforced epoxy conduit banks housed in concrete.


Our pipe-type transmission system was one of the first of its kind and today it is one of the oldest and largest in the world. Despite its age, system performance is exemplary. Only 55 electrical cable failures were experienced for the period 1955-2010. Furthermore, the rate of failure has generally not increased with cables’ age, as evidenced by Figure 5-10.
Transmission Dielectric System Leaks

The system’s steel pipes which house the transmission feeders are an important focus of our asset management activities, as they are essential in the reliability of the system. Several programs have been implemented to protect these pipes from corrosion or other damage, including:

- A state-of-the-art cathodic protection system
- A system of drain-bonds for mitigation of DC stray current from subways
- A program to refurbish pipes within manholes that cannot be protected cathodically
- A coating refurbishment program to address areas of coating disbondment
- An active participation in a program to minimize contractor damage (code 753)

As a result of these efforts, these pipes are expected to continue to provide reliable service as part of the underground electric transmission system. In addition, we are developing plans to re-use these pipes as conduits for future solid dielectric cable installations.
When leaks do occur, we employ a sophisticated leak detection system with the ability to detect leaks at rates of one gallon per hour on selected feeders. The online leak detection system continuously performs a dynamic mass balance everywhere along the cable system. Leak detection is accomplished when there is a deficit between the predicted fluid entering the cable system and the corresponding measured quantity.

**Dynamic Feeder Ratings of Transmission Feeders**

The current-carrying capacity of transmission feeders, or feeder rating, is determined based upon a number of factors, including conductor size and the temperature and moisture of the earth surrounding the feeder. Traditionally, earth temperature and moisture data used in the rating process were taken as constants. Dynamic Feeder Rating (DFR) Systems use real time data to improve the accuracy of these ratings. For example, the temperature of the earth varies throughout the year, peaking in the late summer. By measuring and analyzing data on a real time basis, more accurate and often increased ratings are determined, providing operators with actionable data to manage the system.

Through the use of real-time data and analytical modeling, DFR Systems allow us to maximize asset utilization. Over the course of the plan, we intend to implement similar initiatives to leverage information through monitoring and control.

**Solid Dielectric Cables**

Con Edison will continue to expand the use of solid dielectric cables to install new transmission facilities or when replacing existing transmission feeders. Although oil filled pipe-type cable and solid dielectric cables have comparable installation costs, solid dielectric cables are preferred whenever possible because they offer two distinct advantages over high pressure pipe type cables.

First, they eliminate the environmental issues associated with oil leaks from pipe-type cables. In addition, they require less maintenance than do pipe-type cables because they don’t require associated systems such as pressurizing, circulating and cooling plants, pressure alarms, motor operated valves, and cathodic protection systems.

In addition, solid dielectric cables are generally easier to install and repair because they do not require the extensive pressurization procedures that are necessary before oil filled systems can be placed in or be restored to service.

To further increase the use of these cables, Con Edison is undertaking a research project to evaluate the feasibility of re-using not only existing piping as conduits for new solid dielectric cables but existing manholes to house their new splices. There are various technical challenges associated with this project having to do with the expansion and contraction of these cables as their load cycles. Resolving these issues will greatly reduce costs, most of which is presently associated with trenching, duct and manhole installation.
5.5  ENHANCING MONITORING AND CONTROL OF THE GRID

5.5.1 Electric System Modeling, Monitoring, and Control

A fundamental characteristic of electric transmission and distribution systems is that they deliver electric power through a network of mutually interdependent transmission and distribution components or assets. Consequently, and especially because of the sheer size of these systems, the Company's electric system replacement and maintenance strategies as outlined above must embody more than merely a component focus; rather, they must be based on how these electric system components operate in concert with one another.

Consequently, the Company has a number of initiatives that are related to improving how we model, monitor, and control our electric system. These initiatives are designed to reduce operating costs, minimize (or optimize) investment requirements, maintain system reliability, improve safety, and reduce risks.

At the transmission, sub-transmission, substation, and primary distribution stages of delivery the Company has detailed, real-time operating and long-term system planning models. Although these resources are subject to continuous innovation, we have made significant progress on improving our modeling capabilities related to the Company's primary feeders and low voltage networks.

