BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY

Respondent.

DOCKETS UE-220066, UG-220067, and UG-210918 (*Consolidated*)

SHAY BAUMAN
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT SB-7

Puget Sound Energy Response to Public Counsel Data Request No. 330

July 28, 2022

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Dockets UE-220066 & UG-220067
Puget Sound Energy
2022 General Rate Case

PUBLIC COUNSEL DATA REQUEST NO. 330:
REQUESTED BY: Paul Alvarez

Advanced Metering Infrastructure (AMI)

Re: Advanced Metering Infrastructure. Sanem Sergici Workpaper, New-PSE-WP-SIS-TVR, Costs tab.

Notes [17]–[24] and [27]–[29] states that total recruitment cost per customer is $54.5, and that this is based on ConEd's business case.

a) Please explain, in detail, why Puget Sound Energy did not separately estimate this cost based on its own service territory and business case?
b) Please provide copies of the specific ConEd business case referenced.

Response:

a) Because Puget Sound Energy ("PSE") has not conducted a recent time-varying rate pilot, it is reasonable for PSE to rely on experiences from other utilities for cost estimates. Whenever appropriate, PSE did provide cost estimates that are specific to its system. For example, PSE provided capital cost and rebate costs that it expects to incur.

b) Attached as Attachment A to PSE's Response to Public Counsel Data Request No. 330 is a PDF copy of the ConEd business case.

ATTACHMENT A to PSE’s Response to Public Counsel Data Request No. 330

conEdison

Advanced Metering Infrastructure Business Plan

November 16, 2015

November 16, 2015

Consolidated Edison Company of New York, Inc. ("Con Edison" or "the Company") presents here its AMI Business Plan ("the Plan"). As stipulated in the Joint Proposal in Case 15-E-0050, the Plan includes a benefit cost analysis ("BCA") for the proposed AMI investment.

Several technical presentations were made to Staff and other interested parties regarding the Company's AMI Business Plan, pursuant to the AMI collaborative process in the Joint Proposal. This updated plan includes the most recent information received as part of our ongoing AMI technology and services evaluation.

Thomas Magee, General Manager

James Prettitore, Director

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1. Introduction

Con Edison is pursuing its Advanced Metering Infrastructure (AMI) smart meter initiative to empower its customers with control, choice and convenience. This initiative comes at a time when New York State is seeking to rethink and improve its energy future. The Con Edison AMI smart meter initiative is integral to this effort and, indeed, provides the foundation for such innovation and change. Additionally, it will help support the broader State goal of an 80% reduction in carbon emissions by 2050.[1]

In this document, Con Edison presents in detail the many benefits to its customers of such technology and then describes its proposed plan to implement AMI for all customers over six years, including the change management that will be necessary to effectuate a smooth transition to AMI adoption. Lastly, the Company presents for the Commission's review its detailed benefit cost analysis and the results of such analysis. The appendices contain supporting documentation referenced in the Plan.

The AMI smart meter initiative will fundamentally transform Con Edison's relationship with its customers by helping them become active energy consumers. The initiative will provide customers with the information necessary to help manage their energy usage, control costs and help the environment. Con Edison's AMI smart meter initiative is essential for enabling the enhanced customer features that will turn this vision into reality.

Why now? This is the optimal time for Con Edison to implement smart meter technology because of the convergence of three primary drivers:

- **Reforming the Energy Vision** (REV): Under the "Reforming the Energy Vision" (REV) strategy, the New York Public Service Commission is actively spurring clean energy innovation, bringing new investments into the State and improving consumer choice and affordability. The Con Edison AMI smart meter initiative will help meet the REV objectives of providing products, technology, and incentives for customers to actively participate in energy markets, control energy use, and take control of their monthly bill. AMI directly enables future engagement with the Company's customers, a primary goal of the REV initiative. With the appropriate data systems and web presentment in place, customers will have the opportunity to leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions.
- **Digital Customer Experience** (DCX): Con Edison's DCX initiative seeks to leverage state of the art digital technologies to enhance customer engagement and communication. The Company aims to deliver an enhanced customer experience which meets the customer needs of today and is flexible enough to anticipate and meet the needs of

[1] New York State Reforming the Energy Vision (REV); http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

tomorrow. With a "customer first" guiding principle, DCX sets the Company's direction while the AMI system provides the platform that helps bring it to life.

- **AMI Technology Maturity and Market Competition:** AMI technology has evolved rapidly over the past several years, making this an opportune time to embark on this project. Building on the success of other large global AMI projects, Con Edison will have the benefit of deploying a cutting edge AMI technology platform. Currently, the market is delivering new and exciting opportunities to engage all customers in meaningful and substantial ways. This industry maturity also means that the Company will realize the benefits of the most advanced communications infrastructure deployed at a very competitive price. Risk will also be limited due to the incorporation of advanced technology coupled with lessons learned from similar utilities who have already deployed AMI.

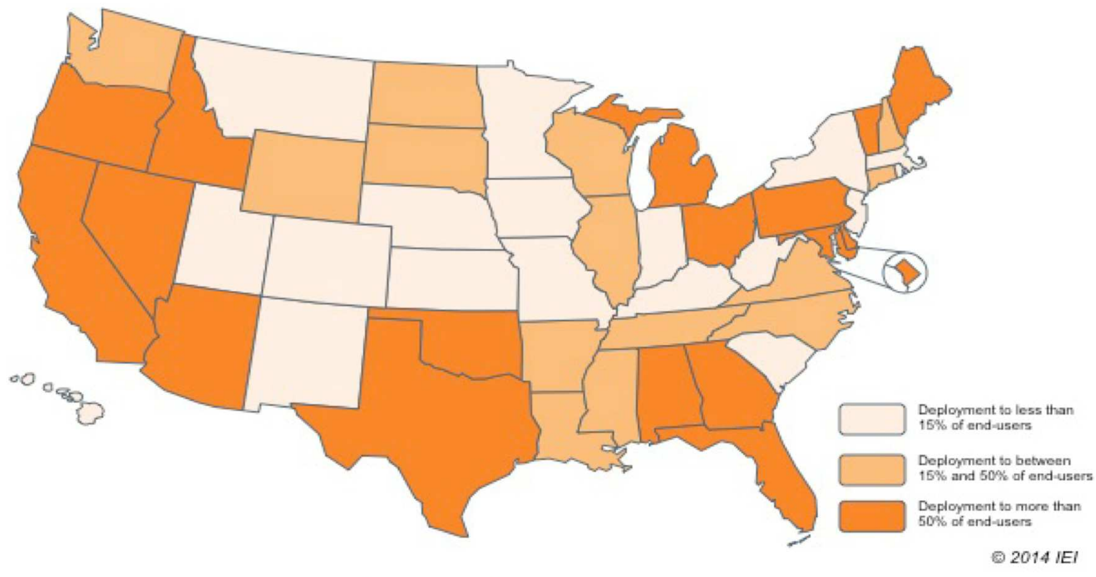
The valuable information provided by AMI will help customers make smarter decisions about distributed energy resources that fit their needs and values. Usage patterns may indicate that a customer would benefit by replacing an aging refrigerator or installing a battery or solar array. When integrated into the digital energy marketplace contemplated under the REV, such data will become invaluable to both customers and distributed energy resource providers as they bundle various products and services together to meet unique customer needs and provide solutions at scale.

The communications backbone implemented with AMI will also provide a critical, cybersecure link between grid operators and distributed energy resources. This communication link may also allow operators to dispatch and control certain resources as distributed energy resource markets develop.

1.1 U.S. Smart Meter Overview

According to the Edison Foundation Institute for Electric Innovation (IEI), as of July 2014, more than 50 million smart meters had been deployed in the U.S., covering 43 percent of U.S. homes. Figure 1-1 shows the extent of smart meter deployments by state that are either completed, underway, or planned by 2015.

Figure 1-1 Expected Smart Meter Deployments by State by 2015[2]



In order to understand lessons learned by other utilities and leverage that insight for the benefit of the Con Edison AMI project, Con Edison benchmarked with six peer utilities of similar size, scope and with similar urban topology. Since many peer investor-owned utilities have already implemented AMI, Con Edison is in a strong position to leverage those lessons learned for the benefit of its customers. The full benchmark report can be found in Appendix E.

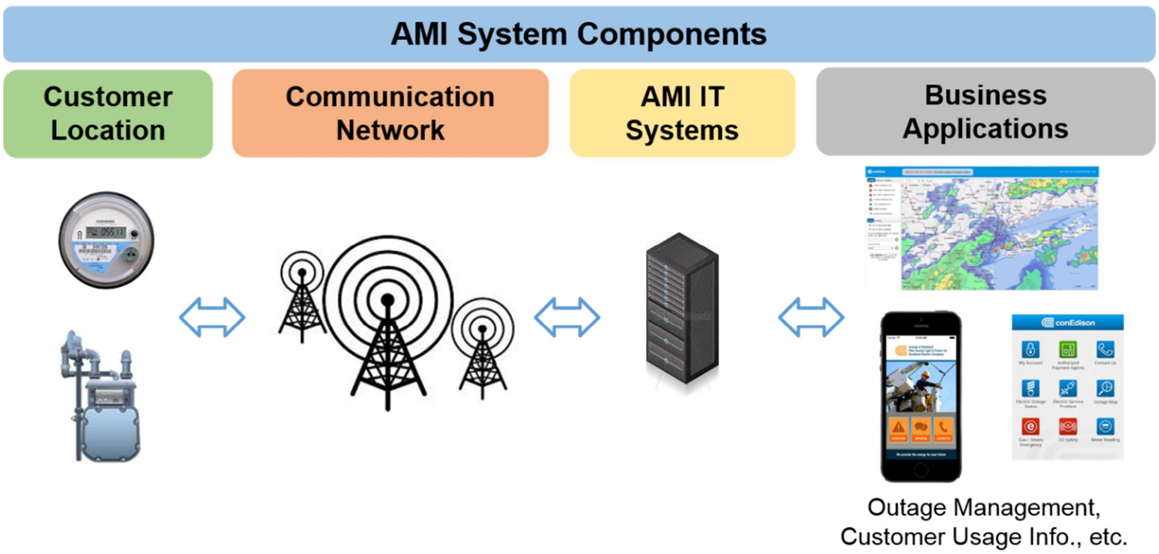
[2] Institute for Electric Innovation; September 2014. Map does not include automatic meter reading installations. Source: http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf

1.2 AMI System Overview

AMI systems provide granular energy usage information to utilities and customers. The AMI project is hardware intensive and involves replacement of meters or modules at every endpoint.

An AMI system has three major components: (1) smart meters (and associated communication modules), (2) a communication network, and (3) AMI back office information technology (IT) systems to manage the two way communications enabled by AMI. An overview of AMI System components is shown in Figure 1-2.

Figure 1-2 AMI Overview

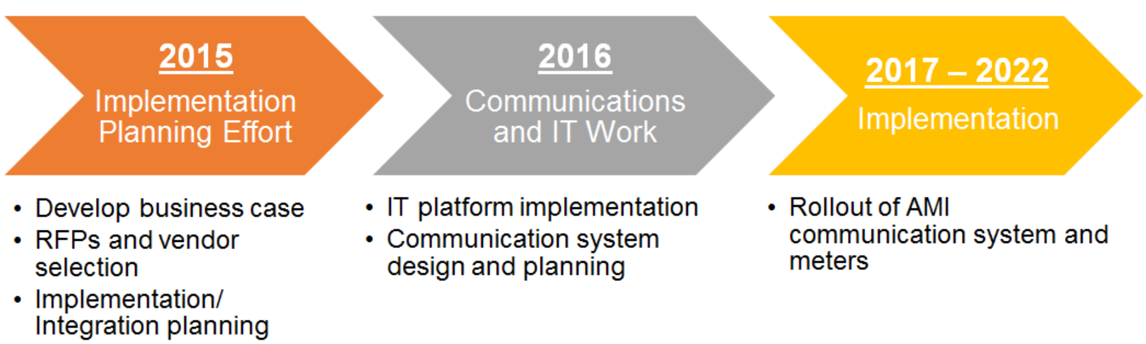


1.3 Implementation Plan Overview

Con Edison's AMI project is comprised of the following major phases which are also shown in Figure 1-3:

1) Implementation Planning Effort
2) Communications and IT Work
3) Implementation

Figure 1-3 High Level Implementation Plan Schedule



In 2015, the Company conducted a detailed planning effort for the AMI project which positions it to begin the AMI system implementation in 2016. Preparation included completing the detailed Benefit Cost Analysis (BCA) (presented in Section 5 of this document), selecting the AMI system equipment, software, and services that will be needed as part of the AMI project, and developing the AMI Implementation Plan. Beginning in 2016, the back-office IT infrastructure will be designed, configured, tested, and brought online to support the meter deployment. This initial infrastructure development requires approximately 12-15 months and is needed before the first meters can be installed. This infrastructure will provide the foundation upon which advanced capabilities can be developed to support customer enhancement and operational improvements.

Once all the new infrastructure systems are in place and tested, the Company's focus will shift from the internal architecture to deploying assets in the field. The assets consist mainly of communications devices, electric meters, and gas modules. The Company is targeting a five year period to complete the deployment of the communications infrastructure and more than 4.7 million electric meters and gas modules. Business transformation activities as well as customer and stakeholder engagement will continue during the field deployment work. Several options for deployment sequencing across the service territory were evaluated as part of this 2015 planning effort. Details of the three phases and considerations are included in section 4 of this report.

2. Customer Benefits

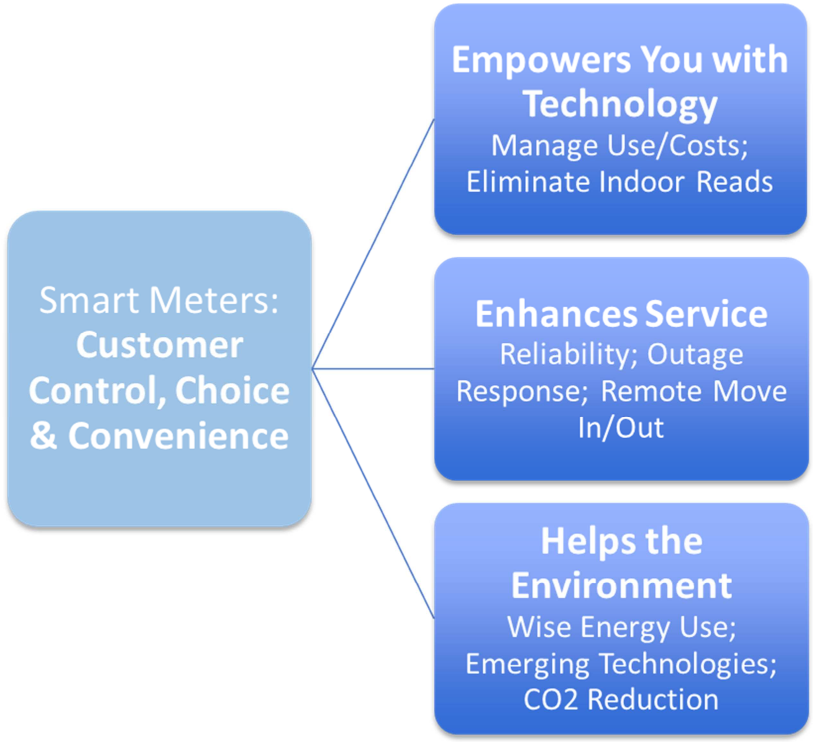


Figure 2-1 Customer Benefits of Smart Meter

To meet the objective of enhancing customer control, choice and convenience, the AMI project will provide customer-empowering technology, enhanced service to customers and numerous environmental benefits. These benefits will be translated into specific features, programs and service offerings, which will continue to evolve over time.

The Company plans to develop various customer products and services that only become possible with the two way connectivity and granular usage information provided by smart meters. Although cost control is a significant driver for most customers, it is important to note that Con Edison customers will also greatly benefit from the convenience of eliminating indoor meter reads and associated estimated bills. National research also shows that the potential for carbon reduction and other environmental benefits enabled by smart meters is highly valued by customers, as detailed below.

The Smart Grid Consumer Collaborative (SGCC) has conducted national research, which details the benefits that are important to the consumers. The summary findings are shown below in Table 1.[3]

[3] SGCC Consumer Pulse Wave 5. Con Edison is an SGCC member.

Table 1: Smart Grid Benefits

	TOTAL IMPORTANCE*	Important, but at no additional cost	Important, willing to pay more, but unable at this time	Important, and will pay more
RELIABILITY A smart grid senses problems and reroutes power automatically. This prevents some outages and reduces the length of those that do occur.	86%	48%	20%	18%
ECONOMIC Smart grids help customers save money by providing near real time energy usage information and the ability to manage electricity use.	86%	49%	22%	15%
ENVIRONMENTAL A smart grid reduces greenhouse gas emissions by making it easier to connect renewable energy sources to the electricity grid.	89%	47%	22%	20%

*** Sum of three importance responses to the right.**

In addition, Con Edison's Customer Advisory Community research has confirmed that saving money is the most important factor for customers (see Table 2).

Table 2: Alignment with the National Trends

Reasons to Manage Energy Usage	
Save money	89%
Cut out unnecessary energy usage	70%
Be more "green" / help environment	56%
Reduce Waste	52%

By installing two way interval meters for every customer, the AMI project will enable the Company to expand programs such as Demand Response allowing Con Edison to deliver significant benefits to customers and the environment.

2.1 Customer Benefits: Empowering Technology and Enhanced Customer Experience

The many customer benefits that AMI will bring are enumerated below. Each provides a new way for customers to engage with their energy usage, providing information and data that empowers them to better make decisions on choices regarding energy usage. Con Edison will be introducing programs and product offerings to empower customers and to improve upon their energy experience including the following:

- New advanced customer portal through which customers can:
  - Monitor energy usage in near real time

- View more detailed and actionable information to help active energy consumers control usage and costs

- Enhanced customer programs offering:
    - Alternative rate structures to reward energy conservation, especially during periods of peak demand
    - REV demonstration projects to evaluate programs to improve customer engagement
    - Enhanced Demand Response programs
    - Enabling all customers to obtain wholesale market benefits from changing patterns

Some notable utility examples of the benefits of AMI-enabled customer programs include:

- Sacramento Municipal Utility District's (SMUD) "smart home" rate, which helped reduce customer bills by 10-13% with time-of-use pricing enabled by smart meters
- Oklahoma Gas & Electric's (OGE) AMI-enabled demand response program, in which 99% of customers saved money; averaging $150 annual savings[4]

Through its Digital Customer Experience (DCX) program, Con Edison is leading the effort to create value for customers by developing an enhanced web portal to provide access to granular energy usage data. The portal will enable customers to leverage this information to gain insights about their energy use, and turn those insights into action. Specifically, the portal will:

- Provide customers with a simple, intuitive method to view their current and historical AMI meter usages, in graphical form
- Provide customers the ability to download usage data in various forms, including Green Button [5]format, the national standard
- Provide the ability to overlay additional data in graphical format, including weather, price, and bill cost data, as well as facilitating comparison to "neighbors"
- Utilize a customer analytics engine that leverages AMI usage data to provide the customer with insights and energy savings tips as well as personalized action plan to conserve and save
- Provide the ability for the customer to disaggregate their usage (i.e. understand what is driving their usage patterns) to determine how their energy is being used
- Provide customers with proactive alerts associated with projected billing, home energy use, and customized thresholds set by customers (energy use or projected costs)
- Provide the ability for customers to schedule the delivery of energy usage reports on an ongoing basis

[4] Data collected via interviews and conversations between Con Edison personnel and peer utilities during 2015

[5] http://energy.gov/data/green-button

Portal functionality will be tailored to specific customer segments such as residential, small business, and large commercial/industrial and optimized for viewing on all devices (e.g. mobile phones, tablets). In addition, the portal will be integrated with the Company's website, providing customers seamless access using a single sign-on process. The entire website experience, including the sign-on process, is being re-designed as part of the DCX program. This program includes the implementation of advanced web technologies and will ensure that customers can easily find and access information including the AMI Meter portal in a simple, intuitive manner. To ensure a consistent multi-channel experience, Customer Call Center employees will have access to the AMI meter data portal, which will allow them to better serve customers by allowing them to see what the customer is seeing. Finally, the portal will be aligned with planned REV demonstration projects to provide a seamless and integrated experience for customers participating in these demonstration projects.

The portal will be available to all customers in early 2017, upon receiving their new AMI smart meter, will allow customers to access their granular energy usage information and make use of the additional products and services available. To make customers aware of the valuable information and services available when their AMI meter is installed, customers will be prompted to sign on to the portal and will be alerted via email regarding the availability of new services related to their recent meter installation. See Figure 2-2 as an example communication:

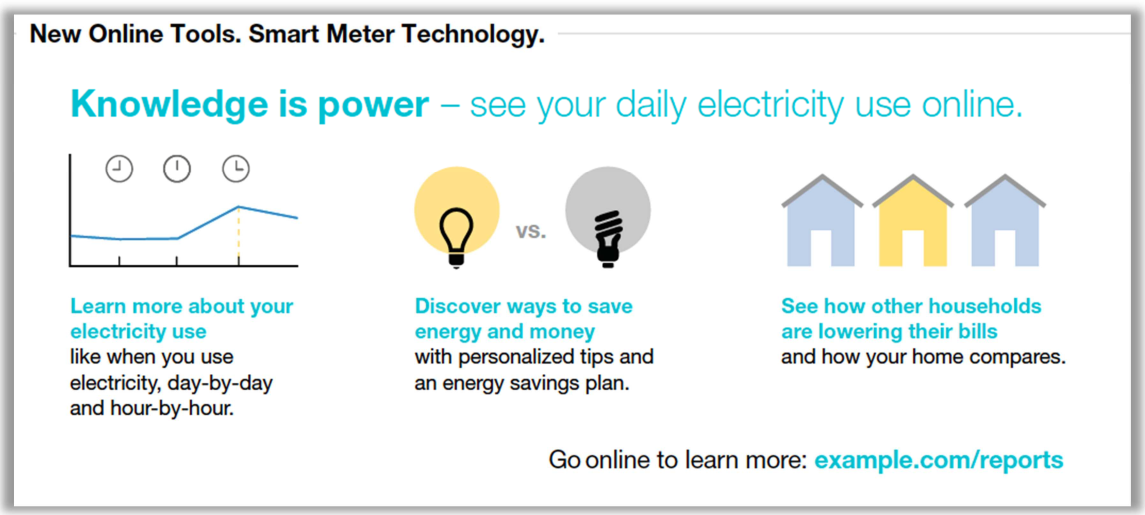


Figure 2-2 Proactive messaging and alerts under consideration for DCX

In alignment with the AMI implementation plan, customers with AMI meters installed in 2017 will have access to usage data from the prior day. Starting in mid-2018, customers will have access to real time usage data. The Company will utilize a customer centric approach to development, which will include channels for customer feedback during the process to allow the AMI meter data portal to address stakeholder needs.

Figure 2-3 summarizes the significant customer benefits, which will be made possible through the customer engagement portal.

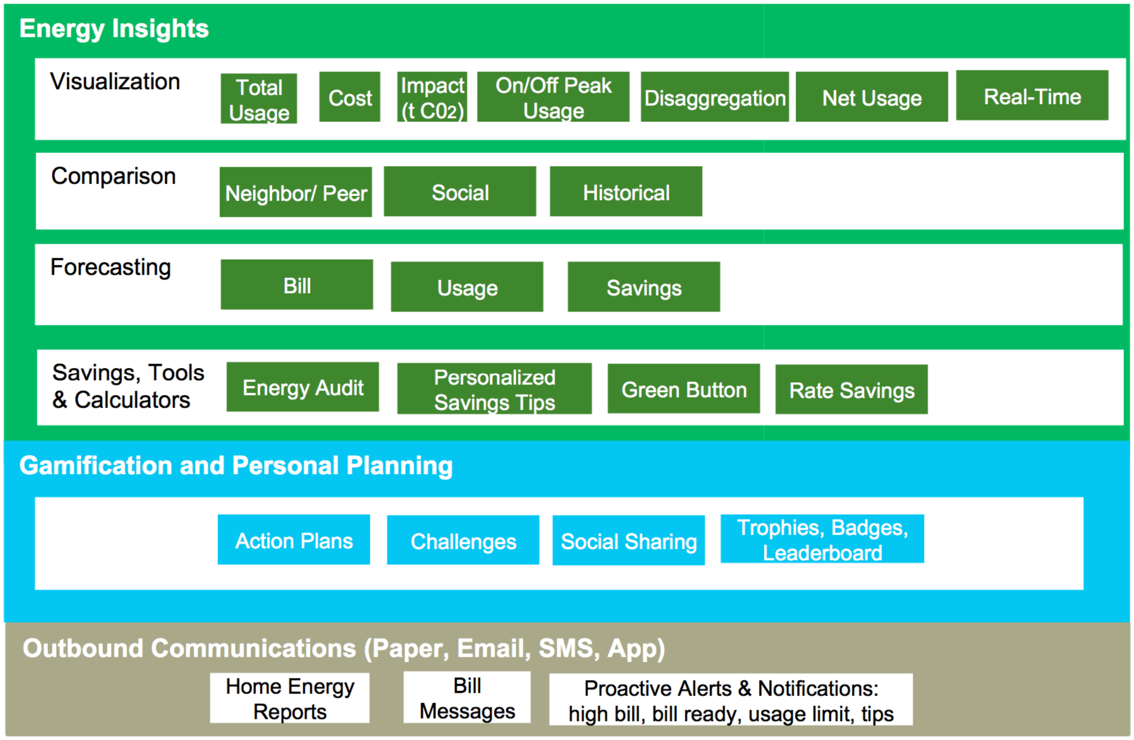


Figure 2-3 Various Functionalities under Consideration for DCX

Con Edison will continue to monitor market trends and customer preferences for other products and services, such as:

- Enhanced data driven tools to manage use and costs (e.g. gamification)
- Further enhancements to Demand Response (DR) programs
- Integration of Distributed Energy Resources (DER) such as solar / Distributed Generation (DG)
- Plug-in Hybrid Electric Vehicles (PHEV)
- Smart homes/smart appliances
- Voluntary prepayment programs

2.2 Customer Benefits: Enhancing Customer Service

Con Edison's customers will experience a number of other benefits that are less direct but that will result in an improved customer service experience. The AMI solution will provide opportunities to enhance customer service and improve reliability in the following manner:

- Eliminates need for indoor meter reads, which increases customer convenience
- Offers customized choices in billing date that better fits with individual financial needs, pay cycle, or other considerations
- Greatly reduces estimated bills and disputes surrounding estimated bills

- Provides new abilities to engage low income customers to help such customers manage usage and costs
- Provides easier service activation or transfer by leveraging the remote meter service switch
- Enhances reliability
- Reduces frequency and duration of outages in emergency situations

77 percent of customers surveyed[6] cited a preference for Con Edison to remotely read meters; this is one of the most noticeable changes that customers will experience. In addition, AMI's remote meter reading capability will eliminate the need to estimate customer usage when meter reading personnel are physically prevented from reading meters. The remote meter reading capability provided by AMI represents a significant convenience to the customer.

As illustrated by the national and Con Edison customer research cited above, customers highly value reliability in "blue sky" situations and especially during storm events. The reliability improvements from AMI include improved outage detection and restoration. Con Edison will enhance reliability and resiliency for customers by utilizing the AMI system to detect and respond to outages more quickly and to improve restoration times during large storm events.

Outage Detection and Restoration: The AMI meters can detect the loss and restoration of electric power and will provide this information in real-time to Con Edison's outage management system, augmenting the traditional outage notifications provided by customer calls and Supervisory Control and Data Acquisition (SCADA) systems. This will enable the Company to identify outages more quickly and facilitate efficient restoration activities. This is particularly crucial during storm restoration as it enables operators to efficiently dispatch repair crews to the impacted areas, provide more accurate estimated restoration times, and reduce outage times for all affected customers.