We continue to refine the reliability models of our primary distribution feeders by incorporating more detailed information on component failure rates. In 2008 the Company began an initiative to improve secondary network modeling by utilizing existing company modeling programs, map records, and telemetry along with new data validation methods to better simulate load flows across the low voltage cables of secondary network grids. This more accurate secondary modeling will help us to understand the needs of our low voltage networks, will improve primary and transformer load modeling, and enable better prioritization of our asset-related activities on the Company’s secondary networks. These efforts include improved modeling of the capabilities of our low voltage cables through more accurate thermal models of the underground environment, as well as detailed studies of aged cables removed from our system. This modeling will also be enhanced by leveraging customer use information available from future advanced metering infrastructure (AMI), which will provide detailed data at the customer level, as it is deployed.

This enhanced secondary modeling, as it is implemented in the next several years, has the potential to:

- Prioritize and reduce investment requirements in the secondary network so that the investment resources are targeted at the most critical secondary system replacement needs,
- Reduce the unit costs of some of our repair and replacement activities by performing more of them under normal, rather than emergency (and thus potentially more costly), conditions,
- Lower the overall risk in the system by improved modeling of real-time operations.
The effectiveness of our modeling capabilities are closely related to the quality and accuracy of the data and information we have about how the electric system actually performs under a variety of loading conditions. Consequently, we are making continuous efforts to develop and implement cost-effective system monitoring to improve this information base. For example, all of the Company’s network transformers are monitored for loading and approximately half of them are also equipped to monitor oil level, internal pressure, voltage, and temperature conditions. This expanded transformer monitoring will be deployed to all network transformers by 2018. Another example is our expansion of the existing monitoring of our primary distribution feeders to include the ability to detect incipient faults, which adds another dimension to the measurement of asset health. While these monitoring resources play a key role in our real-time system operation and maintenance procedures, they also have an important role in supporting and improving our system modeling.

While AMI application within our system has slowed dramatically due to regulatory feedback, one of the Company’s existing AMI initiatives is expected to provide a new level of system monitoring and performance data to improve the quality and accuracy of the Company’s modeling and support efforts to further realize the benefits outlined above. This AMI initiative will provide the first near-real-time or real-time customer-level loading data that can be used to support our network models.

5.5.2 AMI and Smart Grid

In an effort to evaluate the Smart Grid concept, the Company developed network- and customer-focused pilot implementations of various Smart Grid technologies. The Company’s Long Island City (LIC) Pilot, which was announced in July 2009 and was completed in 2011, was the Company’s most comprehensive effort yet.

The Smart Grid demonstration in Long Island City was recently completed with the installation of 1500 smart meters, 300 home area networks, transformer and network protector monitoring and control, electric vehicle charging, feeder reconfiguration and a common communication system. Supporting data management for the control center and engineering applications were also implemented. Work continues on integrating smart meter data into the Meter Data Management System, and is expected to be complete in 2012.
Figure 5-11 illustrates the key elements of the Company’s Smart Grid implementation.

Figure 5-11. Elements of a Smart Grid

Smart Grid
Smart Grid puts information and communication technology into electricity generation, delivery, and consumption, making systems cleaner, safer, and more reliable and efficient.

Smart Building Technology
Including web portals and in-home displays will eventually allow customers to track their energy use and give them the tools to change their energy-using habits, including the ability to remotely control appliances.

Intelligent Underground Systems
Use sophisticated communication technology to monitor, isolate, and correct problems and improve reliability.

Greener Energy Sources
Are more readily integrated into the smart distribution grid.

Smart Meters
Gather information about customers’ energy use so customers can use electricity more efficiently, and the meters may enable the utility to identify system problems.

Plug-In Electric Cars
Can connect to the grid to charge and, one day, may even provide power from their battery packs when the cars are not in use.

Customer Energy Generators
Enhance system reliability.

The Company anticipates the following benefits from the LIC Smart Grid initiative, including:

- Proof of concept for new wireless monitoring and control technologies
- New data collection opportunities on distributed supply and customer demand patterns
- Secondary model validation from the increased demand and power flow data
- Expanded system monitoring
- Further implementation of 3G applications
- Proof of concept associated with the ability to support the interconnection to new renewable power supplies

5.5.3 Stimulus Grants

Investment Grants

The Company filed grant applications for stimulus funding in June 2009 with the U.S. Department of Energy. Our Smart Grid Stimulus Award was approved and announced on October 25, 2009. Grant funding includes distribution initiatives led by Con Edison and transmission initiatives led by NYISO.
Table 5-3 summarizes the specific scope and value of the Smart Grid project.

**Table 5-3. Elements of CECONY’s Smart Grid Project**

<table>
<thead>
<tr>
<th>Application Focus</th>
<th>Project Components</th>
<th>Total Cost</th>
<th>DOE Funding Requested</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>Dynamic Modeling &amp; Visualization</td>
<td>$19.0</td>
<td>$9.5</td>
</tr>
<tr>
<td></td>
<td>UG Sectionalizing Switches</td>
<td>$40.0</td>
<td>$20.0</td>
</tr>
<tr>
<td></td>
<td>4 kV Grid Modernization</td>
<td>$21.0</td>
<td>$10.5</td>
</tr>
<tr>
<td></td>
<td>OH Sectionalizing Switches</td>
<td>$45.8</td>
<td>$22.9</td>
</tr>
<tr>
<td></td>
<td>Remote Monitoring System Upgrade</td>
<td>$47.5</td>
<td>$23.8</td>
</tr>
<tr>
<td></td>
<td>High Tension Monitoring</td>
<td>$2.0</td>
<td>$1.0</td>
</tr>
<tr>
<td></td>
<td>UG Intelligent Automatic Loop</td>
<td>$71.6</td>
<td>$35.8</td>
</tr>
<tr>
<td></td>
<td>Vault Data Acquisition System (VDAS)/DG Interconnection</td>
<td>$6.5</td>
<td>$3.2</td>
</tr>
<tr>
<td>Sub-Total</td>
<td></td>
<td><strong>$253.4</strong></td>
<td><strong>$126.7</strong></td>
</tr>
<tr>
<td>Transmission</td>
<td>CECONY Phasor Measurement Units</td>
<td>$6.4</td>
<td>$3.2</td>
</tr>
</tbody>
</table>

The project includes Distribution Automation, Dynamic Modeling and Simulation, and Energy Efficiency initiatives which address Con Edison’s ongoing challenges of maintaining reliability of service and satisfying the increasing demand on resources. By implementing advanced system capabilities like rapid restoration and grid reconfiguration, achieving efficient delivery through system losses reduction, enhancing data visualization, and integrating smart grid technologies, the project attains new capabilities for the Company’s electric system and its customers.

The Distribution Automation component includes strategic programs that put Con Edison’s electric distribution system on the road to the future. The programs include:

- Installing intelligent SCADA-controlled sectionalizing switches
- Expanding secure monitoring and communication systems
- Implementing advanced computational intelligence for automated system restoration; and
- Expanding our distribution smart grid

The Dynamic Modeling and Simulation component integrates data from diverse systems to generate predict and visualize information on the secondary grid through dynamic modeling and developing a distribution simulator. This will enable enhanced visualization of information and improve our modeling capabilities.
The System Efficiency component accommodates distributed generation, increases energy efficiency and reduces system losses. The major project objectives are:

- Expand distribution automation to advance self-healing grid operations
- Provide greater visibility and expand automation and control of one of the world’s most complex distribution systems
- Establish cyber-secure and scalable communication platforms
- Augment decision support systems with sensor feedback to provide improvements to the predictive models that identify, isolate and rectify system vulnerabilities
- Expand monitoring and control elements necessary to adapt to dynamic conditions of the service area

**Secure Interoperable Open Smart Grid Demonstration Project**

We anticipate that the continual evolution of information and telecommunication technologies will reduce the overall cost and improve the performance of our electric system. Our long-term objective is to develop a smarter grid that will capture the full benefits of improved and additional monitoring, modeling and control. The long-term end state is to enable targeted demand response by the integration of customer-owned demand response resources into our grid operations. This initiative will consolidate CECONY’s Smart Grid initiatives under a single, integrated master information system and control technology:

Some of the long-term objectives of the Secure Interoperable Open Smart Grid Demonstration Project are to:

- Manage and adapt to new distributed generation supplies such as solar and EV recharging
- Integrate control of building management systems and other demand response resources, such as distributed energy storage through third-party service providers
- Minimize or eliminate distribution system stress by enabling targeted demand response
- Migrate to preventive maintenance as enabled by improved data and information systems
- Maintain cyber security over T&D network operations and energy usage

We will leverage the American Recovery and Reinvestment Act (ARRA) Smart Grid funding as practical and admissible to support the Secure Interoperable Open Smart Grid Demonstration Project. We will be receiving an additional $45 million in funding and working with a number of companies from different industries, such as the manufacturing, utility, and higher education industries.
Figure 5-12 introduces our three phase approach to Smart Grid.