2.3 Customer Benefits: Improving the Environment

2.3.1 Greenhouse Gas Emissions (GHG) Reductions

AMI systems enable significant environmental benefits in three primary areas:

- Reduce GHG through Conservation Voltage Optimization (CVO)
- Reduce energy use through consumer behavior changes (e.g., expanded Demand Response Programs)
- Reduce vehicle emissions resulting from significantly reduced vehicle miles for:
  - Meter reading, service turn on/off and transfer
  - Avoided false outage service calls and efficiencies in service restoration following storms

[6] Con Edison Advisory Community survey; February 2015.

Conservation Voltage Optimization (CVO) increases the amount of information available to grid operators and planners, enabling Con Edison to better control voltage across the system, leading to a significant reduction in overall energy consumption. As a result, the Company is able to reduce the amount of power purchased and consumed, reducing the amount of electricity generated and the associated carbon emissions.

Analysis shows that by using CVO, the AMI system can be leveraged to reduce energy usage across the Company's service territory by approximately 1.5% on average, decreasing associated fuel use for committed generation resources. This results in an environmental impact of 1.9% fewer total CO_2 emissions due to the reduction of power generated by fossil fuel plants annually across the Company's service territory and a 1% total reduction in New York State. This equates to 229,125 metric tons and 368,821 metric tons of CO_2 across the Company's service territory and New York State, respectively.

According to the Clean Energy Greenhouse Gas Equivalencies Calculator[7], the statewide reduction equates to removing 78,000 passenger vehicles from the road or avoiding almost 900 million miles driven by those same vehicles.

Residential and commercial/industrial customers will have expanded access to products and service offerings that encourage energy efficiency, as detailed above. Each of these will result in environmental benefits that have not been calculated as part of this business plan but nonetheless are expected to be significant.

Remote meter reading and remote connect/disconnect have a quantifiable environmental benefit estimated as follows:

- Reducing the meter reading vehicle fleet by 80% over time or removing more than 100 vehicles, plus reduced personal vehicle mileage reimbursement results in a savings of approximately 54,000 gallons of gasoline annually.

[7] Equivalencies per EPA calculator at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results.

Fleet fuel savings at $173,250 / average $3.82/ gallon = 50,363 gallons of fuel saved annually. Plus, $41,500 savings in personal vehicle mileage costs at $0.55/mile = 75,455 miles / 20 MPG (estimated) = 3,773 gallons of fuel saved annually. Total gallons of fuel saved: 54,136

- Removing 481 metric tons carbon dioxide equivalent (CO_2e)

In addition, Con Edison calculates a savings in vehicle miles travelled due to reduced false outage service calls, as well as more efficient service restoration following storms.

- Avoided service calls accounts for approximately 49,500 miles saved. Using the EPA's 17.3 miles per gallon average[8] for light trucks, this results in 2,861 gallons of gasoline saved, or 25.4 metric tons CO_2e.

These elements combine to reduce greenhouse gas output and thus contribute to achieving broader environmental goals at the city, regional, state and national levels.

2.4 Compliance Management (Local Law 84)

The Company's proposed AMI solution will provide additional support and benefits to another type of customer - the property owners who must comply with Local Law 84. The City of New York issued New York City Benchmarking Local Law 84 in 2009 requiring property owners to capture and disclose energy use for the purposes of benchmarking resource consumption patterns. All City-owned buildings larger than 10,000 sq. ft., all private buildings larger than 50,000 sq. ft. and owners with groups of buildings collectively larger than 100,000 sq. ft. are required to participate in this benchmarking. Building owners are required annually to submit their energy consumption using an online tool (ENERGY STAR Portfolio Manager). Local Law 84 is part of the Greener, Greater Buildings Plan (GGBP), which is a comprehensive legislation focused on energy efficiency.

The AMI solution will enhance energy consumption transparency and inform building owners on how to make their buildings more efficient. Con Edison's AMI solution will collect consumption data from every meter with a granularity of at least 15 minutes. Due to the readily available data from smart meters, this could help increase Local Law 84 compliance. Con Edison plans to work with key stakeholders in focus groups to gather feedback and help improve compliance capabilities.

[8] Based on EPA data at in Fact Sheet titled, Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks (420f09024.pdf).

3. Reforming the Energy Vision Benefits

The AMI communications network and smart meter deployment provides the foundation to meet our customers' current and future needs, facilitate retail access programs and build the smart grid of the future envisioned by the Commission in the REV proceeding. AMI not only deploys technologies that will improve system visibility, enhance control, and support analytics that can help achieve various REV objectives but does so by providing a cybersecure information highway that includes all customers. Specifically, the AMI communications network will facilitate integration with DER components and Control Center operations, provide communication options and cybersecure messaging, and enhance the overall DR implementation process. This will allow the Company to align with REV guidance in the following ways:

- Enable both proactive and passive consumers to participate in REV and New York State Independent System Operator (NYISO) markets without the barriers to entry associated with cost and/or time to upgrade metering and communications
    - Facilitates adoption of renewable technologies such as solar
- Enable the installation of demand response, energy efficiency and other Distributed Energy Resources (DER) for customers[9] as well as behavioral changes to support indirect participation in REV markets. Note: An analysis of the potential residential sector Demand Side Management program expansion enabled by AMI was prepared by Nexant and is included in Appendix D. This analysis indicates that AMI enabled DSM for the residential sector alone results in a benefit of $90.4 million (20 year NPV) to the Company over the 20-year BCA analysis. The Nexant report summarizes a benefit-cost analysis for the implementation of a specific time-varying rate offered to Con Edison's residential customers based on a variety of enrollment scenarios. The estimates provided in the Nexant report were based on empirical research from pilots and programs conducted elsewhere and may be conservative in that they do not factor in the potentially significant impact of enabling technologies on demand response nor do they consider impacts for non-residential customers or from energy savings (as opposed to capacity savings) that can occur when time varying pricing (TVP) is deployed.

  Note that it is premature to conclude that TVP will ultimately be chosen as a rate design for large scale implementation, or if TVP, how such rate options would be designed in the Con Edison service territory. The Nexant report is meant to be illustrative of what demand reductions might be achievable in terms of alternative rate designs, but it is limited to TVP and does not represent all the potential pricing options that would be enabled by AMI nor does it encompass rate designs and pricing that will be developed pursuant to REV under Track Two.

[9] See 8/17 MDPT Report at page 90 which indicates "advanced metering supports increased granularity of information delivered on a timely basis. This supports better-informed customers, system planning and operation, and other third party stakeholders. Advanced metering can also support a number of the specific policy goals articulated in REV"

- Enable Distributed System Platform (DSP) functionalities through two-way communications for:
  - Engaging with customer-sited devices
  - Integrating with customer service and other internal systems
  - Informing engineering and operations modeling
- Adopt standards and protocols that support wide-scale DER integration, customer participation, market transactions, and operational control
  - The AMI communications network being deployed utilizes open standards and as such will enable not only integration of metering and customer sited resources, but also the integration of network protector relays and network protector switches (which will facilitate the integration of distributed resources) as well as capacitor bank controllers that may be required to maintain the proper system power factor to offset the impacts of distributed resources
- Facilitate DR and DER penetration resulting in system-wide efficiencies, enhanced visibility, and control functions:
  - Provide near real-time electricity usage and customer generation data as well as historical data to compliment Green Button Connect
  - Reshaping the load curve through responsive device integration
  - Providing fuel and resource diversity, while reducing carbon emissions

Most importantly, the Company contends that AMI is critical to support our customers' expectations of understanding their energy use and having ready access to usage data. This Plan considers smart meter and AMI communications a fundamental step towards enabling new options for the Company's customers, resulting in REV-related benefits in terms of overall system features as follows:

- **Enabling customers to better manage and reduce their energy costs** – With a fully enabled AMI system, all customers will have access to their interval electricity usage data, the granularity of which may increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers will have the ability to participate in new time-based rates such as the Smart Home rate and demand response programs offered by the Company and the NYISO without having to wait for and incur the cost of the installation of an advanced meter. With the appropriate data systems in place, AMI can also make customer electricity usage data available, per customer consent and security requirements, to third party providers who can provide additional services for customers.
- **Improved NYISO settlements** – AMI will allow the use of actual customer hourly consumption data in reporting hourly usage to the NYISO for settlement of the real time energy market and for determining installed capacity obligations. This will replace the current use of load shapes to allocate monthly usage to impute hourly consumption and will enable all customers to obtain the wholesale market benefits of changing their usage patterns. In addition, the ability to download the consumption data in near real-time will enable Con Edison to report more accurate usage to the NYISO for use the

initial settlement process, reducing the amount of resettlement required in the 4 month true-up.

- **Support NYISO Behind-the-Meter Generation Initiatives** – The NYISO is currently putting together plans for a new Behind-the-Meter Net Generation tariff that will allow net generators to sell capacity into the NYISO market. If the NYISO customers are paid like generators, they may require 5 minute or less interval meter data. AMI can provide the necessary revenue grade metering information to support this initiative with strict adherence to the confidentiality, integrity and availability of this data.
- **Improving system efficiency and resiliency** – The ability of AMI communications and smart meters to better monitor the Company's distribution system and performance of DER equipment can enhance quality of service and performance by enabling customer programs and technologies that may efficiently reduce demand and increase renewable generation. Real time monitoring of DER resources is essential to the DSP to track DER performance and capabilities both to make same day operational decisions and for near-term forecasts and scenario decisions. Con Edison's existing interval meters are equipped with cellular or phone line communications for selected customers as necessary to meet the requirements of the mandatory hourly price, reactive power and/or demand response programs. This solution is costly on a per meter basis due to high communications costs, communications reliability and inefficient installation routes, requires significant lead time and cost to set up new customers. Aside from Demand Response program participants during Demand Response events, our customers would not have the ability to obtain real time data. For the remainder of the interval meters, the existing system provides data after-the-fact and will not allow for real-time communication between DSP and customers with DER equipment when a significant number of DER sites are dispatched due to limitations in communication systems.

The Company and its customers will gain additional benefits because these programs and technologies can:

- **Improve Outage Detection and Restoration** – Provide customers and operators with real time outage management information and response time that will not only help traditional utility response but may also provide a road map for deployment of DER to aid in restoration.
- **Improve Industry Standards Compliance** – AMI utilizes telecommunications standards that will lower the cost of integration and development for many future REV-driven programs and plans across the utility enterprise. Standards-based communications will allow for greater security and improved management of the meter device system, while standards for communication data structures will improve integration with other systems. Specifically, AMI's back office information systems (Meter Data Management and the AMI "Head End" System) recognize standard integration protocols, including web standards (e.g. OpenADR, IEC 61968, MultiSpeak™) which may be used to develop demand response, responsive DERs, maintenance management, outage management, and customer service system integrations.
- **Reduce Carbon Emissions** – Operating the system at optimal voltages will reduce total energy consumption as well as associated emissions produced during power generation.

AMI can also reduce the amount of time needed to locate and restore faults, thereby reducing the number of personnel trips to the field and related vehicle emissions. AMI will also reduce vehicles on the road for meter reading and repair functions. Customers may also conserve electricity through increased awareness or by participating in time-based rate and demand response programs enabled by AMI.

- **Support Flexibility in Rate Design** – AMI is foundational to supporting demand charges as well as other new rate designs to provide customers with price signals that better reflect the actual costs their usage imposes on the system and, correspondingly provide the information necessary to more effectively manage their electricity and gas bills.

Con Edison's proposed plan to implement AMI will provide opportunities to improve economic efficiency and support the goals and objectives of REV by enabling the platform to potentially offer TVP options to consumers.

Although some believe these goals can be achieved without full scale utility deployment of AMI, many of REV's primary objectives, and especially those summarized above, cannot be achieved in the absence of full-scale deployment of AMI. Historically, a major impediment to customer participation in TVP programs has been the high cost of metering on an individual customer basis. This is especially true for mass market consumers such as residential households and small commercial businesses. If Con Edison's AMI plan is approved, the new metering platform will provide low cost opportunities for consumers to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply and delivery.

3.1 Third Party Access to Data/Green Button Connect

Con Edison's AMI project will directly support REV and the recent Staff White Paper on Utility Business Models (Track Two) in another important way, namely by providing the data that can be made available to third-parties, for a fee, to enable and support customer behavior change, as well as the tools necessary for the market to engage and drive solutions to scale. We have developed the following roadmap, which outlines our approach to addressing this need:

- **Existing Capability:** Currently, through its existing Customer Care portal and Green Button download capabilities, Con Edison customers can choose to share simple monthly usage data with third parties.

- **Transition:** The smart meter customer portal currently under development through Con Edison's Digital Customer Experience (DCX) initiative will include Green Button download as a base feature of the selected solution. The DCX initiative will deliver an improved online experience for customers, through a redesign that includes all external facing websites and mobile applications. As smart meters are installed, customers will have access to 15-minute interval data, rather than monthly usage data. This expands and facilitates the customers' ability to share more granular and actionable data with third parties across all customer segments.

- **Advanced:** Con Edison seeks to offer more robust data exchange functionality to customers, such as the Green Button Connect standard protocol. The national standards and robust capabilities of the Green Button Connect solution make it an attractive feature in terms of enhancing customers' ability to become active energy consumers. Specifically, Green Button Connect offers the following:
  - The ability for third parties to register with the utilities to be able to receive data via an automated data transfer mechanism
  - The ability for customers to log into the AMI Meter Data Portal and authorize access to usage data by a registered third party, on a temporary or permanent basis
  - The ability for third parties who are authorized by customers, to be automatically notified that they have been given authorization by a customer to view their usage data
  - The ability for third parties to make an automated request for usage data, for all data they have been authorized to access
- Green Button Connect is not included in AMI project funding; REV Track Two is addressing third-party access issues and may include the Green Button Connect feature.

Con Edison's initial review of Green Button Connect is favorable in terms of creating a common platform across the region, state and country. This functionality will allow customers to control sharing of data with third parties. The Company is currently evaluating various aspects including:

- Utility vs. vendor-provided solutions
- Costs, which vary widely according to benchmark data
- Customer and third party adoption rates

Con Edison is actively evaluating the Green Button Connect feature as part of REV Track Two and is engaging peer utilities, such as PG&E, SCE, and Com Ed. The Company has joined a monthly call with these peer utilities to understand how to leverage evolving best practices and develop the best solution for customers from both a functional and fiscal standpoint.

3.2 Leveraging the Value of the AMI Network

The AMI communications network that is being provided as part of this project may enable the following benefits in the future. This AMI project scope does not include any of the sensors required to enable advanced sensing or the equipment required to enable network protector control, but does include the communications infrastructure necessary to support such future potential improvements. The AMI network will continue to provide benefits as new sensors, data and applications become available. These advanced benefits of AMI include the following societal and system benefits:

- **Risk Reduction:** The AMI communications network has the potential to enable network protector switch remote control. Having the capability to control network protector switches would provide a significant risk reduction benefit as well as operations and maintenance (O&M) benefit to the Company. The Company has successfully enabled control of 175 underground network protector switches as part of the Department of

Energy (DOE) Smart Grid Investment Grant Project deployed in Staten Island. In addition, operation of meter service switches during a system emergency would provide Control Center Operators with a mechanism to surgically curtail load and is a significant value added benefit of the AMI network.

- **Distribution Automation**: In addition to the network protector control switches noted above, the AMI communications network provides Con Edison with the capability to communicate with distribution devices such as capacitor controllers and network protector relays. This ubiquitous network will have sufficient bandwidth and reliability to allow, where appropriate, the automated control and data collection from these critical devices.
- **Sensors:** The AMI communications network and data management systems provide an open platform for the addition of a myriad of sensors, which can help support Con Edison's distribution networks and the identification of potential problems or issues. Several sensor manufacturers are already working with the AMI community and developing the standards, based on conditions such as communications, to allow the low cost measurement and monitoring stray voltage, methane levels, carbon monoxide, pipe corrosion, air quality and fault current. As these sensors become available, Con Edison intends to evaluate their cost and effectiveness in terms of their potential to enhance customer service by improving reliability, public safety and responsiveness.
  - **Methane Detection** – Using the AMI communications network, new sensors and management systems could be deployed that will be able to detect natural gas leaks, thus enabling remote monitoring and improving response times to such events.
  - **Corrosion Potential Detection** – Using the AMI communications network, a benefit could be realized by deploying sensors that are able to measure the voltage at corrosion potential detection test points. There are approximately 40,000 gas piping test points across the Company's service territory that require an individual to visit and perform required manual testing; integrating sensors that monitor voltage could eliminate truck rolls and labor to perform testing, and provide continuous condition based monitoring (CBM).
  - **Arc Fault Detection and Reporting** – The Company has undertaken a Research & Development project to develop a solution to detect and report arc faults on the underground distribution system before they develop into safety concerns. The AMI communications system could provide the capability to remotely monitor abnormal conditions in the Company's network protector vault locations.
  - **Stray Voltage Detection and Reporting** – Sensors are being developed to provide remote monitoring capability of stray voltage. The AMI communications network could be utilized to enable remote monitoring and reporting of stray voltage on street lights and utility structures.
- **Streetlight Monitoring and Control**: In the US, Florida Power & Light has deployed a streetlight control system and Com Ed is considering deployment, among others. In addition, several large European cities, including Paris and Copenhagen, have worked with the AMI vendor community to enable enhanced monitoring of their city streetlights

and to begin controlling these streetlights to reduce energy consumption while improving lighting scenarios during specific times of day or events. The AMI solutions presently under evaluation by Con Edison offer these capabilities and, with support from New York City Department of Transportation (NYDOT) and the City, could improve the lighting experience for the citizens of New York[10].

- **Data Analytics**: The AMI solution will provide more than 1.5 billion discrete measurements every day from the electric and gas meters. This information will provide Con Edison with the opportunity to utilize or develop analytical tools to mine this information to identify electric and gas network issues or opportunities for improvement, to establish new services for its customers in support of distributed energy resources and to provide tools and opportunities to electric and gas customers to reduce or adjust their energy consumption. The data analysis can allow Con Edison to reduce system losses and improve the reliability of the electric grid through better load monitoring of network devices and the identification of areas with higher than normal losses. Several utilities are using AMI data to quickly assess the impacts of distributed resources, including electric vehicles, on the network and prevent overloading situations before they occur.

[10] AMI vendors have proposed the implementation of streetlight pilots as a value added demonstration.

4. Implementation Plan

4.1 Selection and Procurement of Technology and Services

As part of the implementation planning effort in 2015, key technology and service vendors will be selected through a competitive request for proposal (RFP) process. The technologies and services to be acquired are:

- **AMI Technology and Services:** The AMI technology includes electric AMI meters, communications modules for gas meters, the communications network, and the AMI head end system responsible for the coordination of the communication to all of the devices. The RFP was issued on May 15, 2015. The technical evaluation is complete and Con Edison is currently negotiating terms.
- **Meter Data Management System (MDMS) Technology and Services:** The MDMS is the central repository of meter data for the rest of the enterprise and is responsible for providing complete valid data to the other systems in the format and frequency they require. The MDMS is also the integration hub for AMI meter data where multiple systems can access validated data. The RFP for the MDMS was issued on June 24, 2015. The technical evaluation is complete and Con Edison is currently negotiating terms.
- **Meter Asset Management System (MAMS) Technology and Services:** The MAMS manages the meter and related metering components of the AMI system. MAMS provides the capability to manage the transfer, configuration, testing, and reporting of metering system field assets. It is designed to optimize asset tracking and manage maintenance efforts associated with the meters and communication system equipment. The RFP for the MAMS was issued on June 1, 2015. The technical evaluation is complete and Con Edison is currently negotiating terms.
- **Meter and Communication Installation Services:** Meter Installation Vendors (MIVs) and Communications Installation Vendors (CIVs) will likely be utilized to deploy the electrical AMI meters and gas AMI modules as well as the AMI communications equipment for the Company. These vendors will likely be responsible for the inventory, storage, staging, and labor required to perform the meter and communication system installation effort. The RFP for the MIV was issued on September 3, 2015 and the RFP for the CIV was issued on September 12, 2015. Proposals have recently been received and are under review. A variety of sourcing options will be considered for the field installation services.
- **IT System Integrator (SI) Services:** A SI vendor will provide a structured approach to IT System Integration services. This includes documenting all interface design requirements, proper coordination of the interface development, and proper execution of testing (system, integration, and performance). The SI will also support the development of solution architecture, and provide project management support. The RFP was issued on September 3, 2015. Proposals have been received and are under review.

The implementation of AMI at Con Edison is expected to be completed over a 6 year period and will leverage best practices to provide an optimal customer experience and reduce risk. The project will consist of four logical phases to reduce planning complexity and maximize control of the project. The strategic roadmap, shown in Figure 4-1, establishes the initial foundation to support the start of AMI network and meter deployment, and then builds upon this infrastructure to enable additional functionality and services while rolling out the meters and functionality to all Con Edison customers.

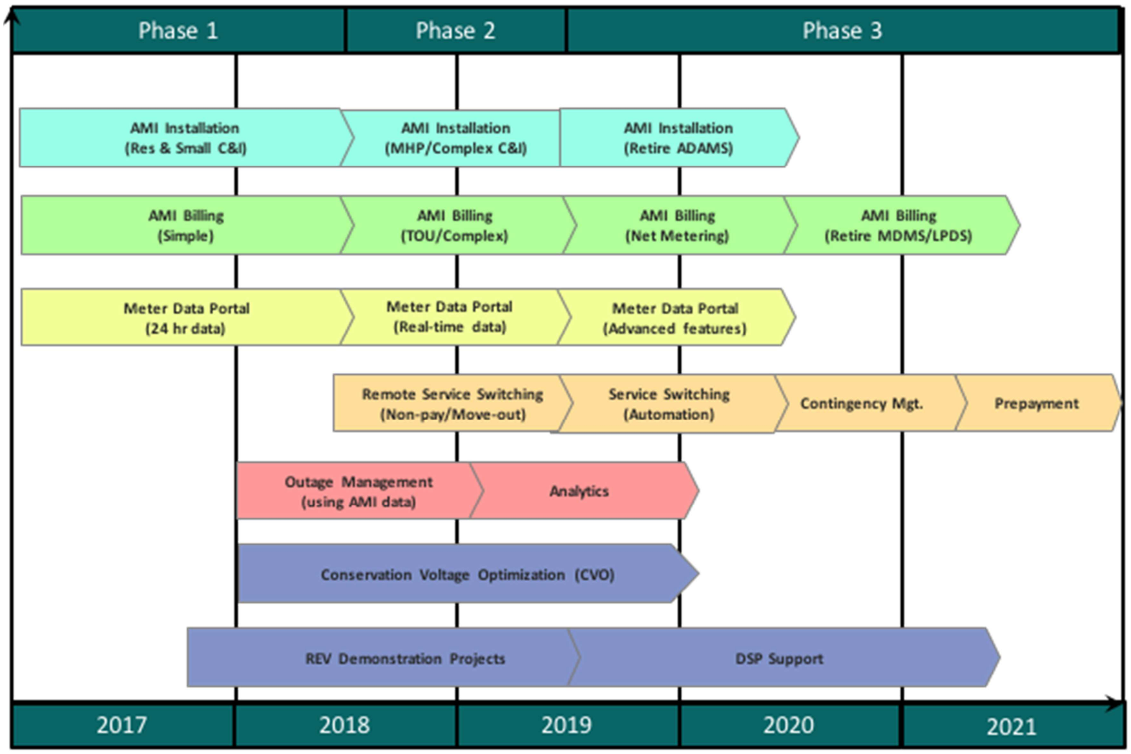


Figure 4-1 AMI Strategic Roadmap

The phases are as follows:

- **IT Platform Implementation Phase:** During this phase, Con Edison will configure, integrate and fully test the information systems necessary for asset, data and process management of AMI.
- **Phase 1:** Con Edison will receive, install, validate and automate the AMI meters while enabling customer access to data. This phase will also include the enhancements of the information systems and processes to allow complex metering and services.
- **Phase 2:** Con Edison will continue to deploy AMI meters and provide access to real-time data while utilizing the capabilities of AMI to improve the detection and management of outages, optimize grid operations and execute REV demonstration projects. This phase will also build upon the infrastructure to enable new services and analytics. Starting in 2018, a sufficient quantity of meters will be deployed to begin realizing advanced features and benefits, including outage management using AMI data, conservation voltage optimization (CVO), and potentially support to New York's REV demonstration projects.
- **Phase 3:** Con Edison will complete the deployment of AMI and decommission some legacy technologies. During this phase, Con Edison will be utilizing AMI to provide enhanced services to its customers and the retail access market. In 2019, analytics using

AMI data will be implemented for advanced purposes such as asset management, load forecasting, demand response, and theft detection.

4.2 Integration and Deployment Planning

Beginning in 2016, the back-office IT infrastructure, including MAMS (Meter Asset Management System), MDMS (Meter Data Management System) will be designed, configured, integrated, tested, and brought on-line to support the deployment and initial services of AMI. This infrastructure development will take approximately 12 to 15 months and is necessary to support the efficient and reliable mass deployment of up to 5,000 meters per day and management of the volume of data provided from the AMI meters. This infrastructure provides the automation and operational processes to manage the 4.7 million AMI meters to be installed over the subsequent five years and will provide the foundation for the project upon which advanced capabilities can be developed, in the future phases, to support customer enhancement and operational improvements.

While the back-office IT infrastructure is crucial to the installation and operation of the AMI network, the project personnel and business processes are equally important to a successful AMI implementation. Con Edison will be establishing the project organization and governance, developing an AMI operations center organization, designing and planning the communications network, developing the detailed process and plan for the deployment of meters and initiating the initial customer and stakeholder communications. The project organization will monitor and control the project leveraging standard principles for project management and reporting, including risk mitigation, activity tracking, vendor coordination and security monitoring.

With the start of the AMI implementation project in 2016, the AMI technology vendor will begin designing the AMI communication system to provide sufficient capacity and performance to meet the present and future requirements of AMI. This design process will include the development of standards and processes for the efficient deployment of the communications infrastructure and field surveys of network device locations. Con Edison will also conduct a detailed security assessment of the technologies and systems to ensure data privacy and cybersecurity.

In preparation for AMI meter deployment, the AMI project team will develop an AMI operations group. The initial AMI Operations Center (AOC) will be located at Company headquarters and will be integrated with an existing operations center. An AMI test facility will support the training of personnel and the validation of new technology and features. This facility will also support the 2016 activities to define the programming and configuration and fully test and validate the new AMI meters. The AMI operations center consists of the personnel, tools and operational processes to monitor and maintain the field equipment, the back-office systems and the AMI data to the reliability necessary to support the services and benefits of AMI.

Con Edison plans to utilize a Meter Installation Vendor (MIV) to deploy most of the electric AMI meters and gas AMI communications modules with the overriding objective being to deploy the system efficiently. The MIV will be responsible for the inventory, storage, staging, and labor required to perform the meter and module installation effort. Con Edison personnel will be responsible for the installation of the 265 volt interval meters, high tension meters, and Mandatory Hourly Pricing (MHP) program meters. Meter replacement will be organized by existing meter routes to maximize the installer efficiency and to allow AMI meters to be validated and cut over to the new services quickly.

During the Implementation Phase, the AMI project team will begin detailed planning activities for the meter deployment, which will balance multiple constraints and objectives. Components considered included installation complexity, change management factors, benefit realization, and other factors such as aligning with REV objectives, as shown in Figure 4-2.