**Figure 5-12. Smart Grid Implementation Plan**

<table>
<thead>
<tr>
<th>Phase I: 1-5 Years</th>
<th>Phase II: 5-10 years</th>
<th>Phase III: 10-20 Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Develop and evaluate monitoring, control, modeling, and visualization technologies</td>
<td>Establish widespread system control and automation under AMI and the Secure Interoperable Open Smart Grid Demonstration Project</td>
<td>Integrate innovative technologies to enhance end use and minimize T&amp;D investments</td>
</tr>
</tbody>
</table>

Phase I of this effort consists of a series of key technology ‘proof of concept’ implementations, including:

- Advanced secondary remote monitoring supported by AMI
- Distribution primary automation and control
- 3G /asset sharing applications
- Home/building automation for all classes of customers
- Integration of distributed generation (DG) technologies
- Comprehensive secondary modeling, analysis, and visualization

Phase II of the Company’s Smart Grid Strategy will build on the results of Phase I and incorporates widespread implementation of Smart Grid technologies, including:

- Secondary monitoring and control
- Distributed Generation
- Emerging materials and energy storage technologies
- Home and building automation to improve efficiency and control
- Integrated control

Phase III of the Company’s Smart Grid Strategy will build on the results of Phase II and may include:

- Implementation of new materials and storage technologies, including high temperature super conductors and batteries
- Enablement and promotion of new end-use technologies (PHEVs, EVs).
5.6 SUMMARY

Approximately 45% of the total ELRP capital expenditure is allocated to the Company's asset management and equipment replacement. Therefore, developing the optimal approach to management of component maintenance, repair, and replacement decisions is critically important to the Company and its customers. An additional 47% of capital investment, for system build out to meet customer demand, can also be impacted via better system design to optimize asset utilization.

Our asset management initiatives encompass all asset classes involved in every stage of delivery. Over the life of this plan, they will produce about $600 million in avoided capital expenditures by identifying optimal maintenance cycles, determining replacement strategies, and analyzing the system performance, cost, and risk trade-offs.

Enhanced monitoring and control will produce long-term improvements in system performance and lower costs. Increasingly granular asset health and performance information will ultimately enable us to optimize future system investment. We are actively pursuing a variety of Smart Grid pilot initiatives to improve the monitoring and control of our system. Should we see promising results from these pilots we will explore opportunities for extending Smart Grid applications throughout our service territory.

5.7 SIGNPOSTS

Our asset management initiatives are actively managed in all areas of the Company and they are continuously monitored, analyzed, and improved to ensure their effectiveness. While the effectiveness of individual programs is continuously monitored, our overall asset management strategy and approach will also be monitored, evaluated, and adapted as needed. Some of the signposts that we will monitor (some internal and some external) to make our assessment of the overall asset management strategy will include:

- **Realized Efficiency**—Our overall goal is to minimize total system investment while sustaining our world-class reliability performance and minimizing system risk. While we may not observe that our total system replacement/reinvestment spending levels decline in nominal terms, we do expect to see continuous improvement in the relative efficiency of our investments (e.g. nominal improvement in NRI per dollar investment) as we continuously improve our investment targeting strategies.

- **Realized NRI**—Our asset management initiatives are highly focused on sustaining reliability and reducing risk at minimal practical cost. We have seen and continue to expect that the network-level and system-wide NRI will improve and this improvement should be directly attributable to specific decisions made from asset management processes. We also believe that the accuracy of forecasted NRI and actual results will improve over time.

- **Asset Management Strategies and Resulting Performance**—Our asset management strategies will optimize our repair-maintain-replace decisions as a result of more selective component replacement and improved condition-based maintenance actions. We will actively monitor and assess the effects of our decisions to ensure that performance objectives are met.

- **Regulatory Approval**—Some of our replacement, inspection and maintenance practices and policies are subject to regulatory approval or directed by regulatory mandates. We will
actively monitor these requirements and adapt our strategies and plans accordingly.

- **Availability of External Funding Sources**—The national and regional energy industry is the focus of substantial government attention and, more recently, active investment incentives and government funding. Several of our major monitoring and control and renewable portfolio-related investments are dependent on these external incentives and funding and we will monitor these initiatives to seek to maximize the benefits achievable.
6.0 SUMMARY

6.1 CHALLENGES

Planning for this more responsible energy future begins with understanding our internal and external challenges.

Internal Challenges

In the next twenty years, variables that will challenge and redefine the basic assumptions of electricity delivery, from economic drivers to technological innovations and customers’ increasing ability to control their usage, will change the landscape upon which Con Edison and other utilities operate. As we have done for the past 150 years, we will continue our commitment to provide reliable electric service at an affordable cost to customers for years to come. Reliability and affordability: these are the two guiding principles of our long range plan. We hold ourselves as responsible for the quality of service we provide as we do for the financial impact it has on our customers.

To address internal challenges, we need to adapt our planning, design, and operational practices. As in the past, we will continue to build and maintain the necessary electric delivery infrastructure. To achieve excellence in this pursuit, we will introduce and implement innovative approaches as compared to what were previously standard practices. We will establish improved planning processes that leverage quantitative measures to optimize our project and program investment portfolio, and further to continuously prioritize and incorporate feedback into that process. We will continue to reevaluate our traditional design standards to find lesser-cost solutions to meeting our customers’ growing and changing needs, with designs that will need to provide greater flexibility than ever before. To reduce our overall cost structure, we need to continue to reevaluate our operational practices and continue to enhance our cost management practices. We will incorporate probabilistic analyses into our infrastructure designs to increase the asset utilization in our infrastructure. In short, we will plan for change, implement design and operational practices that support those changes, and meet the changing needs of our customers, while providing safe, reliable service in a cost effective manner.

We are as proud to serve the New York metropolitan area as we are to be one of its citizens; being one of its oldest citizens, however, has its impacts. We operate some of the largest and most complex infrastructure systems in New York’s metropolitan area. To meet our customers’ needs, we utilize a tremendous amount of assets, whether wires, manholes, or poles, and after they are built, they must be maintained. A significant amount of our annual capital investment portfolio over the next twenty years will be dedicated to the renewal and replacement of this infrastructure. Our focus will be on maintaining a sound infrastructure at the lowest cost possible. Past industry practices have focused on a time-based approach to asset management and to increase our efficiency we are using analysis to adopt a condition-based approach. To further reduce the impact of these assets on our customers’ bills, we need to focus on increasing our asset utilization.

We will need to implement both traditional and innovative design solutions. Advances in communications, such as Smart Grid technologies, will continue to give us greater visibility into the status of our transmission and distribution systems. We need to leverage this in the future by installing more monitoring and control equipment that will allow us to increase system automation and the accuracy of our predictive system models, and will help us to focus on those system components that need the most attention. A core principle of Con Edison’s system design approach is the use of tailored solutions to fulfill these requirements. Tailored solutions apply targeted demand and supply
side management programs, advanced technologies and innovative designs, as well as traditional infrastructure investments to specific load areas. Our tailored approach will result in the application of solutions where they can provide maximum benefit for our customers.

Excellence demands that these challenges are addressed with a keen awareness of the impact we have on our customers; for this reason, our standing responsibility to provide safe and reliable service to our customers will be balanced by efforts to mitigate bill and rate increases. Reliable and safe service is an expectation of our customers, and we consider it a mighty challenge to balance these expectations with lower and reduced costs, but it is a balance we will aggressively pursue. By implementing aggressive demand side management programs, new designs, switching to condition based asset management by installing more monitoring and control, and driving efficiencies in the business by implementing programs like enhanced work and cost management practices, we can lower our cost structure. Addressing these challenges will give customers the same levels of reliability they have today with less risk of large scale prolonged disruptions to natural flows of everyday business and life, whether they be as a result of transformer failures or instances of stray voltage. To our customers, outages mean lost business and financial impact, not to mention public safety concerns in high-rise and densely populated areas reliant upon elevators, subways, and other electrically supplied public services.

**External Challenges**

Our delivery charges constitute about 30% of our typical residential bill. The supply rate constitutes about 41% of an average residential bill. Since customers purchase their electricity supply from a range of competitive suppliers, the supply rate is largely outside of Con Edison's purview. As much as practical, Con Edison's electricity supply for its full service customers is developed from the least cost options available to the Company. The supply portion of our customer bill is directly related to the market price of electricity, which is itself highly dependent on regional fuel supply costs, fuel mix, environmental costs, and the supply/demand balance. Many of these core cost factors have been characterized by significant volatility in recent years. In addition, a supply tax, representing approximately 3% of an average residential customer’s bill, is imposed on each customer. The tax is based on a sales tax rate applied against purchased supply and a general receipts tax applied against Con Edison total revenues.