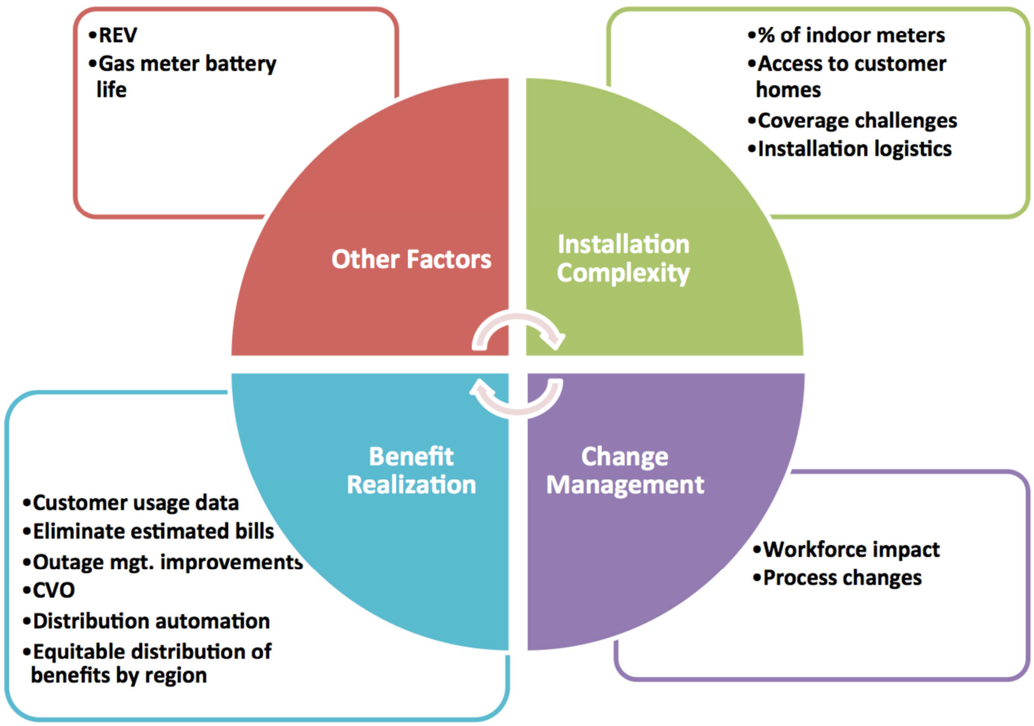


Figure 4-2 Meter/Module-Rollout Constraints and Objectives

4.3 Deployment Sequence

Con Edison has established an AMI meter rollout plan that maximizes initial deployment success, allows a measured and controllable installation across multiple boroughs, addresses impacts on people and processes, and yields initial benefits to customers. The rollout plan also accounts for the early deployment of the AMI communications network ahead of meter installations to allow AMI meters to be discovered and validated quickly.

In the Bronx, the existing AMR meters, deployed prior to the start of the AMI project, will continue to be read by the drive-by AMR technology. In order to realize future operational and maintenance cost benefits by having a common AMI head end system, communications network and meter, and to equip all meters with a service switch, beginning in 2019 all meters in the Bronx will be replaced with the new AMI meters with completion of the Bronx by 2021. Figure 4-3 illustrates the sequence of communications network and meter installation across the service territory.

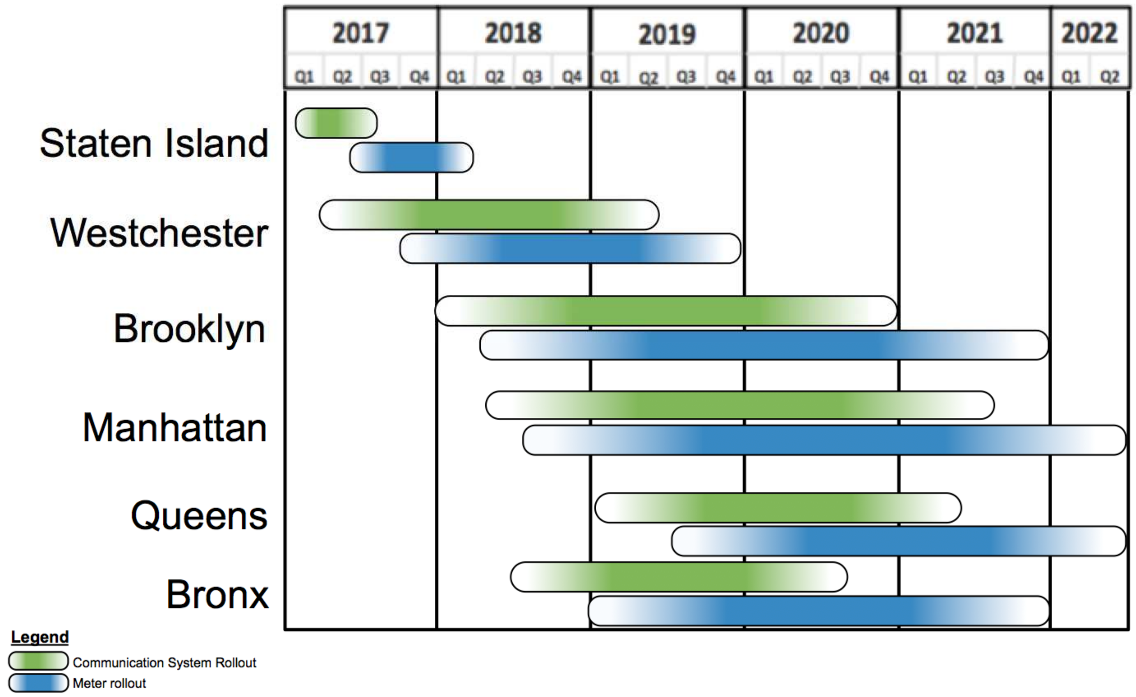


Figure 4-3 AMI Deployment Sequence

Phase 1

Upon the completion of the design and planning activities of the Implementation Phase, field deployment and commissioning of the communication network and meters will begin. Deployment of the communication network equipment by the CIV will begin approximately three to four months before the first AMI meter installation to allow for sufficient communications reliability for any installed meter. Con Edison customers and local agencies will receive advanced notification of the impending meter installations, consistent with the Communication Plan.

The deployment of AMI meters will begin slowly in Staten Island to ensure that all of the business processes, information systems, and deployment tools are operating properly to minimize disruption to customers and normal business operations. Once these are validated, the deployment rate will increase and AMI deployment will expand to the other boroughs consistent with the rollout plan described above. Phase 1 will include the regular transition of AMI network and AMI meters to the AMI Operations Center (AOC) as these devices are commissioned.

Phase 1 will provide these first recipients of AMI meters with access to the collected energy consumption through Con Edison's new digital customer experience portal DCX as well as bills calculated from the AMI data. Con Edison plans to reach out to customers following the deployment of meters to inform them about accessing and utilizing the AMI data.

Phase 1 will include the design, configuration and testing of advanced features of AMI and the integration of the back-office infrastructure with other systems, including OMS (Outage Management System) and CVO (conservation voltage optimization). These new features and services typically rely on sufficient deployed volume of AMI meters to achieve the expected benefits. Con Edison also expects to add functionality and integrations as necessary to support New York's REV pilots and projects which may be identified. The Phase 1 development activities will also incorporate lessons learned from the initial meter and network deployments as needed for process changes and additional tools and analytics.

By the end of Phase 1, Con Edison anticipates that Staten Island will be the first borough to be fully deployed with AMI meters, and the deployment will start in Westchester and Brooklyn. Additionally, the deployment of the AMI communications network should be initiated in Manhattan.

Phase 2

Phase 2 starts with the completion of the design and configuration activities identified above during Phase 1. The field deployment of the communication network and residential and small commercial/industrial meter endpoints from Phase 1 continues in Westchester and Brooklyn, and will start in Manhattan and the Bronx. The field deployment will expand to include commercial and industrial customers with existing interval meters to add support for MHP, Demand Response and other complex rates.

Phase 2 represents the introduction of new services and capabilities enabled from Con Edison's AMI technology. Building upon the digital customer experience from Phase 1, Con Edison's customers will be able to access the real-time data from the AMI network as well as other features and capabilities of self-service and notifications. Con Edison will begin utilizing the AMI network and meters to improve the detection and management of power outages and may begin executing pilots for REV and grid optimization. Con Edison will begin using the remote switch in the AMI meter to remotely connect and disconnect customers.

Similar to the previous phases, Phase 2 will also include new design, configuration and test activities and new integrations to further enhance the value of the AMI infrastructure and to provide new services to Con Edison's customers. During Phase 2, Con Edison will retire the existing meter asset management system (ADAMS).

By the end of Phase 2, the deployment of AMI in Westchester County will be in the "clean-up" stage focused on premises requiring special attention or skipped due to access or service issues. AMI should be active throughout the service territory as the AMI deployments in the Bronx, Brooklyn and Manhattan will be well underway and Con Edison expects the network deployment to have begun ahead of the deployment of meters in Queens.

Phase 3

Phase 3 is the longest of the planned AMI project phases. During this phase, the AMI project will complete the meter deployments in Westchester County, Brooklyn, Manhattan, the Bronx and Queens. This phase will also include the decommissioning of the CIV and MIV deployment facilities and the transition of the project activities to the operational groups within Con Edison.

Phase 3 will continue the introduction of new services and capabilities developed in Phase 2, including contingency management and DSP provider services, as these services become defined under the REV initiative. Phase 3 will include, if appropriate based on PSC and REV initiatives, the rollout of alternative rate structures. Con Edison anticipates the need to support additional REV pilots, market services and other external requests to utilize the deployed AMI technology. During Phase 3 Con Edison will retire the existing MDMS with the complete migration of functionality to the new platform.

Phase 3 also represents the opportunity to enhance the use and operation of the AMI network and meters through data analytics and operational process improvements. Con Edison will develop tools and procedures to improve the performance of the AMI technology with better monitoring and utilization. Con Edison will also improve the analytics capabilities to support the development of new services and improvement of grid operations.

At the end of Phase 3, Con Edison expects that all of its customers, other than those who have "opted out" of participation in the AMI program, to have received AMI meters and that the AMI technology is functioning at the required service levels and performance. Con Edison will transition from project mode to operational mode as the AMI project and capabilities will become part of the normal day to day business operations of the utility.

4.4 Change Management

Customer experience and benefits are of utmost importance for every phase of the AMI project. In order to continue bringing positive experiences to the customer, Con Edison has recognized the central role that Change Management (CM) plays in the AMI project lifecycle. Change Management encompasses external Customer Engagement and internal Organizational Change Management (OCM).

The Change Management portion of the AMI project will employ a diverse, inclusive and multi-faceted approach to address the internal and external impacts on the people and processes associated with the AMI technology implementation. The associated goal is to build understanding of the benefits, resulting in high-level organizational performance and customer satisfaction across demographic segments and beyond as enhanced customer features are introduced over time.

To enhance the customer experience, the Digital Customer Experience (DCX) initiative is focused on redesigning Company web sites and engaging customers to drive adoption and use of various customer-enabling features and programs. In addition, Con Edison established an industry benchmark peer group and conducted primary and secondary research and plans to continue to engage with these peers throughout the life of the project. Benchmark discussions and site visits began at the outset of the project in January 2015.

By directing Con Edison's external communications approaches and resources toward the customer enabling vision, Con Edison expects to make tangible changes in how customers use energy.

4.4.1 Customer Engagement Plan

Con Edison has defined its overall engagement strategy, summarized in Figure 4-4.

Focus on customer benefits

- New options for customer control of energy use and costs

Leverage research and best practices

- Customer Advisory Community surveys, national research, benchmarking with peers, and REV forums

Communicate openly

- Meter install plan and process

Preview enhanced features

- Promote adoption and use for energy savings

Address key concerns

- Price, privacy, health, and safety

Figure 4-4 Customer Engagement Strategy

By using this strategy to guide the customer engagement approach Con Edison aims to achieve high customer satisfaction throughout the AMI project lifecycle

4.4.2 Communications Objectives & Tactical Plan

Customers can be reached and engaged across an increasing number of channels, such as:

- Traditional/Print
- Community-based marketing
- Public Relations
- Government Relations
- Electronic
- Social Media Presence

The customer engagement plan will address the communication methodology for all types of customers: residential, small and mid-sized commercial and large commercial/industrial. Con Edison will build on its existing outreach to these demographics, as well as leverage lessons learned from peer utilities. Large commercial and industrial customer needs will continue to be addressed with highly customized, one-on-one methods consistent with Con Edison’s existing large accounts approach.

Additionally, Con Edison will continue to utilize:

- The Smart Grid Consumer Collaborative (smartgridcc.org), which monitors trends, conducts national research, develops tools, and provides insights related to AMI
- Customized benchmark research from its peer utility group, which will continue to provide lessons learned and examples from similar utilities with AMI implementation experience

4.4.3 Tactical Communications Plan

Con Edison is developing a detailed tactical communications plan to support smart meter deployment and achieve the communications objectives outlined above. As an example, an early item is the development of an infographic that will serve as the anchoring statement of customer benefits over time, shown in Figure 4-5 below.

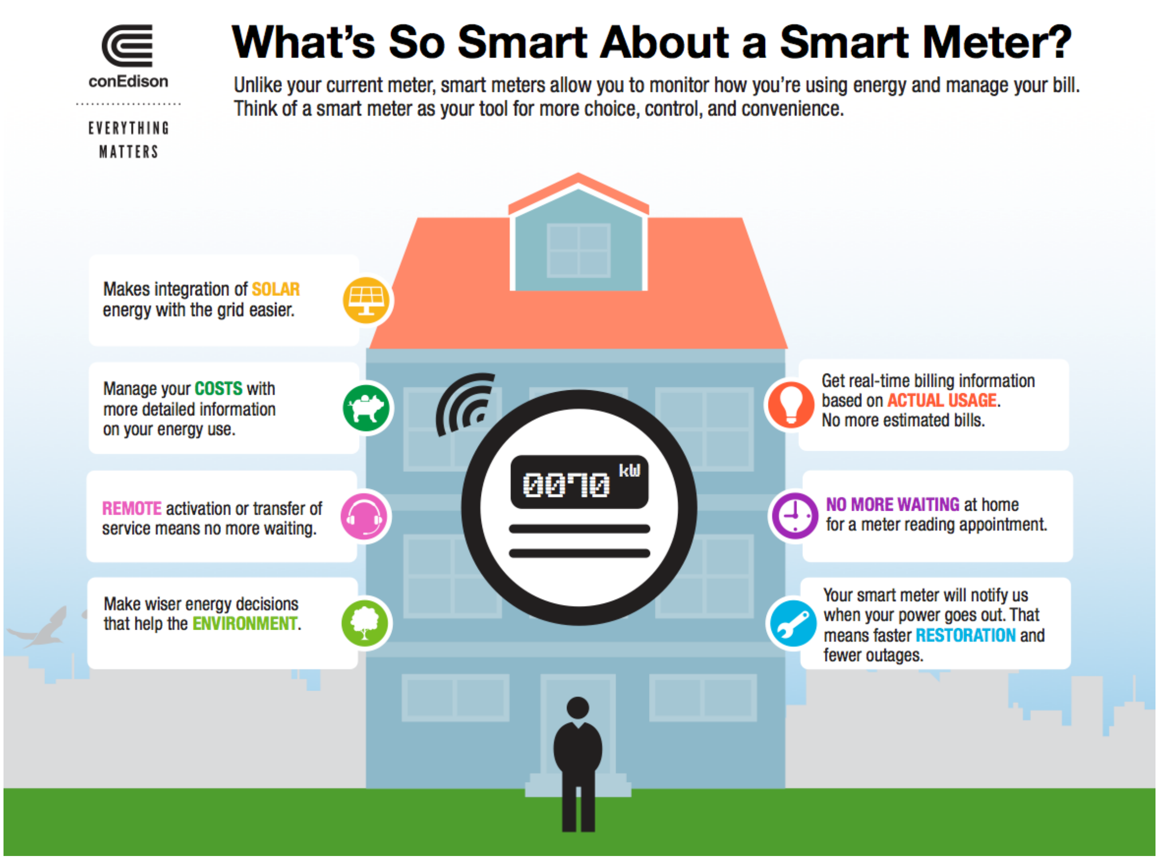
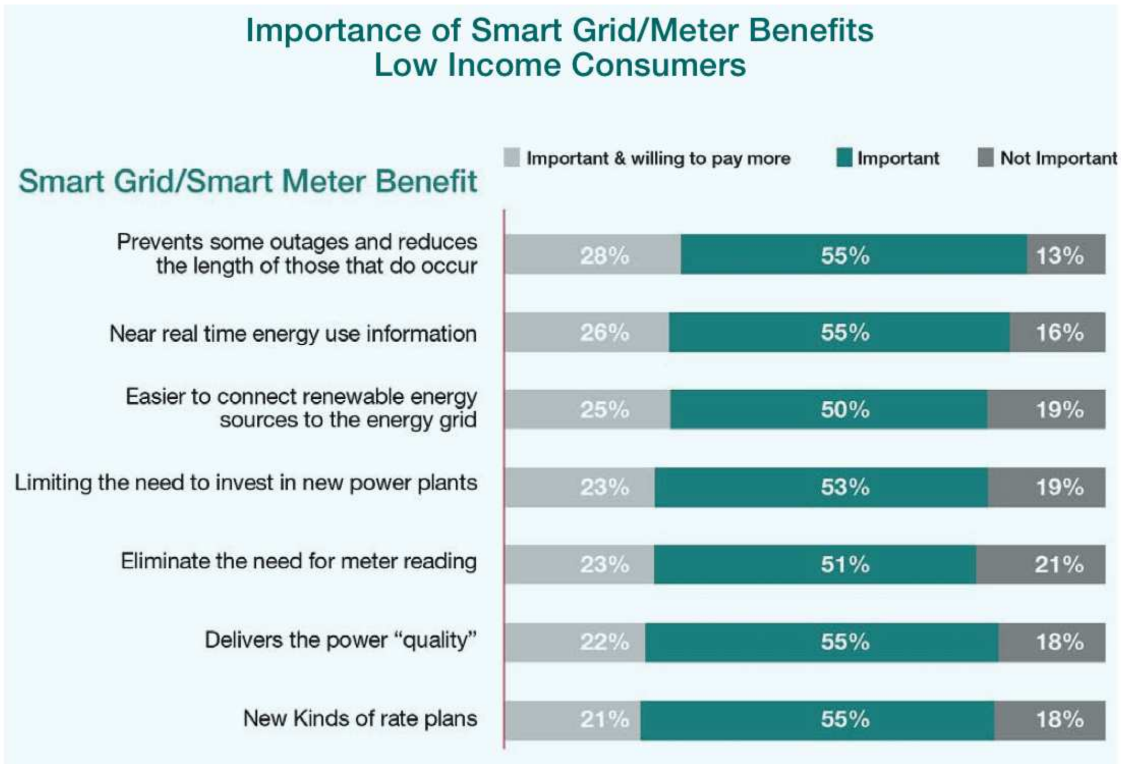


Figure 4-5 Smart Meter Infographic

4.4.4 Low Income Customers

For low income customers, additional attention is required to build awareness and understanding. Con Edison will build on its existing outreach practices to provide engagement opportunities for low-income customers.

Figure 4-6 summarizes the benefits research conducted by SGCC with low-income customers.



Base: Total Low income respondents n=1001

Figure 4-6 Low Income Customers and Perceptions of Benefits

Low income customers value smart grid benefits, such as avoided outages and high reliability. These customers also are interested in opportunities to save energy and money.

Figure 4-7 shows a usage alert communication under consideration by the DCX team. Similar usage alerts could be particularly engaging for low income customers.

Specific implications cited in the SGCC research[11]:

- The need to continue effective customer outreach remains
- Concerns need to be understood and addressed
- Pre-pay and time-of-use pricing merit further exploration

[11] Spotlight on Low Income Consumers II, April 2014; page 16.

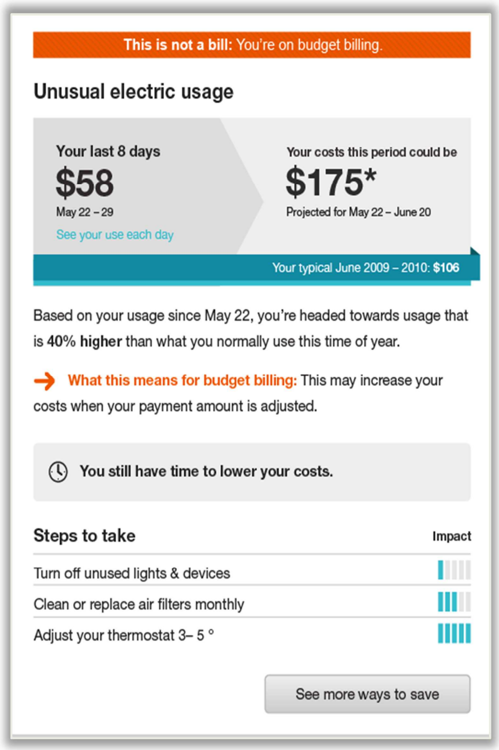


Figure 4-7 Usage Alert

- Participation rates in energy efficiency programs among low-income consumers can and should be improved
- Strategies and tactics should be developed targeting the needs of renters to help them take advantage of energy efficiency technology and reduce household energy consumption
- The needs of older low-income consumers need to be addressed

Con Edison will continue to support the low income population as it prepares the smart meter engagement strategy and will build on practices already in place to effectively meet the needs of all demographic groups.

4.4.5 Meter Deployment Communications Schedule

For deployment of the communications infrastructure and meter installation, Figure 4-8 illustrates the overall customer engagement sequence leading up to and following the start of the initial installation routes in Staten Island and Westchester. Note that communications materials (e.g., website, FAQs) will be developed and available well before the start of installation. This same sequence will be followed for all meter installation routes throughout the project lifecycle.

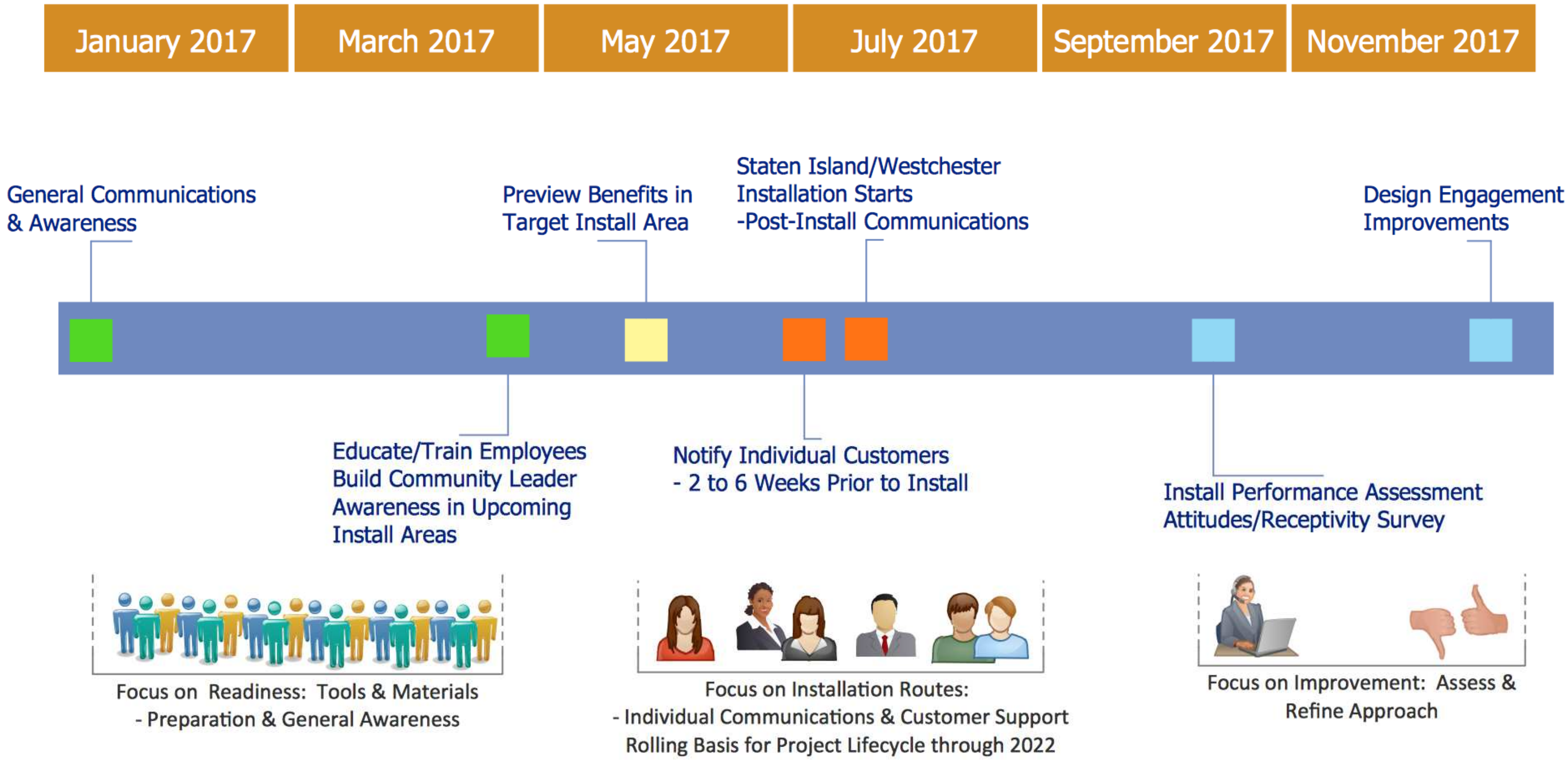


Figure 4-8 Customer Engagement Sequence to Support Meter Installation

The development of an overall strategy is a critical first step. At least a year prior to the start of installation, the communications strategy will be finalized. General AMI communication has already been underway via website information, Public Service Commission (PSC) briefings, and board presentations.

In the case of AMI communications network deployment, the plan does not include notifying individual customers at this time. During this phase there will be general information available through various resources (e.g., website). In the case of meter deployment, however, community engagement will begin on a rolling basis, with individual notification and post-installation follow-up aligned with the meter deployment schedule.

The employee education at the three to four month point (noted in the figure above) differs from Organizational Change Management (OCM) employee communication, which starts much earlier. From an external customer engagement standpoint, this step relates to making employees aware of the meter installation process and the timeline.

4.5 Organizational Change Management

Using industry-standard OCM processes, Con Edison will support the workforce in its ability to perform well and realize the customer benefits made possible by smart meter deployment.

OCM planning and implementation can be divided into three phases:

- Phase 1: Prepare Strategy/Assess Change
- Phase 2: Manage/Implement Change including component Sponsorship, Communications and Training plans
- Phase 3: Reinforce/Sustain Change

There are two basic elements that define the tactical actions that form the basis of OCM planning:

- Impacted stakeholders
  - Daily job duties will change based on new technology tools and associated business processes
- Staff displacements
  - Fundamental shifts in work requirements and job duties that permanently reduce staffing levels

Detailed 'future state' Business Process Models (BPM) have been developed to capture the associated organizational changes and include the following macro-level processes:

- Meter to Bill
- Connect – Disconnect
- Asset Lifecycle
- Meter Deployment
- Events & Alarms

Impacted organizations and departments have already been identified and will be leveraged for the OCM plan implementation including sponsorship and engagement, communications and training.

4.6 Labor Plan

To address the organizational change impact, Con Edison is developing a detailed approach regarding how labor will be affected by the phased implementation of AMI through 2022. Con Edison will develop a plan that seeks to protect the interests of its workforce as it has done historically, and balance that with its transition to new technology that signals changes in its business operations and practices. That plan will follow from both the implementation plan for AMI, and from the implementation of REV as it develops, as well as the Company's overall business needs for all the services it provides, not limited to electric service. As this Business Plan indicates, the savings that are contemplated from AMI implementation are not limited to savings on labor costs, but include multiple other benefits such as outage management, customer satisfaction and other societal benefits.

To accomplish a smooth workforce transition, the Company will utilize its Human Resource strategy, along with the Virtual Enterprise Modeling (VEMO) model. VEMO is a robust workforce planning tool to help managers identify workforce needs in the future, to identify gaps between demand and supply for physical workers, and to develop resource related strategies for improved long-term resource planning. The Company selected and designated a workforce planning analyst who will manage and develop data reports to be used in the workforce planning process. Effective workforce planning is a continuous process that ensures an organization has the right number of people in the right jobs at the right time.