More than 25% of the total bill and 45% of the delivery portion of the bill is due to taxes and fees (see Section 2.3.3). These are largely out of the control of the Company yet contribute to the upward pressure on bills. We will continue our dialogue with government and tax authorities to ensure full transparency of all components of the bill and to work toward minimizing upward pressure on our customers’ bills. We have consistently advocated on behalf of our customers that New York’s state and local governments reform utility taxation because of the regressive nature of utility taxes. In the current economic climate where large business users of electricity are aggressively seeking to reduce their energy costs, high taxes and fees imposed on a utility drive the cost of energy up, providing an incentive to explore other options. Loss of business customers would leave Con Edison's residential customers to bear even higher costs to the detriment of New York’s economic viability. Taxes for CECONY, and therefore for our customers, are principally comprised of four components: property taxes, income taxes, revenue taxes, and sales taxes charged to customers. For the purposes of this plan, the tax rates were held steady for the duration of the plan horizon. However, the assessed value of property taxes, the largest contributor to the tax portion of our customer's bill, increases over time with new capital infrastructure expenditures. The customer bill also includes fees collected for governmental entities. The System Benefits Charge and Renewable Portfolio Standard surcharge are
mandated fees that finance energy efficiency and renewable portfolio programs administered by the New York State Energy Research and Development Authority (NYSERDA). The System Benefits Charge funds programs that have been determined by the Public Service Commission to be inadequately addressed by New York’s competitive energy markets. In addition, the 18-a assessment fee is imposed by the New York State Legislature for the support of the State’s General Fund. Our plan reflects the current expiration dates of these fees, with the System Benefits Charge expiring in 2016, and the 18-a assessment fee due to expire in 2014.

It should be expected that this challenge will continue during the 20-year term of this plan, i.e., there will be a continuing tendency to raise taxes through the utility bill and use the utility bill to fund worthy social-environmental goals that would be more appropriately funded from general taxation revenues.

6.2 CONTINUALLY IDENTIFYING OPPORTUNITIES TO REDUCE COSTS

Savings Achieved through Planning Process

Of the total 20-year ELRP capital expenditure illustrated in Figure 5-1 of Chapter 5, 40% is allocated to the Company’s asset management and equipment replacement, while 42% is used for system expansion to meet customer demand. This means that almost half of the Company’s spending is required for maintaining the safety and reliability of the existing electric infrastructure. It is therefore critically important to us that we optimize the management of component maintenance, repair, and replacement decisions to minimize cost impact to our customers.

Cost considerations are a major part of our planning process, and we’re continuously looking for ways to do things better. Our strategy is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, and ensure employee and public safety. Through the efforts of this long range planning process, we have been able to identify $7.5 billion in estimated savings ($3.3 billion from the 2010 plan and $4.2 billion from this plan) over the twenty year horizon, which would be only partially offset by $1.8 billion to support newly projected system expansion needs in particular areas.

Major savings have come from our efforts in managing system expansion, using tailored and innovative approaches to system design and better managing our existing assets (explained in greater detail in Chapters 4 and 5). Managing system expansion allows for the deferral of capital-intensive infrastructure investments, which has substantial cost savings. Demand Side Management initiatives assure that we have the capacity necessary to support growing customer demand and support our ability to provide safe, reliable, and reasonably priced service that is environmentally responsible. The Company intends to continue to develop and improve its integrated and tailored approach to meet customer demand. We have looked to 3G designs as an innovative approach to meet capacity needs at the least possible cost. 3G provides not only less asset intensive designs but also the capability to optimize on the asset utilization of what we currently own, allowing us to defer some of the large capital expenditures that would be required by implementing a traditional design. This is another example of how the Company strives to meet the needs of the customers in a more cost-effective way. The total savings realized from innovative 3G designs is $3.6 billion over the 20-year planning horizon.
The Company has also made great strides in determining ways in which we can better perform our asset management and equipment replacement programs. We are moving from time-based to condition-based maintenance, which drives towards better cost and performance management, and we have and will continue to develop planning tools like enhanced work management systems to help accomplish this. The Company has in fact realized, and will continue to realize, significant benefits from its targeted efforts to identify and implement the best mix of replacements, maintenance, and repair. The total savings realized from these targeted efforts is $600 million.

As we expand and invest in our infrastructure over the next 20 years to meet the expected growing customer energy requirements, we will continue to manage our existing assets to implement better designs, make better purchase decisions, and better manage our inventory so that we can provide maximum benefit for our customers at the most reasonable price possible.

**Con Edison Supported Reforms to Reduce Customer Costs**

There are a number of governmental and policy reforms that the Company could pursue to reduce its electricity costs for its customers. They can be divided into: (1) tax reforms; (2) financing reforms; (3) supply reforms; (4) ratemaking reforms; (5) operational reforms; (6) customer service reforms; and (7) social policy reforms. Examples of each are set forth below.

**Tax Reforms**

- **Property Taxes**—The property tax classification system in New York City is outmoded and should be examined from the point of view of modernizing the tax system and achieving a more equitable approach to property taxation. These taxes are beyond the Company's direct control. By reducing these taxes, we can reduce our customers' bills, thereby increasing the affordability of the services we provide.

**Financing reforms**

Con Edison customers would benefit from low cost financing. For example, at one time, Con Edison had access to tax-exempt financing from the New York State Environmental and Research Development Authority (NYSERDA). Savings from tax-exempt debt are available to lower electric rates. Con Edison has been unable to issue tax-exempt debt since 1994. Among other things, Con Edison's bond rating is not at a level that would make the Company eligible for the NYSERDA program without costly and difficult to get credit support.

- **Capital Recovery**—Faster capital recovery of utility investments, while potentially increasing bills in the short terms, would reduce long term rate pressure, and over time lead to lower bills.

**Supply reforms**

- **ISO Pricing Reforms**—Investigate changes required to lower energy costs through initiatives intended to improve market efficiency such as the NYISO’s broader regional markets initiative.
- **Upstate Hydropower**—Seek geographically equitable distribution of State-owned hydroelectric resources. New York’s upstate hydroelectric resources are a state resource and the benefits of these resources should be more equitably spread throughout the State.
Ratemaking reforms

- **Performance-Based Ratemaking (PBR)**—The Public Service Commission’s implementation of PBR could align investors’ and customers’ interests in more efficient operations by modifying rate plan frameworks to provide utilities with stronger incentives for achieving efficiencies.

Operational reforms

- **Equipment Inspection Program**—Currently-required equipment inspection cycles may be capable of reform to achieve operating goals more efficiently (e.g., extension of required inspection cycle from 5 years to 10 years may be feasible and would significantly reduce maintenance costs).

Customer service reforms

- **Customer Service Centers**—Customer service centers were once common in many industries, but they have been phased out. The current requirement for availability of face-to-face customer service in each borough or county may be an unnecessary cost.
- **Call Center Staffing**—With the growth in other methods of communication, call center requirements can be reviewed from the standpoint of cost, e.g., reduction in the service hours for non-emergency calls and requirements for toll-free telephone service.

Social policy reforms

- **Low-Income Customer Rate Program**—Seek additional governmental funding of the low-income program so as to reduce or eliminate subsidy by other customers.
- **Madison Square Garden (MSG) Discount**—Eliminate subsidy of MSG by other customers that is being provided pursuant to special interest legislation.
- **Joint Bidding**—Expand joint bidding on interference work (currently applicable only in limited areas of Manhattan) that would make public improvement work more efficient and less costly.

6.3 CUSTOMER BILLS

As a Company, our goal is to provide the best option for our customers’ energy service needs, and our customers have come to expect the highest service reliability from us. We want to be easy to work with, effective in our services, and an important supporting player in the local economy and our customers’ lives. We want to enable the next evolution in energy delivery infrastructure and operate a safe, sustainable and reliable system. We also will continue to plan, design, and manage our system in a cost effective manner, and to seek ways to advance the performance of our people and our infrastructure.

We will continue to do everything we can to keep our costs down and to help customers control their energy costs while maintaining the highest levels of service reliability and system safety. The delivery rate covers costs to build and maintain our transmission, substation, and distribution assets as well as to maintain and operate the customer billing and other operations platforms to service customers. Other components of the bill include supply costs and taxes and fees. Over the past twenty years we were able to keep delivery rates in-line with inflation, and we will try to keep our costs down as much
as possible in the future.

From our efforts to implement the plan initiatives, we project a bill increase slightly above the rate of inflation. Planned investment levels along with projected increases in the cost of supply will increase a typical New York City residential customers’ monthly bill from $81.40 today in 2011 to $88.15 in 2031, an average compound annual growth rate (CAGR) of 0.4%. Our delivery charges, representing the cost of transporting energy from the point of supply to the Con Edison system to the customer, constitute less than a third of the typical residential bill; the remaining two thirds are attributable to costs of supply and costs to cover taxes and fees imposed by various government agencies and electricity suppliers.

We strive to minimize customer bills and have outlined in this document several programs and initiatives to manage our infrastructure costs as well as to work directly with customers to manage their energy expenditures. We will continue to make every effort to keep our transmission and distribution rates down, nevertheless, as described above, market and policy forces outside of our control will continue to affect our customers’ bills.