The Company built a series of reports in this application on attrition, projected retirements, age and service analysis, headcount trends, trainee titles, etc., which could be run based on the Companies' organizational hierarchy or these talent segments or a combination of both. In providing organizations with data on attrition, the operational and other areas are more actively involved in projecting what their losses will be and addressing their replacements in a more proactive fashion. Allowing organizations access to information about their outflows and inflows in their sections will improve the knowledge they apply to their resource planning and will improve the ability to better manage its workforce, both with respect to optimal levels and cost management. The implementation of the workforce planning process has allowed the Company to manage their respective staffing levels.

4.7 Cybersecurity Plan

The Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program. This program is designed to protect Company computers, servers, business applications and data, and high value networks from unauthorized access and control from both external and internal threats. We also recognize that the threat landscape constantly evolves and expands and that it is critical to continuously improve our defense posture through investments in technology, improvements in our cybersecurity processes and through collaboration with law enforcement, regulatory and industry resources.

While the details that underlie these dimensions may change over time, the Company's cybersecurity program is built on the following foundational principles:

- Cybersecurity should be based on a comprehensive risk assessment, including increased focus around the security tenets (Confidentiality, Availability, and Integrity) that apply to the items being protected

- Cybersecurity is designed into all computing and communications elements used by the Company and our customers
- Computing networks are segmented to ensure that high value networks such as control centers are separated from the corporate information network
- The defense posture is layered, eliminating dependence on any one cybersecurity defense
- Regular vulnerability assessments and penetration tests are conducted by independent third party experts
- Access to computing and communications assets are limited based on “least privilege needed”
- Redundancy and diversity are built for all components to reduce impact and effect recovery

Computer security will remain a major concern for the Company for both the short and long term, as malicious software and intrusions continue to become more sophisticated. The actors are changing and increasingly have the skills to employ stealth techniques over time that attempt to evade and disable current detection mechanisms. They methodically attempt to exploit vulnerabilities in access controls and software products using slow, persistent attacks to compromise weaknesses, a technique referred to as Advanced Persistent Threat.

We continuously improve our defenses. In addition to the cybersecurity elements described in this and accompanying documents, we are planning the following improvements in the near future:

- Expand the use of intrusion detection and prevention technologies
- Expand the use of next generation web and database firewall technologies
- Expand the use of correlation and big data analytic technologies
- Deploy the next generation of remote access technologies which take advantage of better authentication methods like Adaptive Authentication and Mobile Device Managers (MDM)
- Improve employee awareness about cybersecurity through training and communication

4.7.1 Cybersecurity Plan for AMI

The Company has defined and implemented a formal cybersecurity policy using International Standardization Organization (ISO) Standard 27002 as a reference model. The foundation of ISO 27002 is to ensure the confidentiality, integrity, and availability of systems and data through a process to regularly evaluate all aspects of the program, including review of policies, standards, and procedures in addition to the actual implementation of technical controls. These objectives support the Company’s goal to provide reliable electric, steam, and gas service to commercial entities, government agencies, and consumers.

Con Edison has a portfolio of over 500 business applications aligned with the corporate business strategy and the companies’ electric, gas and steam long range plans to support current business needs and future directions. Cybersecurity for business applications begins with corporate governance that establishes requirements for application information security and control. Cybersecurity governance is elucidated through corporate policies and instructions that contain the specific requirements business owners and application developers must meet for software development and business application security. These corporate policies and other supporting procedures provide the framework for application software development and support, including asset classification, protection of sensitive information, control of information exchanges with business partners and other external organizations, business application access controls, user access management, and disaster recovery.

Business application assets are protected by security controls, including those designed for information in databases and accessible through software applications, built into the applications during system design and implementation through the use of a Software Development Life Cycle (SDLC) process. Key governing principles applied to new systems following the SDLC process include:

- Architecture reviews of procured systems to ensure proper design and incorporation of security controls
- Secured coding principles utilized for developed applications
- Role based access controls implemented throughout the system
- Systems designed to ensure data flows follow data pull techniques from "High Trust" to "Lower Trust" networks. Data is never to be pushed into "High Trust" from "Low Trust" networks
- External data exchanges are encrypted to protect information transmitted between business applications and external organizations.
- Authentication techniques utilized by users and system components

New corporate initiatives include the use of devices (smart meters, distributed generation systems, etc.) not deployed within the Corporate Network. These devices add risk to the Company as they are outside the company's physical security controls. Accordingly, all external devices and systems are designed in a manner to ensure the integrity of the network and data being returned to company managed systems. Key principles used for these initiatives include all previously discussed controls and the following for all physically uncontrolled devices (meters, battery storage systems, etc.):

- All devices must be identified during the manufacturing process as a device intended for the Company's system
- Authentication to and use of dedicated, encrypted networks for the secured transmission of data from external devices
- All external data collected and temporarily stored in a "Low Trust" zone until pulled into the corporate environment from a "High Trust" zone
- All control/change activities initiated from management systems to external devices authenticate to the external device

- All software/firmware updates are received from the vendor via secured and validated means
- All physical access to external devices are initiated with authorization and authentication controls from the management system for a defined period of time
- Logging of all approved changes/commands with alerting of unauthorized activities

The AMI vendor cybersecurity practices were reviewed during the RFP process.

4.8 Benchmarking of Peer Utilities

In order to understand lessons learned by other utilities and leverage that insight for the benefit of the Con Edison AMI project, Con Edison benchmarked with six peer utilities of similar size, scope and with similar urban topology. Since many peer investor-owned utilities have already implemented AMI, Con Edison is in a strong position to leverage those lessons learned for the benefit of its customers. The full benchmarking report may be found in Appendix E.

The objectives of this benchmarking exercise were as follows:

- Gather data from peers on practices contributing to AMI project success
- Highlight impediments and lessons learned
- Apply findings to Con Edison's project to leverage experience of others to improve all phases of the project
- Establish a peer utility group to use as an ongoing resource throughout the AMI project lifecycle

Prior to launching the benchmarking research effort, Con Edison considered the selection of peer utilities that would provide the optimal array of experiences to support its effort. Characteristics such as number of meters, customer characteristics, urban/mixed typology, geographic distribution, combination of electric and gas services, and status of AMI deployment were all considered.

The following peer utilities[12] participated in this study, which was conducted, April – June of 2015:

- Canadian Utility
- Eastern Utility
- Midwest Utility
- Southern Utility
- Texas Utility
- Western Utility

[12] Identities were masked at the request of participating utilities to protect confidentiality.

A three-phase research approach was used, which started with developing a standardized survey instrument for completion by the peer utilities. Following completion of the survey, Con Edison conducted follow up phone interviews with staff to either clarify or expand on input provided. In all cases, secondary research, such as Public Service Commission filings and utility websites was necessary to augment information provided directly by the peer utilities. As is typical with such studies, varying degrees of information were provided by the different utilities.

In summary, key takeaways can be categorized in three areas: change management, customer programs and technology.

Change management is often cited as a key enabler of a successful AMI project and the peer utilities recommended early planning for customer engagement and OCM. Community awareness and a preemptive public communications plan were essential to the success of the project. Governmental and external affairs also have a significant role, particularly in the early phases of building the network.

Customer acceptance of AMI is high as evidenced by very low meter “opt out” and resistance rates coupled with increasing customer recognition of benefits in controlling their use and costs. Average opt-out rates for peer utilities were less than 1% with reported data ranging from .0003% to 1%.

Our peer utilities noted that without AMI, new customer programs and newly designed “smart” rate plans would not have been possible, and particularly emphasized the role of smart meters in associated behavior change for both residential and commercial customers.

For residential customers, the Western Utility mentioned many benefits of AMI in terms of Demand Side Management (DSM) and Demand Response (DR). In addition to other factors, the program is supporting a broader statewide goal of achieving a 10% reduction in energy use based on DR program participation. They used an “opt-in” approach and currently report 130,000 enrolled in their Critical Peak Pricing (CPP) program.

With regard to technology, the surveys and interviews of the six benchmarked utilities indicated that a careful design and test of an integrated AMI solution can result in a reliable and valuable system with many benefits.

Each benchmarked utility recognized the importance of security and data privacy with an AMI solution and has implemented encryption, firewall protections and policies consistent with their individual security and privacy standards.

5. Benefit Cost Analysis (BCA)

The purpose of the benefit cost analysis (BCA) is to demonstrate through data-driven, scenario-based analysis the key costs and benefits of a full implementation of AMI throughout Con Edison's service territory.

The overall results of the evaluation are positive and the Company finds, most importantly, that customers would realize significant service enhancements. Furthermore, we contend that the customer, operational and financial benefits justify a full deployment of AMI. Con Edison will incur the following new expenditures as part of the project deployment: AMI metering equipment; a wireless radio frequency (RF) communications network; related information technology (IT) management and network systems; implementation services; and ongoing operational expenses. Over the 20-year evaluation period, assuming a six-year project life with a five-year meter deployment scenario, the Company would expect to invest, on a present value basis, $1,074 million in new capital and incur $552 million in operational costs to run the system. This results in a Net Present Value (NPV) of $1,080 million for the project. The cost and benefit results for a six-year AMI deployment scenario are shown in Table 3.

Table 3: Financial Highlights and Summary ($ in millions)

Business Case Component	Costs & Benefits (20 Year NPV)
A. Costs (20 Year NPV)	
O&M Expense for AMI System	$552
New Capital Investment for AMI System	$1,074
Sub-Total	***$1,626***
B. AMI Benefits (20 Year NPV)	
AMI Cost Reduction Benefits	$1,280
Customer and Company Benefits	$1,426
Sub-Total	***$2,706***
C. Total (20 Year Net NPV)	
Benefits Less Costs	**$1,080**
Discounted Payback Period*	***10***

***NPV and Payback calculated based on discount rate of 6.1% (Con Edison's WACC)**

As illustrated in Table 3, benefits over the twenty-year evaluation period exceed costs, resulting in a ten year payback. Benefits generally result from improved operational efficiencies, customer and Company benefits.

Upon completion of the installation of AMI meters, Con Edison projects that there will be an estimated $400 million of unrecovered book costs associated with the existing meters that will be replaced. For the reasons stated below, the Company does not propose any change to the timing for recovery of these costs as reflected in current rates (i.e., the Company would continue to recover these costs pursuant to the service lives established for this equipment).

In developing the AMI Benefit Cost Analysis ("BCA"), the Company did not include the remaining unrecovered cost of existing meters. In the Company's view, it is standard practice in developing a BCA to exclude previously-incurred "sunk costs," which have no effect on evaluating the net benefits of a new investment. The BCA is an analysis that compares incremental costs of the new investment to its incremental benefits. Absent the AMI project, customers would pay the full amount of the prudently incurred costs of existing meters and, therefore, the cost of an AMI project should not be viewed as higher simply because there is a portion of the costs of existing meters that remain to be recovered.

More important, including sunk costs in the determination of net benefits of a new investment could materially distort the BCA calculation and in some cases cause a project that is projected to produce net benefits for customers to be rejected. For example, if the Company has a project with projected incremental costs of $1 million, projected net benefits of $2 million, and sunk costs of $500,000, including sunk costs in the BCA calculation would still produce net benefits of $500,000, which would indicate the project should proceed. However, if the projected incremental costs were $1.5 million, and the projected net benefits $1.8 million, reflecting $500,000 of sunk costs in the net benefit calculation would show negative net benefits of $200,000 and indicate that the project should not proceed. Although in this instance, including the estimated sunk costs of meters in the BCA for AMI would not produce negative net benefits, (there would still be projected net benefits of approximately $680 million), including these sunk costs would, in the Company's view, significantly understate the projected value of this project to customers and establish an erroneous precedent for future BCAs performed by the Company.

From a societal perspective, this BCA achieves various goals for improving the customer experience and the operations of the electrical system. AMI impacts utility operations in a number of significant ways that will enable the Company to provide customers with improved service delivery that may *only be achieved through the use of AMI*. Detailed information on these benefits are addressed in the Customer Benefits section of this document (Section 2), and are summarized below:

Customer Benefits: Empowering Technology and Enhanced Customer Experience – Con Edison will be introducing programs and product offerings to empower customers and to improve upon their energy experience including the following:

- New advanced customer portal through which customers can:
  - Monitor energy usage in near real time
  - View more detailed and actionable information to help active energy consumers control usage and costs
- Enhanced customer programs offering:
  - Alternative rate structures to reward energy conservation, especially during periods of peak demand
  - REV demonstration projects to evaluate programs to improve customer engagement
  - Enhanced Demand Response programs
  - Enabling all customers to obtain wholesale market benefits from changing patterns

Customer Benefits: Enhancing Customer Service – The AMI solution will provide opportunities to enhance customer service and improve reliability in the following manner:

- Eliminates need for indoor meter reads, which increases customer convenience
- Offers customized choices in billing date that better fits with individual financial needs, pay cycle, or other considerations
- Greatly reduces estimated bills and disputes associated with estimated bills
- Provides new capabilities to engage low income customers to help manage usage and costs
- Provides easier service activation or transfer through remote meter service switch
- Enhances reliability
- Reduces frequency and duration of outages in emergency situations

Customer Benefits: Improving the Environment – AMI systems enable significant environmental benefits in three primary areas:

- Reduce GHG through Conservation Voltage Optimization (CVO)
- Reduce energy use through consumer behavior changes (e.g., expanded Demand Response Programs)
- Reduce vehicle emissions resulting from significantly reduced vehicle miles for:
  - Meter reading, service turn on/off and transfer
  - Avoided false outage service calls and efficiencies in service restoration following storms

Additional notable service delivery improvements include the following:

- **Enhanced meter reading accuracy:** The Company recognizes that our ability to efficiently provide accurate monthly bills to our customers is important to maintaining their trust in our capability to deliver affordable service. The enhanced meter reading accuracy that AMI provides is essential to fulfilling this customer obligation and represents a significant aspect of the AMI business case. Specifically, AMI's remote meter reading capability will significantly alleviate the need to estimate customer usage when meter reading personnel are physically prevented from reading meters.
- **Bill processing improvements**: Con Edison also recognizes that receiving a monthly bill is our customers' most tangible interaction with us as their energy provider. We recognize that bill reprocessing can negatively impact customer satisfaction. Consequently, reducing the instances of bill reprocessing is a major component of the AMI business case. Implementation of AMI will reduce the need to reprocess customer bills due to incorrect data entry.
- **Improved customer service and convenience:** AMI enables the Company to remotely perform meter connections and disconnections. This remote capability improves the customer experience by providing instantaneous service restoration. It also eliminates unbillable energy costs associated with accounts that are inactive or customers who have vacated their premises.

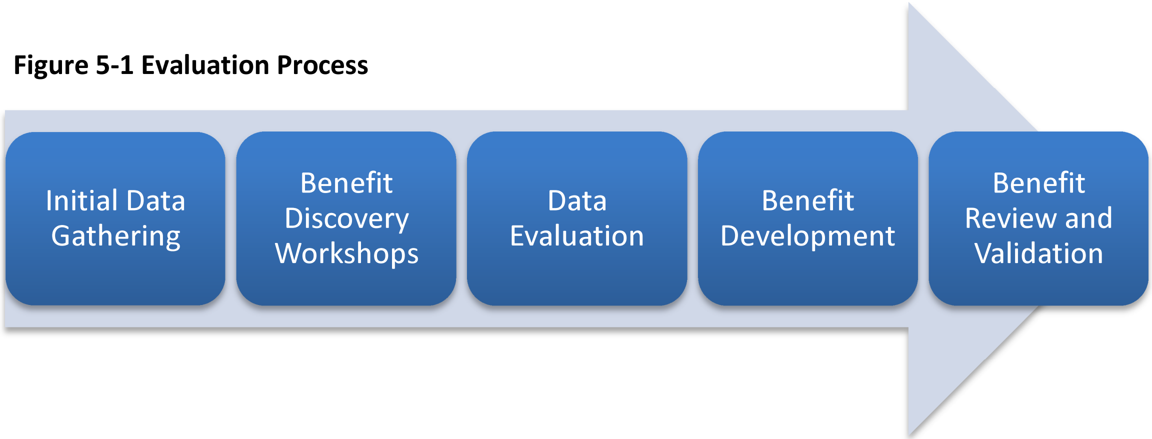
- **Outage management:** AMI will improve the Con Edison's ability to manage and locate outages within the distribution network. This near real-time intelligence will enable the Company to more efficiently target repairs and inform customers of estimated time to restoration, length of outage, and other critical information.
- **Risk reduction:** AMI may reduce the risk of outages in the event of an emergency. The Company's ability to remotely operate meter service switches through the AMI wireless communications network can enable remote load shedding to maintain grid stability.
- **Reforming the Energy Vision (REV)**: AMI directly enables future engagement with the Company's customers, a primary goal of the REV initiative of New York State. With the appropriate data systems and web presentment in place customers could leverage the interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. As the Company's program offerings continue to grow and evolve customers could leverage their consumption data to modify usage patterns. This may allow them to benefit from new offerings such as real-time pricing programs, expanded demand response program participation, and new "intelligent" grid opportunities such as peak load reduction and responsive load management applications. AMI empowers customers, providing choices for how they manage and consume electric energy; as a result, AMI may also help to protect the environment and lower overall energy costs for all of the Company's customers.
- **Conservation Voltage Optimization (CVO):** The AMI project will provide Company control room operators with voltage information at system service points, thus enabling system operation at optimal voltage levels. Operating the system at optimal voltages will reduce total energy consumption as well as associated power generation emissions. AMI will also provide engineers and planners with more granular data, enabling potential design and operational improvements.
- **Market preparedness:** AMI is also fundamental to the development of market systems that can leverage customer actual AMI usage date instead of predictive models. AMI data can provide key inputs to internal utility data models as well as to the NYISO.

5.1 BCA Evaluation Approach

This section describes the evaluation performed to validate Con Edison's AMI BCA to determine whether a future full scale AMI deployment within the service territory is reasonable and justifiable from a cost-benefit perspective.

Con Edison's AMI project team worked with key internal business groups to conduct the BCA (Figure 5-1). Over the course of the evaluation the team: (1) gathered data to refine the scope of the potential AMI system investment; (2) implemented a benefit discovery process to outline the evaluation approach; (3) evaluated the pertinent operational data and projections; (4) developed and finalized the key benefits for the BCA; and (5) validated the results.

Figure 5-1 Evaluation Process



The resulting benefits may be categorized as follows:

- Financial Benefits
  - **Customer and Company Benefits** – AMI will provide more accurate metering and enable reductions to costs that are currently socialized across all customers due to meter inaccuracy, theft of service, consumption on inactive meters (CIM), and bad debt. Additionally, AMI will enable system-wide conservation voltage optimization (CVO) resulting in significant energy savings for our customers. AMI will also make it possible for residential and commercial customers to enjoy the benefits of demand reduction programs and "smart home" rates that help them save money by changing energy usage behavior. Finally, AMI will improve outage management and the capability of the Company to identify outages within the electrical network, reducing both customer costs and lost revenue due to outages.
  - **Cost Reduction Benefits** – The AMI system will result in efficiencies in the form of reduced manual billing activities, as well as reduced Contractor and Company outage resource requirements.
- Other Benefits
  - **Risk Reduction Benefits** – The communications network will enable the remote control of meter service switches that allow the Company's Control Center operators to respond more effectively to system emergencies.
  - **Environmental and Societal Benefits** – A reduction in emissions from generating facilities will occur as the system gains efficiencies from CVO and customer participation in demand response, responsive customer integrated systems (e.g., electric vehicles, distributed energy resources, etc.) and Company programs. Detailed information on AMI's positive impact on environmental and societal benefits can be found in Section 2.
  - **Future Benefits** – The AMI network will provide the capability to integrate new sensor functions to improve operational awareness of system conditions. The AMI system will also support the development of future billing programs and market interactions.

5.2 BCA Benefits

The BCA is based on a series of benefits that provide value to customers. Many of these benefits are avoided costs. Each benefit was built from a detailed understanding of the proposed business process change that will impact the activity area. A key part of the evaluation was for each department's management team to develop a common set of assumptions around each relevant benefit and establish approaches to quantify those benefits.

5.3 Other Benefits: Cost Reduction Benefits

The following operational activities will benefit from AMI and lead to cost reductions:

- Meter Reading
- Field Services (e.g. turn-ons & turn-offs)
- Call Center
- Outage Management (e.g. mutual assistance expenses)
- Interval Metering
- Gas and Electric Meter Capital Replacement Avoided Costs
- Solar Site Metering
- System Retirement and Discontinued AMR Installation Program
- Other Operations Benefits

Each operation provides a benefit summarized in each section below.

5.3.1 Meter Reading

AMI will deliver measurable benefits by automating many meter reading functions. The benefit estimation includes:

- Reduced need for manual meter reading function
- Reduced need for meter reading support staff functions

5.3.2 Field Services

The Field Services labor savings estimate is largely attributable to the fact that all single phase residential meters will be equipped with a remote service switch which allows for remote meter connects and disconnects. While the Company will be required to make an attempt to physically contact a customer prior to disconnection due to non-payment, this remote disconnect capability will eliminate labor costs and "truck rolls" for:

- Scheduled turn-on activity
- All subsequent trips for disconnect due to access issues after initial attempt
- All Special Forces trips
- Scheduled disconnects not due to non-payment
- Most Replevin activity

While Con Edison is required to make an attempt to physically contact a customer prior to disconnection for non-payment, there remain a large number of trips associated with this process due to access issues.

5.3.3 Call Center

Integration of AMI with other Company systems and an overall increase of data accuracy can have an impact on Call Center Labor. After deployment is complete, AMI will reduce the number of estimated and reprocessed bills due to errors in manual meter readings. Customer calls associated with these issues will correspondingly be reduced.

5.3.4 Outage Management

The AMI system will improve outage identification and restoration efforts which will benefit customers as well as provide for cost savings. The outage management benefits realized through the deployment of an AMI system include the following:

- AMI will reduce costs for both mutual assistance (i.e. crews from neighboring utilities who assist with restoration) and the Company's restoration crews during major storms. Crews will be dispatched more efficiently and released in a timely manner following verification of service restoration. Nested outages will be more visible and easily rectified.
- The Company responds to a significant number of outage reports per year that are determined to be "false outages". These "false outages" are not associated with electric service being provided to the premise and instead require the services of an electrician to resolve an internal electrical problem. Currently, the Company must dispatch personnel to resolve each of these outage reports. Following the implementation of AMI, office personnel can determine power status at the meter and avoid a field visit.
- In addition to false outages, the Company responds to high voltage, low voltage, and flicker claims. Many of these calls will be eliminated through analysis of meter data. As a result of improved monitoring and measurement capabilities, real power quality problems may often be identified before a customer experiences an issue.
- By reducing the incidence of false outage and power quality items noted above, affected crews can respond more quickly to site safety issues. This results in a reduction of site safety expenses.
- More effectively managed outages are expected to improve CAIDI (Customer Average Interruption Duration Index) performance.

5.3.5 Interval Metering

The Interval Metering benefit is in part attributable to the elimination of communications costs associated with interval meters. It is also attributable to reduced labor costs for manually reading meters with malfunctioning communication lines.

5.3.6 Gas Meter Capital Replacement Avoided Costs

The Company has several types of gas meters that have been designated for replacement either due to inaccuracy or obsolescence. In most cases these meters are not capable of being retrofitted with AMI modules. As a result, the AMI project claims the benefit of the avoided cost for future replacement of these meters. The cost of replacing these meters is included in the overall project cost.

5.3.7 Electric Meter Capital Replacement Avoided Costs

The Company has a large population of electro-mechanical meters that as a result of age or service issues must be gradually replaced over time. The AMI project claims the avoided cost of replacing these electric meters over the next 20 years as a benefit since all of these meters will be replaced as part of the AMI project.

5.3.8 Solar Site Metering

The Company currently supports solar and other distributed generation sites through the installation of new electric meters that measure the power generated from the site. AMI metering will eliminate the need for the installation of this new meter. The AMI project claims the avoided cost of the installation of these additional meters over the next 20 years.

5.3.9 System Retirement and Discontinued AMR Installation Program

With the implementation of AMI, a number of programs and systems will be phased out. The AMI project claims the avoided cost of the funding of these programs and ongoing maintenance of the systems that will be retired. This includes the current Company program to replace meters with AMR enabled meters.

5.3.10 Other Operations Benefits

Billing improvements are anticipated based on expected increased billing accuracy and fewer exceptions, resulting in fewer billing complaints. Specifically, this benefit is based on:

- Fewer Account Investigation Lists (AIL's) due to increased accuracy
- Fewer complaints for high/estimated bills
- Fewer NYPSC complaints
- Automation of some manual billing processes

Granular AMI data will also enable improved engineering analysis of distribution system equipment and allow for optimization of capital expenditures.

The Meter Reading Support Systems benefit assumes that the equipment and associated systems to manage manual meter reading will be retired. The equipment considered in this evaluation includes:

- Handheld terminals and other systems for meter reading
- Vehicles
- Cell phones
- Vehicle fuel
- Vehicle maintenance

The Company will also realize savings in electric distribution transformer operations and maintenance (O&M), which will improve with the Company's capability of monitoring the load on the system (i.e., aggregating the meters that are served by a single transformer). This is an important benefit because these distribution transformers most often fail due to overloading. AMI provides the ability to monitor the loading of these transformers more precisely. Through engineering analysis resulting from the enhanced AMI data, some failures may be avoided. In avoiding these failures, costly emergency replacement and cleanup processes are also avoided, and the transformer asset itself may be preserved.

5.4 Customer and Company Benefits

The business case identifies the following Customer and Company-related financial benefits.

- Revenue Protection
- Meter Accuracy / Irregular Meter Condition (IMC)
- Conservation Voltage Optimization
- Bad Debt
- Inactive Meter/Unoccupied Premises
- Demand Side Management Expansion

Each Customer and Company-related feature provides a benefit summarized in each section below.

5.4.1 Meter Accuracy and Irregular Meter Condition (IMC)

Meter Accuracy and Irregular Meter Condition (IMC) captures the benefits realized in two areas. First, the Company has nearly two million electro-mechanical meters in service today. These meters typically under-register usage as they age.

The second portion of this benefit involves Irregular Meter Conditions (IMC). IMC's refer to errors in billing due to failed components, incorrect data entry, and other items. The Company will improve identification and resolution of many of these types of operational issues as part of the AMI project due largely to:

- Audited meter installations at all locations
- New business processes to minimize future data entry errors
- Usage analytics that will much more readily identify component failures

5.4.2 Revenue Protection

Revenue Protection (also known as theft detection) is another significant benefit attributable to AMI. Typically, utilities implementing AMI can expect to improve theft detection due to the increased monitoring and measurement capabilities. The Revenue Protection benefit estimate is based on the following assumptions:

- Industry organizations such as EPRI and EEI estimate that energy theft in the U.S. ranges from 1% to 3%.[13] This BCA assumes a conservative estimate of reducing theft by 0.25%.
- The Company will have much better usage visibility through the use of 15 minute interval data instead of monthly data. The analytics inherent in a Meter Data Management System integrated with AMI will improve the capability to detect meter tampering.
- The deployment process will identify many tamper situations that have previously gone unnoticed given the need to physically install new meters at each service location.
- A modern, solid state AMI meter is significantly more tamper-resistant than electro-mechanical meters and will provide "theft detection" alarms.

[13] International Utility Revenue Protection Association, Edison Electric Institute (2011)

5.4.3 Conservation Voltage Optimization (CVO)

CVO will enable the adjustment of the actual line voltage to a lower value, thus reducing the amount of energy consumed by our customers to power a given load. The Company currently utilizes a somewhat conservative voltage "profile" due to limitations in real-time information about the actual voltage in the system at any end point. AMI is an essential component to implementing CVO on the Company's system because it provides new voltage measurement capability at meters installed at all of our distribution system end points, providing control room operators with the data necessary for system operation at optimal voltage levels.