As discussed throughout this plan, we see the objective to better manage costs to our customers as an imposing challenge, but one which we intend to pursue and achieve. We will continue to explore and implement ways to reduce rate and bill costs for our customers and operate our system in the most cost efficient way possible, while delivering the benefits of safe and reliable electric service to customers in an innovative and environmentally responsible way.

6.4 SUMMARY OF THE CHANGES FROM THE 2010 PLAN

The Electric System Long Range Plan provides us with a roadmap for our electric system for the next twenty years. This plan guides us toward a responsible energy future for our customers, with safe, reliable energy sources that are both environmentally responsible and affordably priced. Building that future will require that we meet the challenges described in this plan by maintaining the electric infrastructure necessary for the transmission and distribution of electricity and evaluating the role of advanced metering and smart grid technologies in modernizing the electric grid. This comprehensive plan is a holistic way to effectively integrate our electric system infrastructure plans with non-infrastructure related elements of our business, such as demand side solutions and renewable resources. The plan considers ongoing improved asset management for existing infrastructure and a tailored approach to design that includes alternatives and innovative technologies. The plan also provides a framework that links short-term projects and long-term actions to our goals and objectives.

To develop the original plan’s forecasts for electricity demand and a supply outlook, we made assumptions regarding potential environmental and regulatory requirements, economic trends, and included possible technological advances to develop three forecasts for potential customer demand. In the 2010 plan and in this 2011 update, we used the Plan Case demand forecast to develop the infrastructure projects and programs in this plan. The difference in the growth of peak demand is summarized in the 20-year average annual growth rate, which in last year’s plan was 1.7% per year from 2010 to 2030, and in this year’s plan is 1.14% per year. In this regard it is worth noting that even though the overall system growth rate is lower in this year’s plan, there was an increase of $1.8 billion required over the 20 years to accommodate specific growth areas. Our plan was developed under considerable uncertainty (i.e., technological, regulatory, and economic) and as a result we identified key signposts that we will monitor and use to adapt our plan as changes occur. This first long range plan is intended to be a living document, with assumptions that will be refined in future versions, as
this 2011 update demonstrates.

Throughout development of the original plan, we measured our performance by showing the expected benefits of our projects over the long-term, managed our costs to keep in mind rate and customer bill impacts, and sought to maintain electric system reliability while reducing the risk of a prolonged network shutdown or public safety issues. This update reflects that same sense of planning balance.

We discuss a phased implementation plan that will put the Company on track to meet the challenges we foresee today and position us to deal nimbly with new challenges as they emerge. In the next twenty years, our plan calls for investments of nearly $26 billion in capital investments (in real 2011 dollars) in our electric delivery system, or an average of $1.3 billion a year. Ongoing investment in our electric infrastructure is necessary in order for the Company to be able to continue to meet the energy demands of our customers in a safe and reliable manner. This level of investment, along with expected increases in the price of supply, results in an average annual increase in rates of 0.4% from 2011 to 2031. That is almost 1.0 percent less than the projected customer bill growth reflected in last year’s plan. This is mainly due to two factors: a 26% decrease in the projected supply cost per customer, from $57.80 to $42.92, and a 22% decrease in our delivery costs before taxes, from $22.19 to $25.98 per customer (and this despite the fact that in the updated plan, these numbers would include one more year of mild inflation, i.e. from the 2030 end of the original plan to the 2031 horizon for the update). The decrease in delivery costs represents the results of the cost-saving initiatives in 3G and asset management, totaling $7.5 billion in savings ($3.3 billion from the 2010 plan and $4.2 billion from this plan). This was partially offset by the $1.8 billion in extra system expansion costs mentioned above.

We remain sensitive that any rate increases impact our customers and we strive to keep rates as flat as possible. We have been successful in keeping the real price of electricity flat, on par with general inflation in the economy over the past 20 years. We fully recognize the importance of mitigating cost increases to our customers, and we are committed to keeping costs down as much as possible through continued cost management, efficiencies and innovations. We are committed to rigorously pursue regulatory and tax reforms as well. We are also mindful of the Company’s need to continue to attract large amounts of capital on reasonable terms.

We also recognize that utilities can play a key role in helping the federal, state and local governments meet their energy policy objectives. We are committed to working with various stakeholders (our customers, the community, legislators, regulators, and others) in order to implement our plan successfully.