The "networked" nature of the Company's grid provides exceptional reliability and quality of service delivery capabilities, but also presents complex monitoring and control challenges. Most electrical grids throughout the world are radial in nature, meaning they hierarchically deliver power from generation to load through a series of wires at lower and lower voltages. Voltage sensors can be deployed at the endpoints of a radial system, and system operators can lower the system voltage at these specified end points, thereby regulating the voltage level in the system. However, since 86% of the Company's distribution system is constructed as a network grid (i.e., interconnected rather than radial feeders), determining the precise location of voltage low points is more complicated due to the dynamic nature of the grid. In order to reliably optimize system voltage levels, AMI is required to sense the voltages at our system end points. In comparison to other utilities, the Company's customers will be able to realize substantial CVO related benefits from AMI given the networked nature of most of the Company's distribution system.

A further complicating factor for CVO on the Company's system is the variety of customer loads behind the meter. Customer behavior may also impact the voltage with certain types of electrical equipment and DERs. Certain customer electronic equipment is also sensitive to real-time system voltage conditions and, as a result, when implementing system wide CVO it is important to maintain reliable and high-quality service through careful measurement of voltage conditions at system end points.

AMI will also provide engineers and planners with more granular data, resulting in design improvements that will further flatten out the voltage profile and enabling further reductions in energy consumption and emissions. For example, if AMI identifies a particular geographic area in the secondary network where the voltage is constantly lower than the rest of the network, then this area would become a "limiting" area for CVO optimization (i.e. the end-of-line). This situation is often caused by highly loaded mains that could be upgraded, or as an option, the voltage in the area could be lifted by changing out adjacent transformers with transformers with variable-taps (when they are ready to be changed). AMI provides the data necessary to understand and correct these types of engineering challenges which create real costs in the system. Upon correcting such an issue, the area voltage profile could once again be lowered, thus leading to additional energy savings and environmental benefits for customers and society at large.

Operating the system at optimal voltages will reduce total energy consumption as well as associated emissions produced during power generation. Leveraging the AMI system, CVO will allow the Company to reduce energy usage in the distribution grid and achieve an environmental impact of reducing CO_2 emissions in New York City and across New York State. With the implementation of AMI, the Company estimates a $346M NPV cost savings for the 20-year BCA analysis, of which $292M results from fuel savings and $54M is due to CO_2 reductions.

5.4.4 Bad Debt

When customers are unable or refuse to honor their billing commitments, the Company must eventually categorize this unrealized revenue as bad debt and "socialize" it across all of the Company's paying customers. AMI does not entirely eliminate bad debt. However, through the utilization of the remote disconnect switch, AMI can reduce the accrual of additional charges that occur between the time that the electric customer is eligible for disconnect until the time that the customer is actually disconnected.

5.4.5 Inactive Meter/Unoccupied Premises

Another AMI-enabled benefit concerns inactive meter or unoccupied premises. At any given time the Company estimates there are typically more than 100,000 premises where electric service remains connected although the account is inactive. AMI will eliminate the potential for this condition at the meter through automation by providing the capability to disconnect the electric service to vacant premises using AMI remote service switching. As a result, the Company can eliminate these unbillable energy costs and therefore reduce the subsequent costs that are currently socialized across the customer base.

5.4.6 Demand Side Management (DSM) Program Expansion

An analysis of the potential residential sector Demand Side Management program expansion enabled by AMI has been prepared by Nexant and is included in Appendix D. That analysis indicates that AMI enabled DSM for just the residential sector results in a benefit of $90.4 million (20 year NPV) to the Company over the 20-year BCA analysis. The Nexant report summarizes a benefit-cost analysis for the implementation of a specific time-varying rate offered to Con Edison's residential customers based on a variety of enrollment scenarios. The estimates provided in the Nexant report were based on empirical research from pilots and programs conducted elsewhere and may be conservative in that they do not factor in the potentially significant impact of enabling technologies on demand response nor do they consider impacts for non-residential customers or from energy savings (as opposed to capacity savings) that can occur when TVP is deployed.

5.5 Customer Service and Operations Benefits

AMI deployment results in several other customer engagement benefits that are not quantified as financial benefits. These benefits include the customer service enhancements and operational improvements that will enhance the overall satisfaction and experience of the customers. These benefits are summarized in Table 4.

Table 4: Customer Engagement Benefits

Customer Service Enhancements	With the appropriate data systems and web presentment, AMI can provide granular usage information to customers, enabling their understanding of usage patterns.
	Notification of unusual usage before a bill is issued may encourage customers to manage their consumption. This may increase customer satisfaction and avoid billing disputes.
	The system will provide flexible billing cycles due to the elimination of the physical meter reading routes. Customers may be able to choose a billing date that better fits with their financial needs, pay cycle, or other considerations.
	Outage metrics improve: The AMI system will result in faster and more reliable identification of outage locations. This may reduce outage duration and result in faster service restoration.
	AMI deployment will improve the accuracy of all meter reading. Automated meter readings and processing will eliminate manual data entry and visual meter reading errors, improving customer satisfaction.
Customer Focused Operations Improvements	The frequency of data collection will make meter reading data readily available within the billing windows. This will significantly reduce the need for estimated bills and may reduce high-bill complaints.
	The AMI system will provide data that can be leveraged to establish customer energy profiles for targeting marketing energy efficiency and demand response programs, and which could improve customer satisfaction.

5.6 Benefits Summary

Other than the customer benefits described in Section 2, the business case benefits are summarized in Table 5 below.

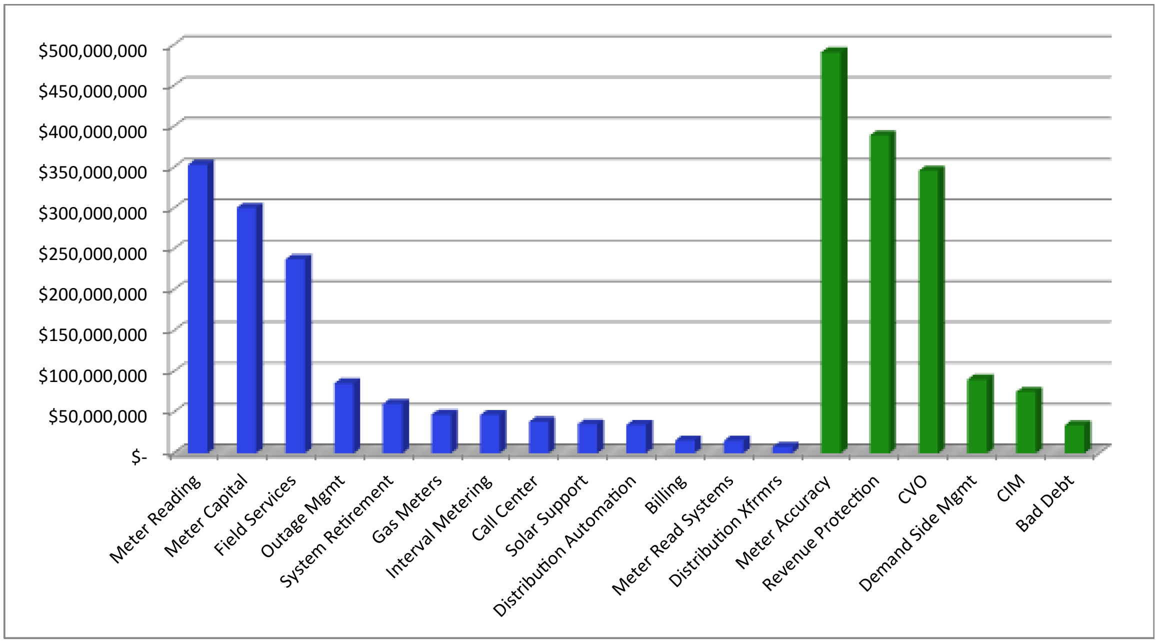
Table 5: Business Case Benefit Summary ($ in millions)

Benefit	Description	20 Year NPV (millions)	20 Year Cumulative Value (millions)
A. Cost Reduction Benefits			
Meter Reading Labor	An Operations and Maintenance (O&M) avoided cost.	$353	$740
Field Services Labor	O&M avoided cost.	$238	$500
Meter Capital	O&M Avoided cost.	$300	$562
Contractor and Company Outage Management Labor	O&M avoided cost.	$86	$183
Interval Metering	O&M avoided cost for data retrieval and processing as well as avoided capital cost for additional deployment of interval meters.	$47	$93

Benefit	Description	20 Year NPV (millions)	20 Year Cumulative Value (millions)
Gas Meters	O&M avoided cost for accelerated replacement for gas meters that have been flagged for accuracy or obsolete.	$47	$75
Call Center Labor	O&M avoided cost.	$39	$83
Distribution System Capital Expenditure Reductions	Deferral of capital expenses.	$35	$53
Billing Improvements	O&M avoided cost.	$16	$34
Meter Reading Support Systems	An avoided cost in replacement capital to upgrade these systems over time.	$16	$33
Distribution Transformers O&M Savings	An avoided cost due to reduced transformer failure and reduced O&M costs for transformer replacements.	$8	$17
Solar Support	Avoided cost to install a new meter in solar power locations.	$36	$68
System Retirement	Avoided cost for AMR and eventual retirement of some existing systems.	$61	$77
	Subtotal - Cost Reduction Benefits	$1,282	$2,518
B. Customer and Company Benefits			
Revenue Protection	A recovered cost due to reduced unaccounted for energy.	$388	$832
Meter Accuracy/Irregular Meter Conditions	A recovered cost due to reduced unaccounted for energy.	$491	$1,021
Conservation Voltage Optimization	An avoided cost due to energy savings, fuel and CO_2 reductions.	$346	$779
Bad Debt	An avoided cost due to more expedient processes for disconnect for non-payment.	$34	$71
Demand Side Management Expansion	Avoided costs of electric system investments due to wide scale demand reduction.	$90	$210
Inactive Meter/Unoccupied Premises	An avoided cost due to more expedient processes for inactive meters.	$75	$160
	Subtotal - Customer and Company Benefits	$1,424	$3,073
B. Total Business Case Benefits			
	Total Benefits	$2,706	$5,591

The aforementioned benefits are depicted in Figure 5-2 below.

Figure 5-2 Benefits (Present Value) Comparison



As a result of CVO, there are significant environmental savings in CO_2 emission reductions and fuel savings. With the implementation of AMI and its impact of CVO, the Company estimates a $346M NPV cost savings for the 20-year BCA analysis, of which $292M is due to fuel savings and $54M is CO_2 reductions.

Cost Reduction Benefits appear as blue bars whereas Customer and Company Benefits appear as green bars.

5.7 BCA Costs

The evaluation includes descriptions and estimates of four major cost elements associated with the AMI implementation and ongoing support. Costs are defined by general area (Meter, Communication system, IT Platform, and Management/other on-going Operations), by type (Capital and O&M), and by year (2016 – 2035). A summary of the 20-year cumulative nominal values for each of these cost categories is listed in Table 6.

Table 6: AMI Cost Summary ($ in millions)

Cost Category	Description	Capital Investment 20 Years	On-going O&M 20 Years	Total Expenditure 20 Years
AMI Meters	Physical AMI Meter (and supporting labor) to be installed at each premise/location	$747	N/A – Accounted for in Ongoing Operations	$747
AMI Communications	AMI Network Infrastructure to support communications from the AMI meters to “head end”	$103	$332	$434
IT Platform and Ongoing IT Operations	IT platform/systems to enable and support AMI system	$285	$618	$904
Project Management and Ongoing Operations	Management of project during deployment/ implementation and on-going AMI Operations	$149	$180	$329
	Total Costs	$1,284	$1,130	$2,414

5.8 Cost Model Assumptions and Limitations

BCA costs are based on vendor unit prices from actual vendor proposals in response to Requests for Proposals, industry experience, benchmarking and vendor contracts and expressed in nominal dollar terms.

The timing of each cost occurrence was reviewed and determined for each cost element. Many costs are scaled with meter deployment.

The deployment period is defined from 2016 to 2022, with a six year project expectation. The first year will involve deployment of the back office IT systems and infrastructure, followed by five years of communications system and meter deployment.

5.9 Cost Structure Assumptions

The cost structure refers to the assumptions made concerning roles and responsibilities for the Company’s resources and / or suppliers. These are summarized in Table 7. Changes to these assumptions may impact the resulting cost estimates.

Table 7: Implementation Support Services Assumptions

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Cost-Benefit Analysis
Meters, including hardware, shipping, handling, insurance, freight, testing, and warranty support	Vendor provided.	Pricing from vendor proposals, previous utility implementations and estimates provided to the Company by Vendors.
Initial core deployment meter installation work, including minor repair work, and call center appointment scheduling	Provided by consultants experienced with deployment costs and supplemented with field installation contractor estimates as appropriate.	Previous utility implementations, consultation with other utilities, and estimates from Vendors.
Ongoing meter replacement work	Based on industry norms and results at other utilities. Based also on the Company's experience with previous meter installation.	The Company's and consultant's experience with failure rates and for provisioning work order systems to manage fieldwork orders.
RF Communications planning and design and implementation	Vendor provided with support from consultants and the Company's territory knowledge.	Initial estimates from vendors along with consultant experience at other utilities.
RF Communication hardware requirements	Vendor provided.	Consultant experience and Estimates from Vendors.
Miscellaneous equipment for RF Communication hardware mounting requirements	Vendor provided.	Consultant experience. Estimates from Vendor.
Lease costs for some number of third party sites to mount RF equipment	Con Edison to manage, locate premises, negotiate agreements, and install.	Con Edison experience in maintaining its distribution system. Con Edison experience implementing DOE Smart Grid projects.
AMI Data Center Setup, Software acquisition, and on-going software maintenance	Con Edison to setup Network Operations Center (NOC).	Consultant experience. Vendor price estimates. Con Edison experience implementing IT NOC.
AMI System Operations	Con Edison to setup Network Operations Center (NOC).	Experience from other utilities. Vendor price estimates. Con Edison experience implementing IT NOC.

Cost Area	Business Structure Assumption for Implementation and On-going Operations	Basis of Cost Estimate Used in the Cost-Benefit Analysis
AMI System Software On-Going Maintenance	Con Edison AMI communication systems vendor to provide maintenance.	Pricing from vendor proposals, experience from other utilities.
AMI RF communication System field Maintenance	Con Edison personnel provided.	Vendor contract prices for replacement devices.
AMI RF communication "backhaul" WAN communication services	Public digital cellular communications provider such as Sprint or Verizon.	Vendor estimates.
IT MDMS Implementation Costs	IT vendors provided.	Pricing from vendor proposals. Consultant estimates. Vendor contract prices.
IT "middleware" applications and systems implementation costs	IT vendors provided.	Consultant experience. Vendor contract prices. Vendor price estimates.
IT systems integration work	IT vendors provided.	Pricing from vendor proposals. Consultant estimates. Vendor contract prices. Vendor price estimates.
IT hardware environment to support MDM and middleware	Joint Vendor to provide hardware. IT to install and operate.	Consultant estimates. Vendor contract prices. Vendor price estimates.
IT operations staff for ongoing MDM and Middleware systems	Con Edison personnel provided.	Consultant experience. Other utility experience.
Information systems costs to support new business practices associated with theft, tamper and other forms of unaccounted energy losses	Con Edison personnel and IT vendors jointly provided.	Consultant experience. Vendor price estimates.
AMI Operations	Con Edison personnel provided.	Consultant experience. Con Edison business planning.
Web-based energy information services	IT vendor provided.	Vendor price estimate.
Project Management Office (PMO)	Con Edison personnel and IT vendors jointly provided.	Vendor price estimates. Con Edison business planning.
Customer engagement	Con Edison personnel provided.	Con Edison business case estimates.
External communications	Con Edison personnel and IT vendors jointly provided.	Con Edison business case estimates.

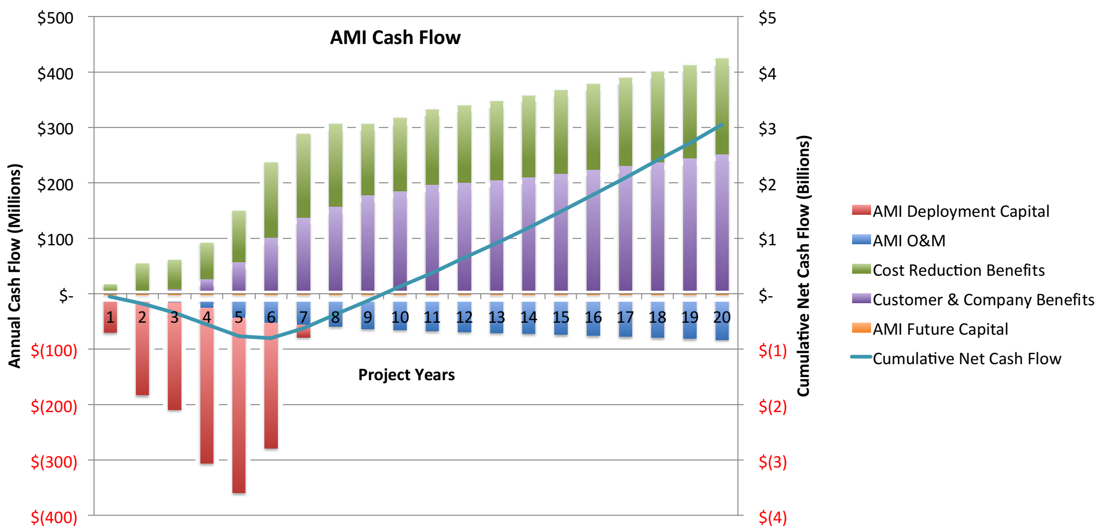
5.10 BCA Results

5.10.1 BCA Summary

The overall results of the AMI BCA are positive, with the proposed investment generating benefits exceeding costs over a 20 year horizon. The full scale AMI implementation would create substantial financial, operational, and environmental value for customers and provide the platform to achieve the benefits envisioned as part of the REV initiative.

The expenditure and benefit (revenues and avoided costs) patterns of the AMI investment are depicted in Figure 5-3.

Figure 5-3 Capital Investment and Ongoing Cost-Benefit Comparison



The BCA financial summary and BCA results are shown in Table 8.

Table 8: Financial Results and Summary

Business Case Component	Costs & Benefits (20 Year NPV)
A. Costs (20 Year NPV)	
O&M Expense for AMI System	$552
New Capital Investment for AMI System	$1,074
Sub-Total	***$1,626***
B. AMI Benefits (20 Year NPV)	
AMI Cost Reduction Benefits	$1,280
Customer and Company Benefits	$1,426
Sub-Total	***$2,706***
C. Total (20 Year Net NPV)	
Benefits Less Costs	***$1,080***
Discounted Payback Period*	***10***

***NPV and Payback calculated based on discount rate of 6.1% (Con Edison's WACC)**

5.10.2 Sensitivity Analysis

This AMI evaluation leverages findings, results, and lessons learned from AMI projects at other utilities as well as advice and information from consultants and vendors. Any analysis is incomplete without evaluating areas of uncertainty. There are many techniques available to perform such an analysis. In this report, a straightforward use of varying the input assumptions to determine output effects has been chosen.

Listed and described in Table 9 are the different data parameters (comprised of both cost and benefit factors) for the purposes of the sensitivity analysis. The approach identifies the impact on the base case of independent changes of each of the seven variables addressed, meaning that with each sensitivity analysis performed, only a single parameter is changed. Performing the sensitivity analysis in this manner helps identify the isolated impact on the business case as a result of changing a single variable.

Table 9: Summary of Sensitivities and Rationale

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
AMI Meter Cost	$90/electric meter	No Assumptions Made	The Base Case Value, which includes tax, has been validated by pricing from AMI vendors and therefore has little uncertainty remaining.
AMI Meter Installation Cost	$35/electric meter	$20 (favorable) $50 (unfavorable)	Based on initial RFP results, the model assumes a unit cost to install of $35 per meter.
Gas Module Cost	$56/gas module	No Assumptions Made	The Base Case Value, which includes tax, has been validated by pricing from AMI vendors and therefore has little uncertainty remaining.
Gas Module Installation Cost	$40/gas module	$25 / module (favorable) $50 / module (unfavorable)	Based on initial RFP results, the model assumes a unit cost to install of $40 per meter. A separate bid was issued for Tin Case Meter replacement.
Network Communications Equipment	$10 /electric meter	No Assumptions Made	The Base Case Value, which includes tax, has been validated by pricing from AMI vendors and therefore has little uncertainty remaining.
Network Communication Equipment Installation	$42 million	$30 million (favorable) $60 million (Unfavorable)	Based on initial RFP results.

Variable	Base Case Value	Sensitivity Analysis Assumption	Description and Rationale
Meter Accuracy Improvement	1.0%	1.4% (favorable) 0.6% (unfavorable)	This estimate is based on a recovery of 1.0% unaccounted for energy with improvement in accuracy of the nearly 2 million electro-mechanical meters still in service.
Revenue Protection Improvement	0.25% recovery	0.4% (favorable) 0.1% (unfavorable)	It is estimated that utilities have between 1% and 3% in energy theft. This benefit assumes that 0.25% will be recovered.
Servers and Storage	$24 million	$15 million (favorable) $40 million (unfavorable)	The systems being implemented require large numbers of servers and storage. It is likely that some infrastructure and storage will be cloud-based.
IT Costs (Capital)	Projected Value	25% decrease (favorable) 25% increase (unfavorable)	IT costs have been projected in some detail. However due to the variety of interfaces that must be developed, this cost may have some variability.
O&M Labor	Projected Value	50% decrease (favorable) 50% increase (unfavorable)	O&M labor is has been projected in some detail. Due to the complexity and scale of the project this cost may have some variability.
CVO	Projected Value	20% increase (favorable) 20% decrease (unfavorable)	The projected benefit is based on detailed long term projections.

5.10.3 Sensitivity Analysis Results

Table 10, Table 11, and Table 12 present the impact to the evaluation base case (6-year project) in terms of changes to costs, benefits, and overall net customer impact. Figure 5-4 presents selected sensitivity results graphically. The largest impact to the business case is the achievable increase in unaccounted for energy through better meter accuracy and better detection of theft. With regard to the cost components, the AMI electric meter, gas module, network infrastructure price, and installation costs are the key variables that may impact overall cost; however, as shown in the analysis below, they each have a relatively small impact on the overall NPV of the project.

Table 10: Sensitivity Analysis Results: Meter, Module, and Communications Installations

		Meter Installation		Module Installation		Comm. Installation	
		Favorable	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable
Business Case Component	**Costs & Benefits (20 Year NPV)**	**$20**	**$50**	**$25**	**$50**	**$30**	**$60**
A. Costs (20 Year NPV)							
O&M Expense for AMI System	$552	$552	$552	$552	$552	$552	$552
New Capital Investment for AMI System	$1,074	$1024	$1,125	$1,058	$1,085	$1,062	$1,093
Sub-Total	***$1,626***	***$1,576***	***$1,677***	***$1,610***	***$1,637***	***$1,614***	***$1,645***
B. AMI Benefits (20 Year NPV)							
AMI Cost Reduction Benefits	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280
Customer and Company Benefits	$1,426	$1,426	$1,426	$1,426	$1,426	$1,426	$1,426
Sub-Total	***$2,706***	***$2,706***	***$2,706***	***$2,706***	***$2,706***	***$2,706***	***$2,706***
C. Total (20 Year Net NPV)							
Benefits Less Costs	**$1,080**	**$1,130**	**$1,029**	**$1,096**	**$1,069**	**$1,092**	**$1,061**
Discounted Payback Period (WACC)	***10***	***10***	***10***	***10***	***10***	***10***	***10***

***NPV and Payback calculated based on discount rate of 6.1% (Con Edison's WACC)**

Table 11: Sensitivity Analysis Results: Servers and Storage, Meter Accuracy and Revenue Protection

		Servers & Storage		Meter Accuracy		Revenue Protection	
		Favorable	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable
Business Case Component	**Costs & Benefits (20 Year NPV)**	**$15M**	**$50M**	**1.40%**	**0.60%**	**0.4%**	**0.1%**
A. Costs (20 Year NPV)							
O&M Expense for AMI System	$552	$552	$552	$552	$552	$552	$552
New Capital Investment for AMI System	$1,074	$1,057	$1,098	$1,074	$1,074	$1,074	$1,074
Sub-Total	***$1,626***	***$1,609***	***$1,650***	***$1,626***	***$1,626***	***$1,626***	***$1,626***
B. AMI Benefits (20 Year NPV)							
AMI Cost Reduction Benefits	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280
Customer and Company Benefits	$1,426	$1,426	$1,426	$1,544	$1,309	$1,660	$1,193
Sub-Total	***$2,706***	***$2,706***	***$2,706***	***$2,824***	***$2,589***	***$2,940***	***$2,473***
C. Total (20 Year Net NPV)							
Benefits Less Costs	**$1,080**	**$1,097**	**$1,056**	**$1,198**	**$963**	**$1,314**	**$847**
Discounted Payback Period (WACC)	*10*	*10*	*10*	*10*	*10*	*10*	*11*

***NPV and Payback calculated based on discount rate of 6.1% (Con Edison's WACC)**

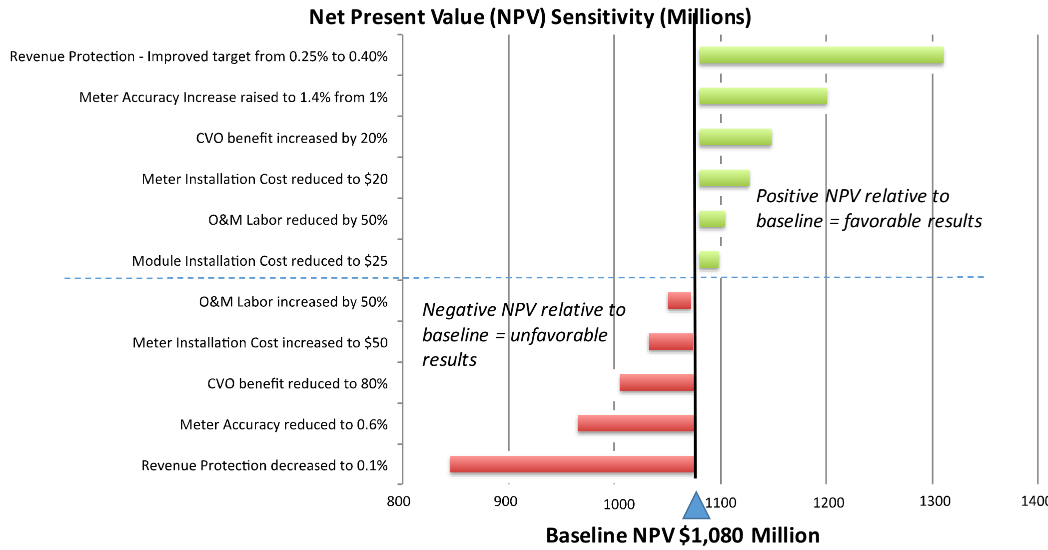
Table 12: Sensitivity Analysis Results: IT Costs, O&M Labor, and CVO

		IT Costs		O&M Labor		CVO	
		Favorable	Unfavorable	Favorable	Unfavorable	Favorable	Unfavorable
Business Case Component	**Costs & Benefits (20 Year NPV)**	**75%**	**125%**	**50%**	**150%**	**120%**	**80%**
A. Costs (20 Year NPV)							
O&M Expense for AMI System	$552	$552	$552	$530	$574	$552	$552
New Capital Investment for AMI System	$1,074	$1,062	$1,086	$1,074	$1,074	$1,074	$1,074
Sub-Total	***$1,626***	***$1,614***	***$1,638***	***$1,604***	***$1,648***	***$1,626***	***$1,626***
B. AMI Benefits (20 Year NPV)							
AMI Cost Reduction Benefits	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280	$1,280
Customer and Company Benefits	$1,426	$1,426	$1,426	$1,426	$1,426	$1,495	$1,357
Sub-Total	***$2,706***	***$2,706***	***$2,706***	***$2,706***	***$2,706***	***$2,775***	***$2,637***
C. Total (20 Year Net NPV)							
Benefits Less Costs	**$1,080**	**$1,092**	**$1,068**	**$1,102**	**$1,058**	**$1,149**	**$1,011**
Discounted Payback Period (WACC)	***10***	***10***	***10***	***10***	***10***	***10***	***10***

***NPV and Payback calculated based on discount rate of 6.1% (Con Edison's WACC)**

The chart below shows the 10 most impactful variations of the sensitivities listed above.

Figure 5-4 Sensitivity Analysis Chart



6. Conclusion

The AMI infrastructure contemplated is foundational to facilitating enhanced delivery of various customer programs and utility best practices, including: demand response initiatives; net-metering distributed energy resources (DERs); future distribution system asset monitoring; measurement and control; responsive load control and demand response (DR) opportunities; and numerous other possibilities. The energy distribution system of the next twenty years will be formed by utilities and service providers who are most capable of delivering next generation smart grid capabilities, such as those defined by the Reforming the Energy Vision initiative. Distributed System Platforms (DSPs) face a future in which they will have reliability-driven responsibilities to enable distributed markets, accommodate technology innovations, and engage third-party energy service providers. Ultimately DSPs will play a critical role in developing products and services that will inform and shape our idea of energy systems and their benefits to society. The Company considers AMI a foundational component of this evolution, enabling precise measurement and potential control capabilities throughout the system. Without AMI, a utility may not fully engage in the many service offerings, products, and markets that are envisioned in the REV future.

The Company has determined that a full scale advanced metering infrastructure implementation best meets our customers' current and future needs, facilitates retail access programs and will be the single most effective means of enabling the energy vision and marketplace envisioned in the Commission's REV initiative. The Company evaluated multiple alternatives to a fully enabled AMI rollout and determined that none of the alternatives would meet REV objectives in a cost effective manner or create a cybersecure communication infrastructure to support the current and future functionality that will be realized by AMI.

In summary, the Company requests that the Commission find the following:

- The AMI business case presents favorable customer-centric and financial benefits relative to costs and enables REV initiatives.
- The Company should proceed with implementation of AMI to all its customers as proposed in this Plan.

Appendix A. AMI System Requirements

NYPSC AMI Minimum Functional Requirements

(a) AMI systems must be compliant with all applicable ANSI standards, Commission regulations, and Federal standards, such as FCC regulations.

(b) AMI systems must provide net metering.

(c) AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with the auxiliary device if it is the only means of a visual read of consumption data.

(d) AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.

(e) AMI meters must have sufficient on-board meter memory capability to ensure meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.

(f) AMI systems must have the ability to provide customers direct, real-time access to electric meter data. The data access must be provided in an open non-proprietary format.

(g) AMI systems must have the ability to remotely read meters on-demand.

(h) At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.

(i) AMI systems must have two-way communications capability, including ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.

(j) AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network (HAN) to provide direct or customer-activated load control.

(k) AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.

(l) AMI systems must have the following security capabilities:

(i)Identification - uniquely identify all authorized users of the system to support individual accountability;

(ii)Authentication – authenticate all users prior to initially allowing access;

(iii)Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated;

(iv)Integrity – prevent unauthorized modification of data and provide detection and notification of unauthorized actions;

(v)Confidentiality - secure data stored, processed, and transmitted by the system from unauthorized entities;

(vi)Non-repudiation - provide proof of transmission or reception of a communication between entities;

(vii)Availability - ensure that information stored, processed and transmitted by the system is available and accessible when required;

(viii)Audit - provide an audit log for investigating any security-related event; and

(ix)Security Administration – provide tools for managing all of the above tasks by a designated security administrator.

Con Edison Functional and Performance Requirements

The Company has identified both functional and performance requirements for the AMI business case as outlined in the table below:

Table A.1 – AMI Base System Specifications

Requirement	Base System Specification
Regulatory	Must comply with New York PSC Minimum Requirements for AMI
Electric Metering	Meters must support TOU rates, demand calculations, net metering, reactive power assessment, remote configuration, and downloadable firmware; must support remote service switch for residential meters; real time and scheduled reporting of alarms and alerts
Gas Metering	Meters must support hourly interval data, CCF, for C&I meters - CCF Uncorrected, pressure, and temperature

Table A.2 – AMI Detailed Specifications

Requirement	Performance Scenario 1	Performance Scenario 2	Performance Scenario 3	Remarks
Electric Meter register reads (kW) Number of Commercial (C) meters - 300,000 Number of Residential (R) meters - 3,250,000	C - 5 min interval R - 15 min interval	C - 5 min interval R - 15 min interval	C - 5 min interval R - 15 min interval	Interval reads at these frequencies will support future TOU programs Note- meter interval configuration can be changed to shorter intervals from AMI head end
Conservation Voltage Optimization (CVO)	175,000 meters– voltage reading every 5 minutes	175,000 meters – voltage reading every 5 minutes	175,000 meters – voltage reading every 5 minutes	All meters will have high/low voltage threshold alerts which will be sent in real-time when threshold is exceeded
Electric Customer Data Presentment	100 % of meters (3.5 million electric meters) to be displayed near real time (15 minute lag)	20% of meter reads (700,000 meters) displayed near real time (15 minute lag)	Data will be displayed on portal next day	Determination of selected option to be made following RFP's for Meters/ Communications system equipment and Installation
System Performance - Interval Reads	99.50%	99.50%	99.50%	For both gas and electric meters
System coverage	100%	100%	100%	For both gas and electric meters
Gas Meter register reads	Hourly gas interval reads	Hourly gas interval reads	Hourly gas interval reads	1.2 million gas meters
Gas Customer Data Presentment	Data will be displayed on portal next day	Data will be displayed on portal next day	Data will be displayed on portal next day	

Appendix B. Definition of Terms

Term	Definition
Advanced Metering Infrastructure	Advanced Metering Infrastructure (AMI) is the term denoting electricity and gas meters that measure and record usage data at a minimum in hourly intervals, and provide usage data to both consumers and energy companies at increased frequencies. AMI meters are "smart" and have additional interoperability features, such as 2-way metering, communications enablement with customer equipment, and other capabilities.
CAIDI	CAIDI refers to Customer Average Interruption Duration Index. CAIDI is a measure of duration that provides the average amount of time a customer is without power per interruption of service.
Conservation Voltage Optimization	Conservation Voltage Optimization (CVO) is a technique for improving the efficiency of the electrical grid by optimizing voltage on the feeder lines that run from substations to customers.
Consumption on Inactive Meter	Consumption on inactive meter refers to the metered electricity that is generally socialized over all of a utility's customers when there is no customer on record to bill for the electricity consumed.
Demand Response	Demand response (DR) programs are incentive-based programs that encourage or direct electric power customers to temporarily reduce their demand for power at certain times in exchange for a reduction in their electricity bills or other incentive. Customer-controlled reductions in demand may involve actions such as curtailing load, operating onsite generation, or shifting electricity use to another time period.
Distribution System	Distribution system refers to the portion of the facilities of an electric system that is dedicated to delivering electric energy to an end-user, rather than transmission, which transports energy between bulk electrical system components.
Methane	Methane is a colorless, flammable, odorless hydrocarbon gas which is the major component of natural gas. As a component of natural gas, it is often monitored in closed spaces to alert distribution operators to potential leaks.
Replevin	Replevin is a procedure which permits a court to determine which of the parties to a legal action has a superior right to possession of property in dispute. Replevin is an effective and efficient pre-trial process by which a utility achieves termination of service and recovers a meter.

Appendix C. List of Abbreviations

AIL	Account Investigation Lists
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CBM	Condition Based Monitoring
CIM	Consumption on inactive meter
CSR	Customer Service Representatives
CVO	Conservation Voltage Optimization
DER	Distributed Energy Resources
DR	Demand Response
DSP	Distributed System Platform
EEI	Edison Electric Institute
EIA	US Energy Information Administration
EPRI	Electric Power Research Institute
FMS	Field Meter Services
HV	High Voltage
IMC	Irregular Meter Condition
IT	Information Technology
LV	Low Voltage
MA	Mutual Assistance
MHP	Mandatory Hourly Pricing
NOC	Network Operations Center
NPV	Net Present Value
NYISO	New York Independent System Operator
O&M	Operations and Maintenance

OMS	Outage Management System
PJM	PJM Interconnection LLC
PMO	Project Management Office
REV	Reforming the Energy Vision
RF	Radio Frequency
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SMUD	Sacramento Municipal Utility District
UB	Uncollectible Balances
UFE	Unaccounted for Energy
WACC	Weighted Average Cost of Capital

Cost Effectiveness of Time-Varying Pricing with Advanced Metering Infrastructure in CECONY Territory

June 15, 2015

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1 Executive Summary

Consolidated Edison Company of New York (CECONY or the Company) has proposed to implement advanced metering infrastructure (AMI), which will provide opportunities to improve economic efficiency and support the goals and objectives of New York's Reforming the Energy Vision (REV) by offering time-varying pricing (TVP) options to consumers. This report documents analysis conducted by Nexant to estimate the net benefits associated with selected scenarios in which TVP is offered to all residential customers. The analysis assumes that both full service and retail access customers are treated the same with respect to offers of TVP. Net benefits are estimated based on five pricing scenarios that differ with respect to assumed acceptance rates, enrollment strategies (e.g., opt-in and default, or opt-out) and targeting strategies (e.g., all customers versus high use customers). The two low opt-in scenarios assume an enrollment rate of 5% applied to all customers in one scenario and applied to the top two quintiles of residential customers, based on annual usage, in the other scenario. The two high opt-in scenarios are similar but assume a 15% opt-in rate. The default scenario assumes a 10% opt-out rate.

The chosen scenarios, and the analysis associated with each, are meant to be illustrative of what might be achievable in terms of net benefits using the conventional total resource cost (TRC) metric and the specific set of assumptions associated with each scenario. These scenarios do not represent all the potential pricing options that would be enabled by AMI and are not meant to suggest what CECONY should or would do in terms of pricing strategy once AMI is fully deployed. Nor are the costs underlying each scenario meant to accurately reflect what CECONY's costs would be if the Company implemented a specific scenario. Having said this, the input values underlying the analysis are far from arbitrary. The data and assumptions used here are based on evidence from pricing pilots and programs implemented by other utilities combined with load data and other key inputs that are specific to CECONY's customer population.

This analysis estimates the net benefits associated with a specific TVP tariff offered to residential customers. The chosen tariff is a combination time-of-use, critical peak pricing (TOU-CPP) rate. Under this tariff, prices vary across peak and off-peak periods on all weekdays. On most days, the peak-to-off-peak price ratio is relatively modest (roughly 1.7 to 1). On 10 days a year, on average, referred to as CPP event days, the price ratio is much higher (roughly 14 to 1).[1] These high CPP prices drive significant demand reductions on CPP days which, in turn, produce significant benefits in the form of avoided generation and distribution capacity investments.[2]

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[1] CECONY's SCE1 Rate III structure has a summer ratio of roughly 14 to 1 for the delivery portion of the rate.

[2] The price ratio is a key driver of demand response. The higher the price ratio, the greater the demand reduction during peak periods, although the relationship is not linear. Empirical evidence indicates that the incremental load reduction for a given percent increase in the peak-to-off-peak price ratio falls as the price ratio increases above a certain threshold. For a summary of the empirical evidence on this issue, see A. Faruqui and S. Sergici. *Arcturus: An International Repository of Evidence on Dynamic Pricing.* In D. Mah et al. (eds.), *Smart Grid Applications and Developments,* Green Energy and Technology, DOI: 10.1007/978-1-4471-6281-0_4, © Springer-Verlag London 2014.

1.1 Cost-Effectiveness Results

Table 1-1 summarizes the cost effectiveness analysis for each of the five enrollment scenarios that are analyzed. As seen, the load impacts resulting from implementation of the specific TOU-CPP tariff analyzed here over the 20 year forecast horizon produce benefits ranging from a low of roughly $38 million in present value for the targeted, low opt-in scenario to a high of $625 million for the default scenario. The present value of benefits for the two targeting scenarios is roughly two-thirds of the value estimated for the non-targeted scenarios. The estimated costs of implementing TVP rates for each scenario over 20 years range from a low of roughly $29 million to a high of $193 million in present value.

Table 1-1: Cost-Effectiveness Results

Enrollment Scenario	Targeting Strategy	# Enrolled Customers	PV Benefits ($M)	PV Costs ($M)	PV Net Benefits ($M)	B/C Ratio
Opt-in Low (5%)	None	143,424	$55.5	$44.2	$11.4	1.26
	Top 2 Usage Quintiles	59,717	$37.7	$29.2	$8.5	1.29
Opt-in High (15%)	None	430,270	$166.6	$76.6	$90.0	2.17
	Top 2 Usage Quintiles	176,148	$113.1	$46.4	$66.7	2.44
Default (90%)	n/a	2,581,622	$624.7	$193.1	$431.6	3.24

Net benefits, the primary measure of cost-effectiveness, are positive in all scenarios and range from a low of $8.5 million for the opt-in, low scenario with targeted marketing to a high of $432 million for the default scenario. The benefit-cost ratio ranges from 1.26 to 3.24. An aggressive and effectively marketed opt-in program that achieves a 15% enrollment rate is estimated to produce significant net benefits of roughly $90 million in present value based on the tariff and assumptions analyzed here. Net benefits for the default scenario are almost five times larger than for the high opt-in scenario.

The estimates summarized above may significantly understate the net benefits that are achievable from AMI deployment. The analysis does not include the potential impacts from non-residential customers nor does it factor in the substantial increases in load reductions that can be achieved when time-varying rates are combined with enabling technology such as smart thermostats and energy management systems. As these technologies penetrate the market or are driven into households and businesses through utility-sponsored programs, demand reductions from time-varying rates could be much larger.

2 Introduction

CECONY's plans to implement advanced metering infrastructure (AMI) will provide opportunities to improve economic efficiency and support the goals and objectives of New York's Reforming the Energy Vision (REV) by offering time-varying pricing (TVP) options to consumers. More than four decades of empirical research has shown that many consumers can and will enroll on TVP tariffs and will reduce usage during higher-priced periods relative to usage under tariffs where prices do not vary across the hours of the day, days of the week and seasons. TVP can lead to significant reductions in costs over time by reducing the need for high-cost peaking generation, reducing market clearing prices in wholesale markets or reducing or delaying distribution capacity investments.

Historically, a major impediment to customer participation in TVP programs has been the high cost of metering on an individual customer basis. This is especially true for mass market consumers such as residential households and small commercial businesses. If CECONY's AMI application is approved, the new metering platform will provide low cost opportunities for consumers to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply and delivery. In the recent New York Public Service Commission Order Adopting Regulatory Policy Framework and Implementation Plan (February 26, 2015), the Commission indicates that "REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale,…Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid." (p. 11) Although some believe these goals can be achieved without full scale, utility deployment of AMI, we at Nexant and CECONY fail to see how many of REV's primary objectives, and especially those summarized above, can be achieved in the absence of full-scale deployment of AMI.

This report documents analysis conducted by Nexant to estimate the net benefits associated with selected scenarios in which TVP is offered to CECONY's residential customers. The chosen scenarios, and the analysis associated with each, are meant to be illustrative of what might be achievable in terms of net benefits using the conventional total resource cost (TRC) metric and the specific set of assumptions associated with each scenario. These scenarios do not represent all of the potential pricing options that would be enabled by AMI and are not meant to suggest what CECONY should or would do in terms of pricing strategy once AMI is fully deployed. Nor are the costs underlying each scenario meant to accurately reflect what CECONY's costs would be if they implemented a specific scenario. Having said this, the input values underlying our analysis are far from arbitrary. The data and assumptions used here are based on evidence from pricing pilots and programs implemented by other utilities combined with load data and other key inputs that are specific to CECONY's customer population.

2.1 Study Scope

The analysis presented here pertains only to residential consumers. As such, it understates the total benefits that may be achievable by offering TVP to small and medium business consumers. The focus on residential consumers is both practical and logical. The practical aspect of this focus is that there is much more empirical evidence concerning price responsiveness and enrollment of residential consumers on TVP tariffs than there is for small and medium businesses. Other than in California, where all non-residential customers will be on mandatory TVP pricing by the end of 2016, there is relatively little evidence from pilots or programs concerning the impact of voluntary, opt-in tariffs for small and medium businesses.

A logical reason why the focus of this analysis is on residential consumers is that full scale deployment of AMI is essentially a necessary condition for wide-scale enrollment of residential consumers onto TVP tariffs. Full deployment of AMI is not as critical for offering TVP to many business customers, especially medium commercial customers, because they can be offered TVP cost effectively using non-communicating interval meters and manual meter reading. Put another way, the cost effectiveness of TVP for residential consumers is much more reliant on full AMI deployment than it is for non-residential consumers. That being said, if AMI is fully deployed, it will be much easier and more cost-effective to offer TVP to small and medium businesses, which could produce substantial net benefits depending on what rates are offered, how aggressively they are marketed, and whether or not the REV vision of distribution level markets is as successful as hoped. Given this, the net benefit estimates presented here should be considered a lower bound of what might be possible compared with a scenario in which TVP is also offered to small and medium businesses in addition to residential consumers.

Another reason why the benefit estimates presented here should be considered a lower bound is that the analysis does not incorporate the incremental impact on demand response from the use of enabling technologies such as smart thermostats or utility owned demand response equipment. Numerous studies[3] show clearly that, at least for households with central air conditioning, smart thermostats and utility owned load control can substantially increase demand reductions obtained through TVP compared to instituting TVP without technology. Of course, purchasing and installing technology solely for the purpose of increasing peak period load reductions in conjunction with TVP can be costly and these costs must be weighed against the incremental benefits. However, with the recent interest of consumers in purchasing smart thermostats because of their additional functionality, such as mobile access and energy management capabilities, utilities will be able to capture these larger benefits at lower cost by partnering with consumers and technology firms to take advantage of the naturally occurring market penetration of these technologies. Indeed, many of the discussions currently underway through the REV market design and technology platform working groups imagine a “prices to devices” world where enabling technology is widespread and consumer preferences can be reflected in energy management systems that automate behavioral response to dynamic price signals. If this vision is realized, the magnitude of demand reductions and resulting benefits could be substantially larger than anything suggested by the analysis presented here.

Yet another reason why the net benefits presented here may be low relative to what could be achieved through full scale deployment of AMI concerns the potential impact of enhanced information feedback to consumers that is possible once interval usage data is widespread. There have been numerous studies[4] concerning the behavioral conservation impacts of

[3] See Faruqui and Sergici cited previously.

[4] For a useful overview, see *Residential Electricity Use Feedback: A Research Synthesis and Economic Framework.* EPRI, Palo Alto, CA: 2009. 1016844.

enhanced information such as normative comparisons through home energy reports, weekly usage or bill alerts (with or without goal setting), and real-time feedback through in-home display devices or IP-addressable devices that connect personal computers and mobile devices with meters. The empirical data from home energy reports studies throughout the country suggests monthly savings of 0.5% to 2.5% from this type of feedback.[5] Savings from AMI based information feedback such as IHDs or usage alerts have yet to be established conclusively, often due to poor research design of pilot studies or external validity concerns when trying to extrapolate results to non-study populations. Nevertheless, there is significant interest in this topic and the many studies currently underway in the industry may identify cost-effective information feedback methods and devices that will enhance the benefits achievable from AMI information in the presence of TVP.

In short, the analysis presented here is conservative and may represent only the tip of the iceberg in terms of the benefits that could be achieved through large scale deployment of AMI combined with new pricing strategies and, ultimately, new technology applications and market designs that may arise from REV. As seen below, even with the narrow focus of this study and the relatively conservative assumptions that we have deliberately made, positive net benefits are achieved by offering TVP to residential consumers for all of the pricing scenarios examined.

2.2 Study Time Frame

The analysis presented here covers a 20 year period starting in 2020, with the first year being a prelaunch period. It is assumed that all AMI meters are in place throughout the CECONY service territory by the first year of the analysis and that new TVP tariffs will be offered beginning in 2021. As a result, all startup costs associated with the TVP tariffs are incurred in the prelaunch period, but no benefits are realized because the new tariffs are not yet available.

The analysis also treats all residential customers alike, regardless of whether they are full service or retail access customers. We have made no attempt to forecast changes in the CECONY population, base rates or avoided costs between 2015 and the year in which all AMI meters should be in place (2021). Put another way, the analysis assumes that the characteristics of the CECONY system (including customers) in 2021 are the same as they are today. Predicting how these characteristics might change over the next six years, especially in light of the substantial changes in certain characteristics such as avoided distribution capacity needs and costs in light of the REV and the increasing penetration of distributed resources other than TVP, involves too much uncertainty at this time to accurately incorporate into the analysis.

As indicated above, the analysis presented here assumes that no one is offered TVP prior to when all meters are in place and no startup costs are incurred until the year prior to offering the new rates. An alternative approach that has been employed elsewhere (PG&E for example) to market the new rates to a customer as soon as they receive a new meter. Using this approach allows benefits to be captured sooner, but will incur startup costs sooner as well.

[5] See Hunt Allcott. *Site Selection Bias in Program Evaluation.* Working Paper. New York University Department of Economics. February 13, 2015.

2.3 Pricing Scenarios

The benefits of TVP are primarily a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g., prices and hours in each rate period). These factors drive the change in usage by rate period which, in turn, drives the benefits that can be achieved in the form of avoided capacity investments and reductions in fuel costs or market clearing prices. The analysis examines the net benefits associated with a single rate option. Benefits would differ with differences in the structure of the rates and the price levels that apply by rate period.

Given that customer enrollment and customer loads are two of the key drivers of benefits (and costs, as discussed later), we have analyzed the net benefits of TVP for five pricing scenarios in which enrollment and customer loads vary. These five scenarios can be summarized as follows:

1. **Opt-in Enrollment, Low, No Targeting:** This scenario represents a case where CECONY would actively market TVP pricing and achieve a 5% enrollment rate over a two year period and then maintain that level of enrollment over the 20 year forecast horizon that underlies all of the analysis. The TVP rate would be marketed to all residential customers using a combination of mass media and direct mail marketing.

2. **Opt-in Enrollment, Low, Targeting:** This scenario is similar to Scenario 1, except that the marketing would be targeted at residential consumers in the two highest usage quintiles based on annual consumption. Prior studies[6] show that high usage customers, many of whom own central air conditioning, produce significantly greater demand reductions than low usage customers. While high use customers are harder to attract onto TVP tariffs because they are less likely to be structural winners[7] than lower usage customers (and therefore may have require higher marketing costs to attract), targeting can be more cost-effective than programs that are offered to all consumers, some of whom deliver very low or no demand reductions. This scenario assumes that 5% of targeted customers enroll on TVP rates.

3. **Opt-in Enrollment, High, No Targeting:** This scenario is similar to Scenario 1 except that the assumed enrollment rate is 15% rather than 5%. Enrollment rates of 15% or higher have been obtained by a number of utilities, including the Sacramento Municipal Utility District (SMUD)[8] in a two-year pilot where enrollment rates were between 15% and 19% for various opt-in tariffs. Salt River Project and Arizona Public Service have roughly 25% and 50% of their residential population enrolled on TVP rates, respectively.

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[6] See Stephen S. George and Ahmad Faruqui. *Impact Evaluation of California's Statewide Pricing Pilot.* Final Report, March 16, 2005.

[7] A structural winner is a consumer whose bill will fall by going onto a TVP tariff even if they don't change their usage pattern. For revenue neutral TVP tariff designs, structural winners are those consumers who use less during peak periods than the average consumer.

[8] See Stephen S. George, Jennifer Potter and Lupe Jimenez. *SmartPricing Options Final Evaluation.* SMUD. September 5, 2014.

Marketing and customer acquisition costs are significantly higher for this scenario compared with Scenario 1, but so are the benefits.

4. **Opt-in Enrollment, High, Targeting:** Similar to Scenario 2, this scenario targets the top two quintile usage segments and achieves an enrollment rate of 15%.

5. **Default Enrollment:** The final scenario assumes that all residential consumers are offered TVP on an opt-out basis. In this scenario, the TVP rate is still voluntary, not mandatory, but the "nudge principal" of moving consumers to a new tariff unless they proactively opt-out is applied. SMUD tested this approach in their pricing pilot and found that very few consumers chose to opt-out and, importantly, almost no one complained about being placed on a time-varying rate. While the average load reduction per customer was lower for default enrollment compared to opt-in enrollment, the aggregate demand reduction was much greater for the default option given the much higher enrollment rate. This scenario assumes 10% of consumers opt-out and return to a non-time-varying rate option.

All of the above scenarios are based on TVP, not on performance based options such as peak time rebates (PTR). PTR is an alternative to TVP that pays consumers to reduce usage during high demand periods rather than charge higher prices during peak periods and lower prices during off-peak times. PTR has been described as a "no loser" or "carrot only" pricing option compared with the "carrot and stick" TVP options. PTR has been tested in numerous pilots and has been deployed on both an opt-in and default basis.[9] Given its "no loser" nature, regulators and utilities are much more willing to deploy PTR on a default basis than they are willing to deploy TVP and several utilities have done so in the last several years, including BG&E, Pepco, SCE and SDG&E.

Despite its political appeal, PTR has an inherent shortcoming that can lead to significant payment error and, in the case of default PTR, significant overpayment for the demand reduction that is actually obtained. This fact led to a rapid change in policy at SDG&E and SCE, who switched to an opt-in PTR program after offering default PTR for two years. With opt-in PTR, payment error still exists for almost all customers but over and under payments can offset each other so that total payments are more in line with actual load reductions.

The flaw in PTR programs comes from the way in which incentive payments are calculated. PTR payments are based on the difference between an individual customer's metered load during the event period and an estimate of what that customer would have used during the same period had they not received the PTR offer. The estimate of what an individual customer would have used is referred to as a baseline value or reference load. Baseline estimates typically rely on simple algorithms such as peak period usage on the highest 3 out of the prior 5 days, or the average over the 10 prior, non-event days. However, even more sophisticated

[9] For an overview of prior studies, see Stephen S. George. *Assessment of a Peak Time Rebate Pilot by Oklahoma Gas & Electric Company.* Oklahoma Corporation Commission Staff Report. November 2, 2012.

methods such as regression analysis are inherently inaccurate for individual customers and individual days, especially for residential consumers.[10]

The problem with baseline estimation is that an individual customer's usage varies significantly from day to day, but this fluctuation often has little to do with variation in weather (which is more easily modeled) and much to do with variation in behavioral patterns (e.g., consumers work some days and not others, do laundry on some days and not others, are on vacation on some days and not others, etc.). The result is that for any particular day, usage can be significantly higher or lower than a baseline value estimated using average usage over prior days, no matter how many days are included in that average. Put another way, no average value, no matter how it's derived or how sophisticated the algorithm used to produce it, will accurately reflect what usage would have been on an event day if a consumer had not responded to the PTR incentive.[11]

Some have argued that as long as a baseline is unbiased, overall program costs will be correct for the program even if they aren't correct for any particular participant. This point ignores the potential concern that some participants who work hard to reduce loads may not get paid anything under a PTR program due to baseline inaccuracies, which could lead to consumer complaints. It also ignores the fact that many consumers who do nothing will receive windfall payments and, thus, may be less likely to try and reduce their usage in the future (assuming they'll get paid anyway). Ignoring those concerns, prior analysis by Nexant[12] for other utilities illustrates that aggregate payments for a PTR program that uses an unbiased baseline method can be roughly correct as long as average reductions across all customers are large enough that all overpayments are fully offset by all underpayments. This occurs more often under opt-in PTR programs that attract more engaged participants and, in particular, under programs that combine PTR with enabling technology in order to generate larger average demand reductions. Default programs, on the other hand, are more likely to produce very small average load reductions (below 5%) in the absence of enabling technology and personal event notification for most customers,[13] which leads to overpayments that can far exceed under payments.[14]

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[10] Baselines can be more accurate for some commercial and industrial consumers than for residential consumers if their usage varies little across days, which can be the case for large industrial plants, for instance. Nevertheless, even for large customers, baseline inaccuracies (or bias) can lead to large payment errors. In an evaluation of baseline accuracy for the Ontario Power Authority (recently merged with the Ontario Independent System Operator), Freeman, Sullivan & Co. (now Nexant) determined that the OPA overpaid a single large industrial customer by many millions of dollars due to baseline error. See Josh Bode, Josh Schellenberg and Paul Mangasarian. *2007-2008 Impact Evaluation for Ontario Power Authority's DR-1 and DR-3 Programs*. November 9, 2009.

[11] Nexant has conducted detailed studies of baseline accuracy for four different utilities, PG&E, SDG&E, ComEd and OG&E, comparing bias and precision of several hundred different baseline algorithms. See for example, the OG&E report cited previously and see also Stephen George, Josh Bode and Dries Berghman. *2012 San Diego Gas & Electric Peak Time Rebate Baseline Evaluation.* April 2013. Many methods displayed systematic bias (typically upward bias, which results in overpayments) although some are largely unbiased, meaning that the average error across all customers and all event days is close to zero. However, at the individual customer level, no baseline method produces accurate estimates for specific days or even when averaged across all days.

[12] See, in particular, the reports for OG&E and SDG&E cited earlier.

[13] The widely publicized BG&E PTR program is unusual because so many participants had direct load control devices prior to the creation of the program and because BG&E notifies almost all customers on a default basis using telephone records that were previously available for the majority of customers. While there has yet to be an objective, independent evaluation

In light of the above issues, Nexant does not recommend that CECONY consider implementing default PTR. While opt-in PTR with an unbiased baseline method can better align average settlement payments with actual load reductions, we have focused our analysis on TVP tariffs where measurement error is not an issue and where consumers can make informed usage decisions in response to cost-reflective prices. If, in the future, enabling technology becomes ubiquitous as some stakeholders envision will occur through the REV process and market forces, default PTR may produce large enough average benefits that over and under payments would largely offset each other (assuming an unbiased baseline method is used) so that aggregate program payments would be better aligned with the load reductions achieved. However, even in this situation, it would be true that almost no PTR participants would be paid correctly for the savings provided.

2.4 Report Organization

The remainder of this report is organized as follows. Section 3 describes in detail the cost-effectiveness framework and all data and assumptions that are used in the analysis. Section 4 summarizes the primary results of the analysis, reporting the present value of benefits, costs and net benefits, and the benefit-cost ratio, for each of the five pricing scenarios. Section 5 contains a brief summary of key findings.

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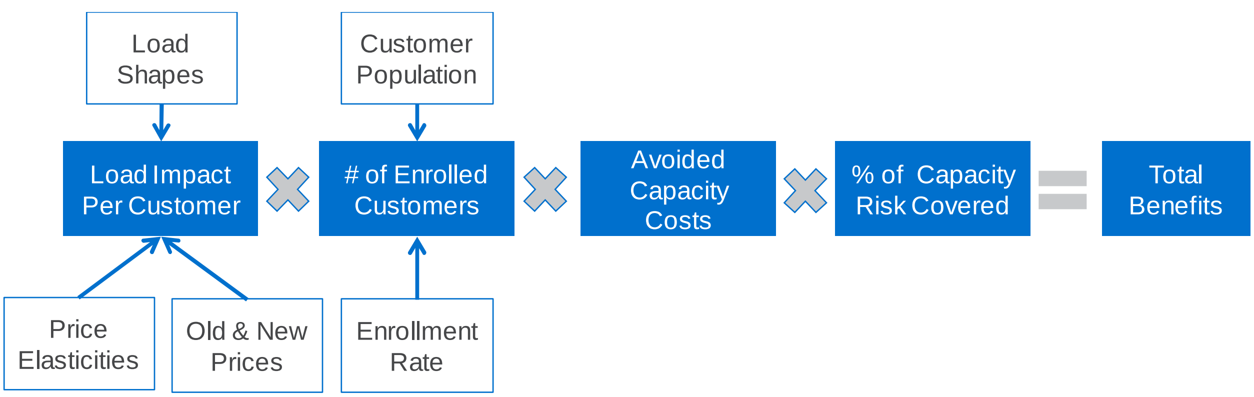
of the BG&E program to estimate demand reductions using something other than the baseline methods used for settlement, it's at least conceivable based on the above that impacts are reasonably large compared with other default programs and, therefore, aggregate payments may be more in line with actual load reductions. Two other utilities that have implemented default programs, SCE and SDG&E, were not able to use pre-existing technology to automate demand reductions for their defaulted customers nor were they willing to incur the cost of or risk the backlash from making personal telephone notifications on a default basis. As such, average impacts for default customers were so small as to be unmeasurable in statistical terms (e.g., the impact reduction signal was too small to distinguish from the noise of day-to-day variation in load even with very large samples) but payments for random fluctuation in loads were quite large.

[14] For a detailed explanation of differences between baseline error, impact error and payment error, and for why there is an asymmetry in payment error when average impacts are small, see the OG&E and SDG&E reports cited previously.

3 Methodology

The basic framework for determining the net benefits of TVP is the standard total resource cost test, which compares the present value of benefits and costs associated with each of the five pricing scenarios summarized in Section 2. The benefits of TVP pricing are primarily a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g., prices by rate period) being examined. These factors drive the change in usage by rate period which, in turn, drives the benefits that can be achieved in the form of avoided generation and distribution capacity investments or reductions in fuel costs or market clearing prices. Figure 3-1 summarizes the main benefit drivers. The one variable in the figure not already mentioned, the % of Capacity Risk Covered, is explained more fully below. In brief, this factor recognizes that TVP impacts do not necessarily produce demand reductions during all hours when generation or distribution capacity relief may be needed. The risk factor is meant to put demand response impacts on a more comparable, apples-to-apples basis with the capacity investments they are intended to avoid.

Figure 3-1: Main Drivers of TVP Benefits



Not included in the above figure, nor in the benefit analysis, are reductions in energy costs that can occur if TVP participants shift usage from higher to lower cost periods or if demand reductions reduce market clearing prices. These benefits tend to be much smaller in aggregate compared with the avoided capacity costs and, therefore, were not included in the analysis. As mentioned in Section 2, excluding these benefits means that the net benefits reported here are understated. The costs associated with implementing TVP tariffs (assuming AMI is already in place) include startup costs, customer acquisition costs and ongoing program administration costs, among others.

The remainder of this section provides greater detail concerning the cost-effectiveness framework and documents all of the data and assumptions underlying the estimation of net benefits for each pricing scenario. Section 3.1 provides a high-level overview of the cost-effectiveness model that underlies the analysis. As indicated there, this model was first developed to determine the cost-effectiveness of CECONY's demand response (DR) programs. These DR evaluations have been shared previously with the NYPSC as have the conceptual framework and detailed documentation of the model. Section 3.2 summarizes the avoided capacity costs that are used in this analysis and explains the "% of Capacity Risk Covered" multiplier shown in Figure 3-1. Section 3.3 describes the rate design used in the analysis while Section 3.4 documents the price elasticities that are used to estimate demand response for customers who enroll on the TVP tariffs. Section 3.5 documents the enrollment assumptions associated with each pricing scenario and Section 3.6 provides an explanation for all of the cost assumptions underlying the analysis. Finally, Section 3.7 briefly documents the remaining input variables required for the analysis.

3.1 Cost-Effectiveness Framework

In 2013, Freeman, Sullivan & Company (FSC)[15] developed a comprehensive framework for estimating the costs and benefits associated with CECONY's demand response programs.[16] This framework explicitly took into account the unique characteristics of CECONY's utility system and the way in which it deploys DR at the local network level. The main output of this work was a cost-effectiveness tool that can be used to understand the value of specific DR programs and how that value could be increased. The framework and tool developed during that effort were a key starting point for the analysis presented here.

A central tenet of the cost-effectiveness framework is that the value of demand reductions in CECONY's territory depends on several factors, including: how well reductions coincide with system and local peaks; performance during reduction events; limits on availability of the resource; and limits on maximum event duration. A second important tenet is that the value of DR resources for distribution systems depends on the characteristics of the distribution area in which those resources are available. Both of these tenets are applicable in the context of time-varying pricing, since the primary goal is the same as for other DR programs: reduce electricity usage during periods of peak demand.

In this analysis, we use the CECONY cost-effectiveness tool (with minor modifications) to estimate the net benefits associated with demand reductions that could be attained using time-varying pricing in CECONY territory over the course of 20 years beginning in 2020. We calculate the present value of these net benefits (2015 dollars) for the five scenarios introduced in Section 2 and also conduct sensitivity analysis on the most important inputs to show how the results are affected by varying the initial assumptions. The results (presented in Section 4) are not intended to represent recommendations for what CECONY should do with regard to TVP or what CECONY will do if AMI is deployed. Rather, the analysis is meant to provide a quantitative estimate of the costs and benefits that would occur under a plausible set of TVP deployment scenarios for the specific, hypothetical TOU-CPP rate used discussed in Section 3.3. The following sections detail the key concepts and modeling steps necessary to generate the load impacts that serve as inputs to the cost-effectiveness model.

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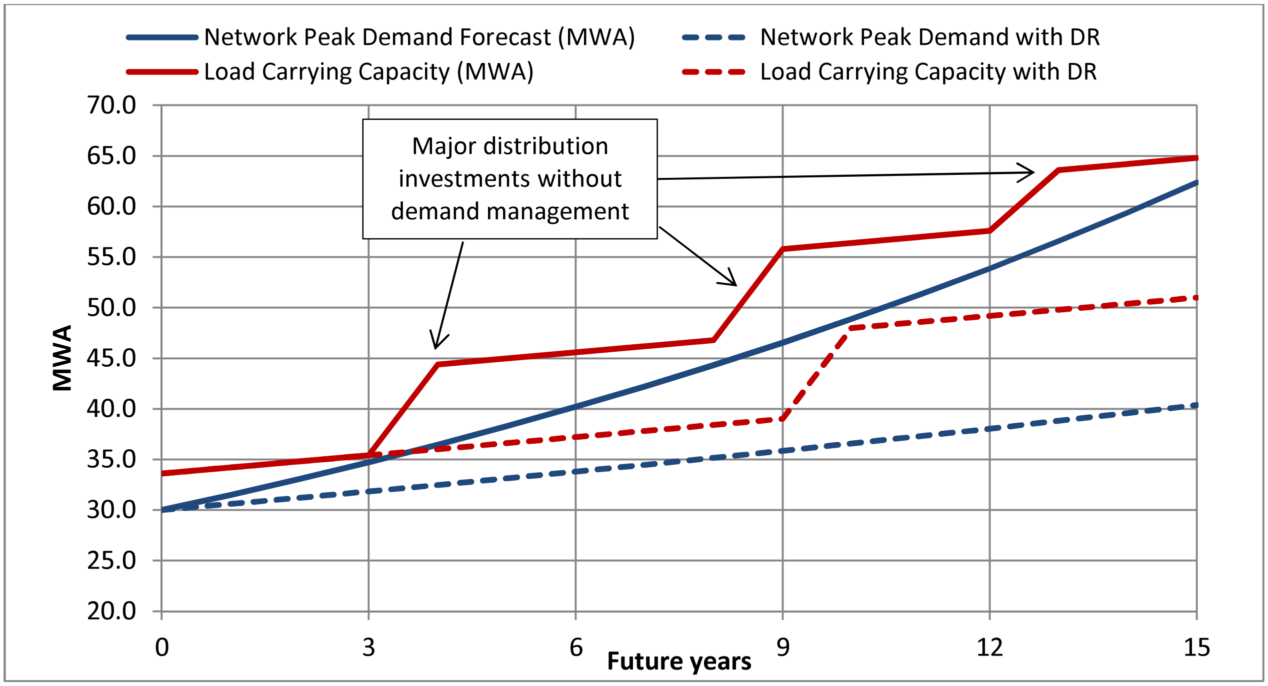
[15] Freeman, Sullivan & Company was acquired by Nexant on January 2, 2014.

[16] See Josh Bode, Stephen George and Aimee Savage. *Cost-effectiveness of CECONY Demand Response Programs* (2013) for a more detailed explanation of the conceptual framework as well as the specific characteristics of CECONY's distribution networks that are relevant for determining the value of demand response.

3.2 Avoided Capacity Costs and Peaking Risk

The benefits of curbing peak demand stem from the fact that peak growth drives a large share of investment in generation, transmission and distribution infrastructure. By reducing peak usage, a utility can delay some of those investments until a later time without adversely affecting the reliability of the grid. Figure 3-2 illustrates this concept for the distribution system. Based on a forecast of peak load growth, the value of avoiding these capacity investments can be quantified for future years at each level of the system (generation, transmission and distribution) so that the benefits of demand reductions in individual hours and months can be estimated. The lower the amount of available capacity in a given year, the higher the value of peak load reductions.

Figure 3-2: Illustrative Effect of Reducing Peak Demand on Distribution Investments



Importantly, a key factor that must be accounted for in the calculation of avoided capacity costs is the coincidence of demand reductions with local and system peaks. Load reductions that occur when system (or an individual distribution network) load is at or near its maximum will be more valuable than reductions that occur when there is plenty of available capacity. As an extreme example, reducing load during summer afternoon hours when peaking risk is high will have substantially higher benefits than shedding load on winter mornings. Conceptually, the benefits of time-varying pricing should be based on the contribution of load reductions in the hours when such reductions are most needed by the system.

Factoring peaking risk into the calculation of benefits requires estimating the likelihood of peaks occurring for each hour throughout the year, which can be done using historical data. Figure 3-3, which shows the probability of a distribution network peaking by hour and by month for one of the eight distribution areas used in the analysis.[17] For the NYISO market and the majority of the local CECONY distribution areas,[18] peaking risk is concentrated in the afternoon during the summer months.

Figure 3-3: Example of Peaking Risk Distribution for CECONY Networks

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

The 2013 cost-effectiveness tool uses this probability distribution to calculate a risk-weighted load reduction for each TVP scenario by multiplying the predicted load reduction in each hour by the probability that the system or an individual distribution network is peaking during that hour. This weighted value captures the overlap between when demand reductions occur and when peaking risk occurs and are used to calculate the benefits associated with avoided capacity costs. The values of avoided capacity costs used in each year of the analysis are shown in Table 3-1. Values at the beginning of the time horizon are based on the 2013 NYISO summer capacity market auction for generation and work done for CECONY by NERA[19] for distribution. These data sources do not contain forecasted values for the entire time horizon considered in this analysis, so costs are assumed to grow at an annual rate of 2.1% after the last estimated value.

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17 CECONY has 83 individual distribution areas in its territory and each of these areas was classified into one of eight groups. A detailed discussion of this process is provided in Bode et. al. (2013).

18 The exception is the Tier 2 – Evening Peaking network group that has (as its name suggests) a later peak.

19NERA. Consolidated Edison Company of New York, Inc. *Marginal Cost of Electric Distribution Service.* Prepared for Consolidated Edison Company of New York. 2012.

Table 3-1: Avoided Generation and Distribution Capacity Cost Values in Analysis Period

Year	Avoided Generation Capacity Cost	Avoided Distribution Capacity Cost – Non-Radial	Avoided Distribution Capacity Cost – Radial
2020	$137.75	$360.81	$216.70
2021	$140.65	$361.56	$213.13
2022	$143.60	$433.72	$280.84
2023	$146.62	$489.34	$331.87
2024	$149.69	$460.94	$298.75
2025	$152.84	$566.53	$399.46
2026	$156.05	$582.49	$410.41
2027	$159.32	$602.87	$425.63
2028	$162.67	$621.31	$438.75
2029	$166.09	$640.24	$452.21
2030	$169.57	$659.77	$466.09
2031	$173.14	$673.62	$475.88
2032	$176.77	$687.77	$485.88
2033	$180.48	$702.21	$496.08
2034	$184.27	$716.96	$506.50
2035	$188.14	$732.01	$517.13
2036	$192.09	$747.38	$527.99
2037	$196.13	$763.08	$539.08
2038	$200.25	$779.10	$550.40
2039	$204.45	$795.47	$561.96

Avoided capacity costs are the only types of benefits considered in this analysis. Additional benefits, such as avoided energy and ancillary service costs, were not included. As such, the net benefits presented here understate what would be realized if those additional benefits were included.

3.3 Rate Design

A variety of TVP structures have been tested in pilot programs and deployed by utilities around the country, including:

Time of use (TOU) – prices vary by time of day every weekday (and perhaps on weekends and holidays);

Critical peak pricing (CPP) – prices vary by time of day only on high demand days (consumers are notified, typically the day before, when a high demand day occurs);

TOU-CPP – combines the two options above, with prices varying on all days but where peak period prices are higher on CPP days than on the typical weekday;

Day-type variable pricing – a set of TOU prices are established and communicated to consumers upon enrollment where prices by rate period vary across three or four different day types (e.g., low price days, moderate price days, high price days, critical price days) and consumers are told prior to each day what price schedule will be in effect on the following day;

Real time pricing – prices change hourly in response to market conditions.

In this analysis, we estimate the impact associated with a hypothetical TOU-CPP rate in which time-varying prices are in effect for all non-holiday summer weekdays and higher prices are in effect for 10 critical peak pricing days on average each year. Nexant sought to design a reasonable rate that followed general principles of cost recovery, economic efficiency, customer equity, and rate simplicity. To meet these objectives, the rates were designed with the following features:

- The **TOU peak period** portion of the tariff is based on marginal generation and energy-related costs;

- The **critical peak period** portion of the tariff is based on incorporating avoided generation and distribution capacity costs into the relatively few hours that drive capacity needs, which occur on high demand days;

- **Revenue neutrality** for the average customer by discounting the base energy prices to offset the higher peak period pricing.

It is important to emphasize that the rates presented in this section are intended to be hypothetical, yet plausible based on Nexant's experience with TVP at other utilities. They are designed to illustrate the potential benefits that can be achieved by passing a price signal through to consumers that reflects the cost of energy and avoided future capacity costs. That said, their design also reflects choices and simplifying assumptions that could be varied and relaxed. As part of the sensitivity analysis presented in Section 4, we illustrate how the benefits would change if different price ratios were used. The benefits would also vary with differences in the rate structure (e.g., demand rates, three period TOU rates, etc.).

3.3.1 Rate Periods

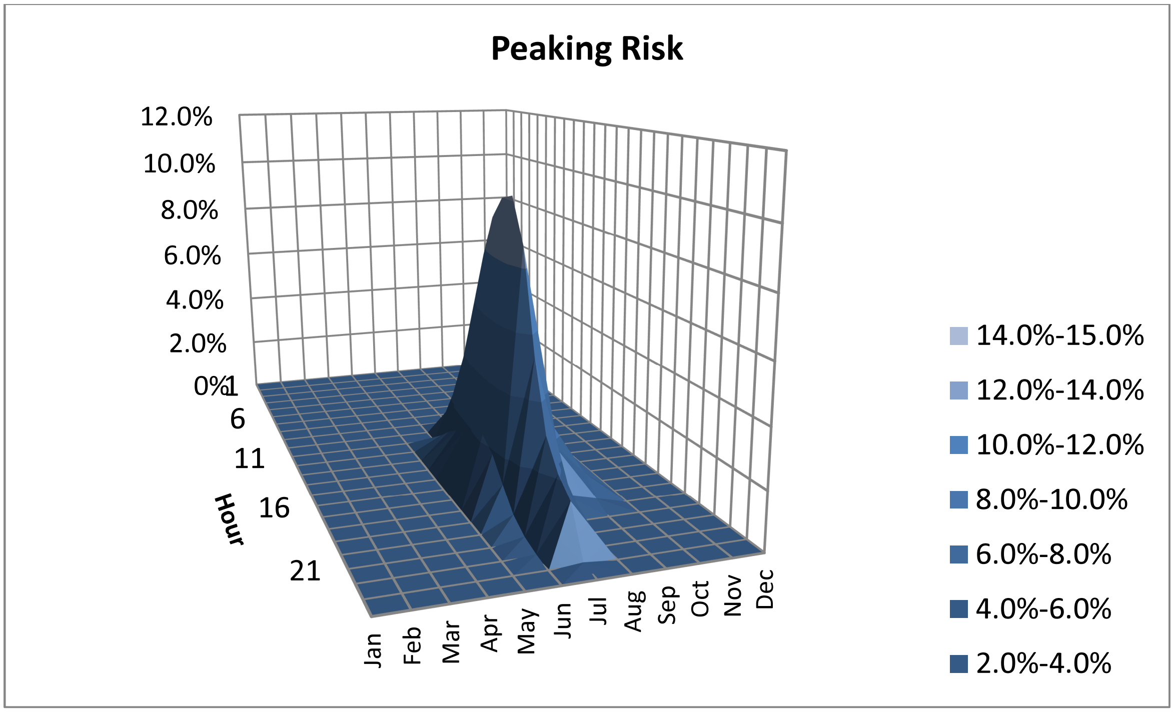
TOU-CPP rates consist of a set of rate periods for two distinct days: normal weekdays (non-event days) and event days. On non-event days, we assume that a TOU pricing structure is in effect consisting of two rate periods: peak and off-peak. On an event day, a critical peak price (CPP) adder is layered on top of the TOU price for all hours that fall inside the CPP window.[20]

[20] The TOU peak period hours do not necessarily have to be the same as the hours in the CPP window. If the CPP peak period differed from the TOU peak period, prices on CPP event days would be based on a three-period rate rather than a two-period rate. It should also be noted that TVP on weekends and holidays might be appropriate for selected networks that are dominated by residential loads.

An effective TOU-CPP rate will have peak periods that are well-aligned with the hours when system or distribution network capacity is likely to peak.

To determine the hours for each TOU-CPP rate period, Nexant assessed the concentration of peaking risk using NYISO system load data from 2011 through 2014 and network group load data from 2010 through 2012. The NYISO system load data was used to determine the TOU peak period and system CPP period. Figure 3-4 shows the generation risk allocation derived from system load. The distribution of peaking risk is concentrated in July in mid-afternoon. A peak period from 11 AM to 7 PM covered 86.1% of the peaking risk.

Figure 3-4: Generation Risk Allocation



The network group load data was used to determine the distribution CPP periods, which could potentially vary across network groups. We identified CPP period windows that achieved at least 80% peaking risk coverage in each network group. In most distribution areas, the distribution of CPP period windows overlaps with the system CPP period window, so the distribution CPP periods were also set to 11 AM to 7 PM for 7 of the 8 network groups to match the system peak period. This simplified the rate structure and allowed both the avoided generation and distribution capacity costs to be incorporated into CPP prices for the majority of networks, while still achieving at least 70% peaking risk coverage. The evening peak network group's CPP period hours were set from 2 to 10 PM. Table 3-2 shows the distribution CPP periods by network group with their associated peaking risk coverage.

Table 3-2: CPP Periods by Distribution Area Type

Network Group	CPP Start	CPP End	Risk Coverage
Tier 2 - Day Peak	11:00 AM	7:00 PM	81.0%
Tier 2 - Evening Peak	2:00 PM	10:00 PM	79.8%
Tier 1 – Day peak - low excess	11:00 AM	7:00 PM	74.3%
Tier 1 – Day peak - high excess	11:00 AM	7:00 PM	71.0%
Tier 1 – Other - low excess	11:00 AM	7:00 PM	79.7%
Tier 1 – Other - high excess	11:00 AM	7:00 PM	78.6%
Radial - low excess	11:00 AM	7:00 PM	82.8%
Radial - high excess	11:00 AM	7:00 PM	89.7%

3.3.2 Prices

After the rate periods were defined based on peaking risk, it was necessary to set the prices that would be in effect during each period. The analysis assumed that both bundled and retail access consumers would have the same rate options. For reasons of economic efficiency, prices should reflect the relative value of reducing the demand for electricity in each period, factoring in both generation and distribution. To develop these prices, we first determined market-based generation and energy-related costs for the TOU peak period of 11 AM to 7 PM during summer weekdays. We used NYISO day-ahead prices from summer, non-holiday weekdays to determine the economically efficient price signal (peak-to-off-peak price ratio) during the TOU peak period. The ratio of average peak to off-peak prices yielded a price ratio of 1.67.

After establishing the TOU peak-to-off-peak price ratio, CPP adders[21] were then determined assuming that 10 CPP events would be called on average during each summer. A key initial input in determining CPP adders is the avoided capacity cost values; we used 2014 avoided capacity cost values of $119.69/kW-year for generation, $243.76/kW-year for network distribution and $115.72/kW-year for radial distribution. Equations 1 and 2 show the calculation of CPP price adders based on the total avoided capacity costs, the number of CPP events, the length of CPP period, and the percent of peaking risk captured. Note that even if distribution network groups have the same avoided capacity costs (as is the case within network and radial groups), the adder will vary because of the different amount of distribution risk captured.

$$\text{CPPadder\_gen} = \frac{\text{Avoided Generation Capacity Cost}}{\text{\# CPP days} \times \text{Length CPP Period}} \times \text{\% System Risk Captured} \quad \textbf{(1)}$$

$$\text{CPPadder\_dist}_i = \frac{\text{Avoided Distribution Capacity Cost}}{\text{\# CPP days} \times \text{Length CPP Period}_i} \times \text{\% Distribution Risk Captured} \quad \textbf{(2)}$$

[21] By "adder" we mean an amount that is added to the TOU price in each period within the CPP window on an event day.

For the 7 network groups for which the TOU and CPP periods align, both generation and distribution adders were included in the CPP prices. For the evening peak network group, only the distribution adder was included.

To determine the new TOU-CPP prices, we first took the TOU price signal and CPP adders as fixed constants and then discounted the off-peak price by a commensurate amount to reach new rates that are revenue neutral.[22] This step necessitated calculating revenue under the current rate structure as well as revenue under the new, TVP structure, which required data on usage by time of day for the average customer within each customer class. We used a representative sample of approximately 350 residential customers to calculate current revenue and solved for new prices that did not increase or decrease revenue, on average. The new TOU peak and off-peak prices are constant across networks, while the CPP adder still varies by network. The new rates were calculated using the following steps:

- Calculate current revenue for the average customer using the variable portion of current prices by network;[23]
- Calculate the average customer's usage in CPP, TOU and off-peak periods by network type; and
- Solve for the TOU off-peak variable price that equates current revenue with revenue under new prices.

Table 3-3 shows the optimal rates by customer type and network group, along with the variable portion of the current flat rate that customers face. Note that the TOU peak-period prices are lower than the original flat rate prices for residential customers and prices during the CPP window are approaching $3.50/kWh (combining the peak price and the CPP adder in the table). This occurs because of high capacity costs driving down optimal off-peak prices. Furthermore, the CPP peak to off-peak price ratio is between 19:1 and 31:1 for residential customers. For comparison purposes, the maximum CPP peak to off-peak price ratio for which pilot studies of load impacts in the region exist is 14:1. In addition, pricing studies indicate that incremental load reductions from additional price increases are small when prices exceed a certain threshold.[24] Because of these reasons, we elected to cap the CPP adder at $1.65 in order for the rate to be considered more reasonable.

[22] The TOU-CPP rate is revenue neutral compared to the standard flat rate if the revenue collected under both tariffs is the same, holding the consumption pattern for the average customer constant for both rates.

[23] Only the variable portion of current prices is used as the customer has no incentive to change consumption when fixed prices change.

[24] See Faruqui and Sergici cited previously.

Table 3-3: Optimal Rates by Customer Type and Network Group

Customer Type	Network Group	Flat Price	TOU Off-Peak Price	TOU Peak Price	CPP Adder
		($/kWh)	($/kWh)	($/kWh)	($/kWh)
Residential	Tier 2 - Day Peak	0.23	0.11	0.18	3.21
	Tier 2 - Evening Peak	0.23	0.11	0.18	2.00
	Tier 1 – Day peak - low excess	0.23	0.11	0.18	3.04
	Tier 1 – Day peak - high excess	0.23	0.11	0.18	2.96
	Tier 1 – Other - low excess	0.23	0.11	0.18	3.17
	Tier 1 – Other - high excess	0.23	0.11	0.18	3.15
	Radial - low excess	0.23	0.11	0.18	1.96
	Radial - high excess	0.23	0.11	0.18	2.03

Table 3-4 shows the optimal capped rates by customer type and network group, along with the variable portion of the current flat rate that customers face. Because the constraint on the CPP adder is binding for all of the network groups, the prices on event days are now identical for every network. With this constraint, the CPP peak to off-peak price ratio is 13.5:1, which is within the range of the price ratios in existing pricing studies that are used to estimate impacts.

Table 3-4: Optimal Capped Rates by Customer Type and Network Group

Customer Type	Network Group	Flat Price	TOU Off Peak Price	TOU Peak Price	CPP Adder
		($/kWh)	($/kWh)	($/kWh)	($/kWh)
Residential	Tier 2 - Day Peak	0.23	0.14	0.24	1.65
	Tier 2 - Evening Peak	0.23	0.14	0.24	1.65
	Tier 1 – Day peak - low excess	0.23	0.14	0.24	1.65
	Tier 1 – Day peak - high excess	0.23	0.14	0.24	1.65
	Tier 1 – Other - low excess	0.23	0.14	0.24	1.65
	Tier 1 – Other - high excess	0.23	0.14	0.24	1.65
	Radial - low excess	0.23	0.14	0.24	1.65
	Radial - high excess	0.23	0.14	0.24	1.65

3.4 Price Responsiveness

After deriving a revenue-neutral TOU-CPP rate, the next step in the methodology is to predict how customers would adjust their energy usage behavior in response to that rate. This is a two-step process involving the estimation of reference loads and the use of a demand model to estimate how usage in each pricing period changes. As mentioned previously, the analysis assumes that both bundled and direct access customers face the same rates. The remainder of this section provides a detailed description of each step.

3.4.1 Reference Loads

A key input to predicting demand reductions in response TVP tariffs is the current load shape for customers who enroll on the rate. Like many utilities, CECONY maintains a load research sample that can be used to estimate loads for different segments of customers in the population. CECONY's load research sample is a stratified random sample consisting of approximately 4,300 customers with the strata for residential customers defined by annual consumption. Residential reference load estimation made use of customers with a residential service class designation (SC1) in the data, which totaled 356 customers. The resulting load estimates are referred to as reference loads throughout this report.

Electricity usage varies throughout the year as seasons/temperatures change and it is important to capture these differences in the reference loads because it has a direct impact on the magnitude of load reductions that can be achieved using TVP at different points in time. In this analysis, we developed a distinct reference load for the average weekday in each summer month (June-September) plus the average event day. Because CPP events are generally called on high demand days when temperatures exceed a particular threshold,[25] we assume that the weather conditions on an event day are independent of the month in which an event occurs. In addition to the interval data for the load research sample, this analysis also makes use of historical weather data.

Each of the four average monthly weekdays is intended to represent exactly what its name suggests – normal weather conditions for a day in each month. Simply using the average loads for customers in the load research sample during these months may not be appropriate since the two years of data (2013-2014) are unlikely to be representative of "normal" conditions. We address this issue by using a regression model to estimate the relationship between usage and weather variables (temperature and dew point) for the period in which we observe load data and then using the estimated parameter estimates to predict hourly usage for weather conditions based on 30-year averages for New York City obtained from the National Oceanic and Atmospheric Administration (NOAA).[26] This process effectively weather-normalizes the load shapes.

For the average CPP event day reference load, the idea is not to capture "normal" conditions, but rather extreme conditions that would result in loads approaching peak distribution and generation capacities. To capture this in the modeling, we identified the 20 days from 2013-2014 with the largest system peaks (based on data from NYISO) and randomly selected 10 of

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[25] CECONY DR events are typically scheduled whenever the next-day load forecast exceeds 96% of distribution network capacity.

[26] NOAA maintains an extensive database of historical weather and climate information that is accessible via http://www.ncdc.noaa.gov/cdo-web/search

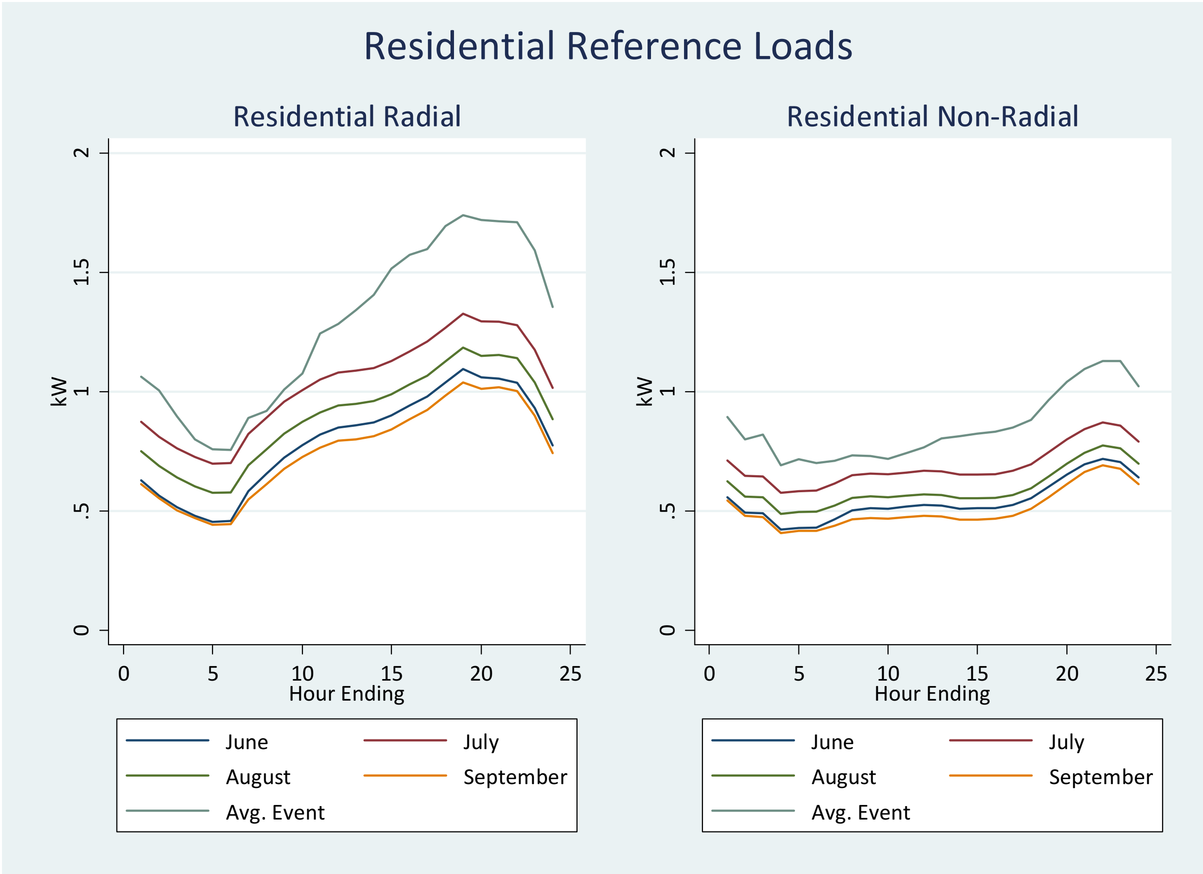
those days[27] to represent typical event days. The reference load for the average event day was then calculated simply as the average of the observed loads on those 10 days.

An important characteristic of customers that has a direct influence on reference loads is whether a customer lives in a single or multi-family dwelling. Single-family dwellings are generally larger, are more likely to contain certain appliances (e.g. central air conditioners, washers and dryers) and are also likely to have larger numbers of a given appliance (e.g. TV, lighting fixtures, etc.). For these reasons, single-family dwellings generally have higher reference loads. This is an important consideration for CECONY because the proportion of single vs. multi-family dwellings varies significantly across its service territory. Dense urban areas such as Manhattan, Brooklyn and Queens have a large number of multi-family dwellings relative to single-family dwellings, while the opposite is true in more suburban locations such as Westchester and Staten Island. Due to sample size constraints in the load research sample, it is not feasible to estimate individual reference loads at the network or even network group level. Instead, we estimate separate reference loads for radial and non-radial network types, which are shown in Figure 3-5. Throughout the analysis, an assumption is made that radial networks predominantly consist of single-family dwellings and non-radial networks primarily consist of multi-family dwellings. This simplifying assumption keeps the analysis tractable while allowing us to account for at least some of the variation in dwelling type.[28]

[27] A random subset of the highest system peak days is used to account for the fact that CECONY will not be able to identify system peak days perfectly and call events only on those days.

[28] This analysis does not address or make any assumptions about net metering for solar or other purposes.

Figure 3-5: Reference Loads for Radial and Non-Radial Networks

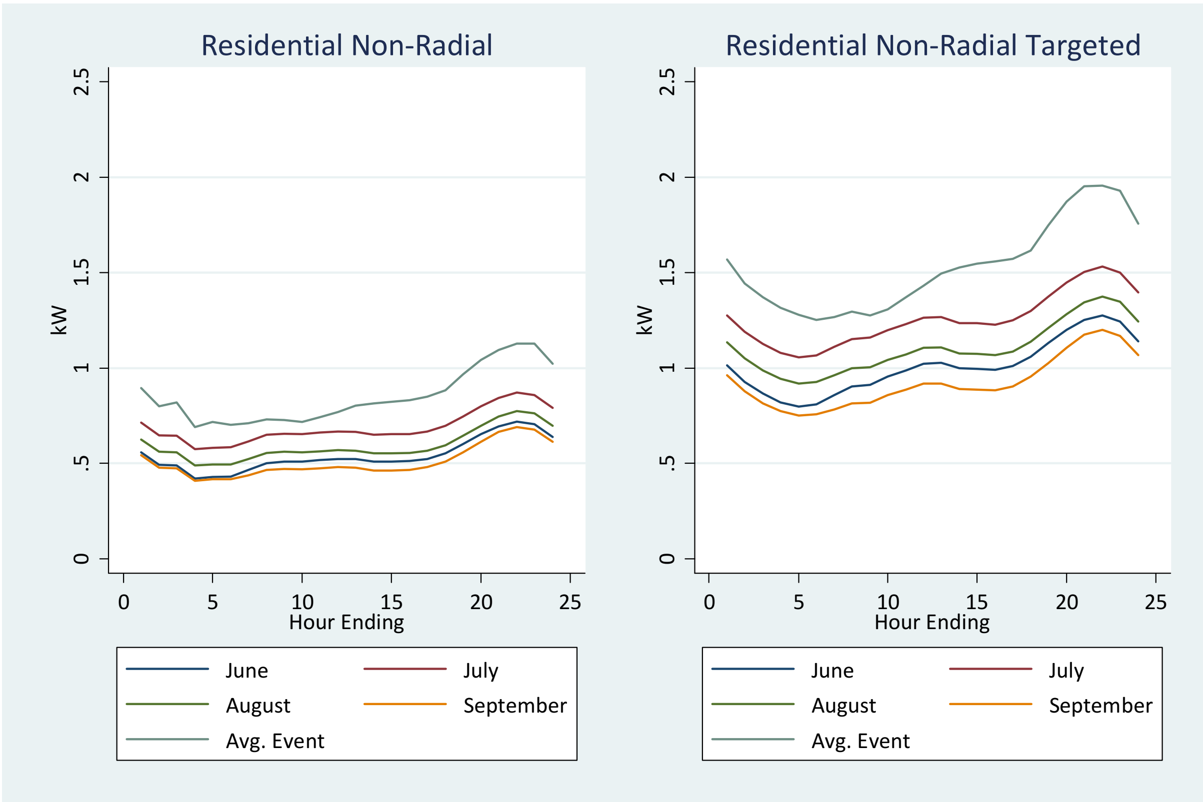


Another important distinction that must be made during reference load estimation is the impact of targeting a particular set of customers for the marketing of time-varying rates. As described in Section 2, the analysis includes two opt-in scenarios (low/high enrollment) in which targeted marketing is used and two other opt-in scenarios that do not include targeted marketing. In the scenarios with targeting, we assume that the targeting is based on usage level – i.e. marketing efforts are focused on customers with higher usage since they have the potential to provide larger load reductions. In order to reflect this in the model, customers recruited onto a TVP rate using targeted marketing should have higher reference loads than customers recruited without any targeting.[29] We achieve this by assuming that targeting efforts would focus on the top two quintiles of the CECONY population defined by annual usage. This definition aligns with the stratification of the load research sample and thus it is straightforward to identify customers in those top two quintiles and use them to develop targeted reference loads using the same

[29] For both the targeted and non-targeted enrollment scenarios, we assume that customers who opt-in to the rate look like the rest of the population in terms of usage. This ignores selection effects that would almost certainly be present in an opt-in environment. Explicitly incorporating selection into the model requires data on observed rate enrollment decisions for individual customers along with accompanying interval data. This information is not available for CECONY since they have very low current enrollment in time-varying rates and also do not have the metering infrastructure for any customers other than those in the load research sample. Selection effects are much less of a concern in a default setting where most customers in the population are assumed to be enrolled on the time-varying rate.

methodology described above. The resulting reference loads in non-radial networks for customers recruited with and without targeting are shown in Figure 3-6.

Figure 3-6: Reference Loads With and Without Targeting in Non-Radial Networks



3.4.2 Demand Model

The second step in predicting how CECONY customers would respond to time-varying rates is to model the specific hourly changes in demand that would be caused by a switch from a flat rate to the TOU-CPP rate developed in Section 3.3. Estimating changes in demand that result from a change in price is a fundamental issue in economics and a large amount of research has gone into developing structural models of demand that capture customer preferences for a good based on its own price and the prices of any complementary/substitutable goods. These models formulate consumer demand as an optimization problem where customers aim to maximize the utility they receive from consuming goods subject to a budget constraint that is defined by prices and income.[30]

In order to be applied to empirical data, demand models must specify a mathematical expression that precisely defines a customer's preferences and governs the tradeoffs that will

30 For a more detailed discussion of consumer demand theory in the context of time-varying pricing, see Appendix 7 of the Impact Evaluation of the California Statewide Pricing Pilot, which can be downloaded from the California Measurement Advisory Council website at http://www.calmac.org/default.asp

be made. In demand models, these preferences are represented by elasticities, which relate changes in consumer demand to changes in explanatory variables such as prices and income. A variety of elasticities exist – e.g., own-price, cross-price and elasticity of substitution – that correspond to how these individual variables affect demand. One of the most widely-used functional forms for time-varying pricing applications is the constant elasticity of substitution (CES) model. The CES model consists of two elasticities that have the following definitions in the context of time-varying pricing:

- Elasticity of Substitution (EoS) – Relates a percentage change in the price ratio between any two rate periods to a percentage change in the electricity consumption ratio between those two periods.
- Daily Elasticity – Relates a percentage change in the average daily price of electricity to a percentage change in the average hourly electricity consumption throughout the day.

Given these two parameters plus data on current consumption (reference loads), current prices (flat rate) and new prices (the revenue neutral TOU-CPP rate), the CES model predicts what the new usage will be.

3.4.3 Data Sources

One of the primary advantages of a structural economic model of demand (provided the specification is adequately capturing actual behavior) is that it allows the researcher to estimate the impacts of price changes without needing to observe the price levels of interest or conduct a pilot to test that particular set of prices. A related benefit is that EoS and daily elasticity estimates can be taken from a study in one territory and used to make predictions about the impact of time-varying rates in another territory. Borrowing estimates in this manner does raise external validity concerns and efforts should be made to find estimates from a population that is as similar as possible to the study area of interest. Fortunately, CES models have been estimated using data from many pricing experiments in the United States, resulting in estimates of EoS and daily elasticities for a variety of different areas. The best of these studies have produced estimates that are similar in magnitude, suggesting that electricity usage behavior is more similar than it is different across the country.

Three pilot programs from the northeastern US were considered as possible sources for elasticity estimates that could be applied to CECONY: Connecticut Light and Power's (CL&P) Plan-It Wise Energy Pilot[31], Baltimore Gas and Electric's (BGE) Smart Energy Pricing Pilot[32] and Pepco's PowerCentsDC Program.[33] Relevant characteristics for each pilot are presented in Table 3-5.

[31] See http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Plan-it%20Wise%20Pilot%20Results.pdf and http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2028178

[32] See http://energy.gov/oe/downloads/bges-smart-energy-pricing-pilot-summer-2008-impact-evaluation

[33] See http://energy.gov/oe/downloads/powercentsdc-program-final-report

Table 3-5: Characteristics of Time-Varying Pricing Pilots in Northeastern Utilities

Characteristic	CL&P Plan-It Wise	BGE Smart Energy Pricing	Pepco PowerCentsDC
Number of Rate Periods	2	2	2
Residential Customers	Yes	Yes	Yes
Standard Residential Flat Rate (all-in)	$0.201/kWh	$0.15/kWh	$0.129-$0.147/kWh
Small Commercial Customers	Yes	No	No
Standard Small Commercial Flat Rate (all-in)	$0.203/kWh	N/A	N/A
TOU period	12-8 pm	2-7 pm	N/A
TOU price ratio (peak/off-peak)	2.0	1.6	N/A
CPP period	2-6 pm	2-7 pm	2-6 pm
CPP price ratio	10.7	14.4	5.6-6.3
Number of CPP events	10	12	15 (12 summer)
Model used to estimate impacts	CES	CES	Customer-level FE
Impacts allowed to vary with weather	Yes	Yes	No
% single-family	N/A	73% treatment, 58% control	N/A
% owning home	77%	96% treatment, 75% control	N/A

As shown in Table 3-5, both the CL&P and BGE studies used the CES model to estimate load impacts caused by TOU and CPP rates. The CL&P study included both small commercial and residential customers and also had flat prices and pricing windows that are more similar to the hypothetical CECONY rate than those in the BGE study. BGE's price ratios, however, are more similar than CL&P's. Though a case could be made for Washington, D.C. being most similar to NYC in terms of the percent of residential customers that live in multi-family dwellings, the estimation methodology and other aspects of the pilot do not lend themselves to using the PowerCentsDC results. For these reasons, the decision was made to use the CES elasticity estimates from the CL&P pilot as the basis for estimating load impacts in CECONY territory.

Like reference loads, price responsiveness is also known to be affected by whether a customer resides in a single- or multi-family dwelling. Because single-family residents have higher loads and more appliances, they are also more able to respond to price signals.[34] As Table 3-5 shows, both the CL&P and BGE pilot programs consisted primarily of participants in single-family dwellings. This creates a potential problem in using CL&P's elasticity estimates since CECONY's territory is known to have a large percentage of multi-family dwellings.[35] To our knowledge, the only pilot that has estimated structural elasticities separately for single-family and multi-family customers is the California Statewide Pricing Pilot (CASPP),[36] which ran from 2003-2005. We estimate a set of multi-family elasticities for CECONY by applying the ratio of multi-family to single-family elasticities from CASPP to the elasticities from the CL&P pilot. Similar to the adjustment of reference loads, we then use these multi-family elasticities for the non-radial network types to estimate load impacts. The final elasticities used in the analysis are presented in Table 3-6.

Table 3-6: Elasticity Parameters Used for Analysis[37]

Customer Segment	Non-Event Days (TOU)		CPP Event Days	
	Elasticity of Substitution	Daily Elasticity	Elasticity of Substitution	Daily Elasticity
CL&P Estimates	-0.047	0	-0.081	-0.026
Single-family (Radial)	-0.033	0	-0.077	-0.026
Multi-family (Non-radial)	-0.023	0	-0.055	-0.038

Although the starting point for CL&P estimates and the final estimates used for CECONY are the same (estimated parameters from substitution and daily equations), the resulting EoS and daily elasticities are not exactly the same because of differences in rate structure, different weather conditions and the multi-family adjustment factor discussed above.

3.4.4 Estimation of Load Impacts Using CES Model

This section presents the calculations used to estimate load impacts for residential CECONY customers in response to the hypothetical TOU-CPP rate described in Section 3.3.[38] As mentioned earlier, there are two parameters needed to estimate these impacts – an elasticity of substitution and a daily price elasticity. The equations presented below are general and will include different quantities, prices and elasticities depending on the network type (radial vs. non-

[34] Empirical evidence from the California Statewide Pricing Pilot supports this claim.

[35] Some of the differences in responsiveness between single- and multi-family dwellings will be captured by using different reference loads for each one, but an explicit elasticity adjustment further reflects our statistically conservative approach for multi-family residences.

[36] See George and Faruqui (2005)

[37] The exact values of the EoS and daily elasticity vary with weather conditions on non-event days. August values are shown in the table.

[38] We present only the final equations used for estimation. For step-by-step derivations of these equations from the underlying CES model, see Appendix 8 of the Load Impact Evaluation for the California Statewide Pricing Pilot.

radial) and enrollment strategy (targeted vs. non-targeted) being considered. All reference loads represent an average residential customer within a particular segment and thus, all predicted impacts are also averages.

The first step of the load estimation is to use the daily elasticity to predict the average daily load that would result under the TOU-CPP rate:

$$\overline{K}' = \overline{K} * \left(\frac{\overline{P}'}{\overline{P}}\right)^{d}$$

Where *d* is the daily price elasticity, K bar is equal to the average kWh/hour during the entire day, P bar is the average price per kWh during the day and primed values denote new levels under the TOU-CPP rate. Once the new average kWh/hour is calculated, the average usage (kWh/hour) in each of the three periods that make up the day can be calculated using the following equations:

$$K_1' = e^{A_{12}} K_2'$$

$$K_2' = \frac{24\overline{K}'}{e^{A_{12}} h_1 + h_2 + e^{-A_{23}} h_3}$$

$$K_3' = e^{-A_{23}} K_2'$$

In these equations, the h_i terms denote the number of hours in each period and the A_{ij} terms are defined as follows:

$$A_{ij} = \ln\left(\frac{K_i}{K_j}\right) + EoS_{ij}\left(\ln\left(\frac{P_i'}{P_j'}\right) - \ln\left(\frac{P_i}{P_j}\right)\right)$$

As in the daily equation, prime values denote new consumption levels that are associated with the TOU-CPP rate. Once the new usage is determined for a given period, the absolute kW impact can be calculated by subtracting the original usage from the new usage. This impact is then applied uniformly to all of the hours in that period to provide a full set of hourly impacts.

The CL&P pilot estimated separate elasticities for TOU and CPP days, which we apply to non-event and event days, respectively. A nuanced benefit of the CL&P pilot is that the analysis was conducted in a way that allowed the elasticities to vary with weather conditions. There is substantial empirical evidence from all three pilots that load impacts (both absolute and relative) increase with temperature. In the case of the CL&P pilot, this relationship was accounted for by interacting the elasticity of substitution term with a variable based on a temperature-humidity index (THI) defined as follows:

$$THI = 0.55 * Drybulb\ Temperature + 0.2 * Dew\ Point\ Temperature + 17.5$$

For estimation, THI was calculated at the hourly level and included in the regression model as the difference in average THI between the peak and off-peak periods of the time-varying rate

(THI_diff). This is the parameter that was multiplied by the values of THI_diff for each set of weather conditions (June-September and average event day) to produce different elasticities for each one.

3.4.5 Summary

In summary, the specific TOU-CPP rate driving the benefits for this analysis is a revenue neutral tariff relative to CECONY's standard residential rate. The peak and off-peak prices on a non-event weekday are based on the variation in energy costs across rate periods and the CPP adder is based on the sum of avoided generation and distribution costs. The CPP adder is capped so that the overall peak-to-off-peak price ratio stays within the bounds of historical experience with such rates. The load shapes and price elasticities used differ between the radial systems comprised of residential households with higher demands and greater saturations of central air conditioning and the network systems that have much lower average loads and much higher concentrations of multi-family households and room air conditioners. With these factors taken into consideration, we believe the analysis does a good job of reflecting the characteristics of the CECONY residential population.

3.5 Enrollment Rates

Customer enrollment on TVP tariffs is influenced by a number of factors, including customer characteristics, enrollment strategy (e.g., opt-in versus default), rate characteristics and the marketing strategies and tactics used to encourage participation. TVP tariffs have been available at many utilities for several decades and in most cases, enrollment has been extremely low. The primary explanation for this is that in most instances, utilities have not marketed these rates actively and/or effectively. Having a rate available that only a handful of customers are aware of due to lack of communication and marketing is not an accurate reflection of customer preferences for TVP rates. There is extensive market research associated with TVP pilots and programs showing that the majority of customers who do enroll on TVP rates are highly satisfied and that dropout rates are extremely low. At the same time, market research also shows that when customers are asked whether they want to sign up for a TVP rate, most will say no. These findings suggest a high level of inertia and strong preferences for remaining on an existing rate, regardless of what rate it is. This is why default pricing is worthy of consideration and why well structured, pro-active marketing campaigns are essential for achieving reasonable enrollment on TVP rates.

Many TVP pilots have focused primarily on meeting enrollment quotas needed for statistical analysis of load impacts and focused little attention on estimating enrollment rates based on marketing strategies that might actually be employed on a broader scale. The SMUD SPO pilot is an exception to this general rule. SMUD offered a variety of rate options (TOU, CPP, TOU-CPP) to randomly selected groups of customers on both an opt-in and default basis and was very meticulous about treating all groups equally in terms of marketing tactics so that the only thing that differed across the treatment cells were the rate characteristics and the tailored messaging for each tariff option. The acceptance rates for CPP and TOU tariffs on an opt-in basis in the SPO were 18.8% and 16.4%, respectively. On a default basis, the opt-out rates (the percent of customers who opt-out after notification of the impending rate change but prior to being placed on the rate) for CPP, TOU and TOU-CPP were 4.1%, 2.4% and 7.1%, respectively. As discussed in Section 3.6.3, SMUD did a significant amount of customer research to determine how best to communicate with and educate customers about the rate options, which explains in part why enrollment and retention rates were so high.

The SMUD pilot is the basis for the assumed enrollment rate of 15% used in the two high opt-in TVP scenarios (targeted and non-targeted). While SMUD's population differs from CECONY's and enrollment rates may differ, we believe that 15% enrollment is achievable if driven by extensive customer research (this effort is factored into the cost analysis) that informs the development of plans for communicating with customers and educating them about the rate. However, in the interest of having estimates that are conservative, we also included a $25 signup incentive in the high opt-in, non-targeted scenario and a $50 sign-up incentive in the high opt-in, targeted scenario. Market studies done at PG&E indicate that a modest sign-up incentive can double enrollment rates for CPP tariffs compared with marketing campaigns that do not pay incentives.[39] There are also well known examples of much higher enrollment rates for TOU tariffs. Salt River Project and Arizona Public Service have roughly 25% and 50% of their customers currently enrolled on TOU rates after several decades of concerted marketing. Over roughly a three year marketing campaign, Oklahoma Gas and Electric (OG&E) has enrolled roughly 15% of their target population onto their SmartHours Rewards program. Given these observed enrollment rates from actual TVP tariffs offered by utilities, we believe that the assumption of a 15% enrollment rate based on extensive customer research and modest sign-up incentives is reasonable.

The two low opt-in scenarios assume a 5% enrollment rate. This is roughly equal to the enrollment rate that PG&E has achieved for its SmartRate program, which is a pure CPP rate that has been offered to selected customers since 2008. PG&E has about 130,000 customers enrolled in SmartRate, or about 3% of its residential population. However, PG&E has not marketed the rate to its entire population but has instead focused its marketing on higher use customers in warmer climate regions. A detailed analysis of PG&E's marketing efforts over time showed that enrollment rates can vary significantly across customer segments and based on different marketing strategies and offers. Depending on the target population, the use of sign-up incentives, the timing of the campaign, number of direct mail contacts, and other factors, enrollment rates varied from a low of 1.6% to a high of 24%. On average, the enrollment rate was 4.2% across roughly a dozen market and segment tests over the course of two years. In the first year of the program, PG&E obtained an enrollment rate of 8% using a direct mail campaign with no sign-up incentives.[40] Based on this evidence, we believe it is reasonable to use an enrollment rate of 5% for the low opt-in scenarios, one of which (the targeted scenario) assumes use of a sign-up incentive of $25.

The enrollment/opt-out rate for the default scenario is based on the SMUD SPO pilot which, as discussed above, showed opt-out rates for three different rate options ranging from less than 3% to roughly 7%. The analysis presented here assumes an opt-out rate of 10%, roughly double the average of the three SPO treatment groups. .

[39] See Pacific Gas and Electric Company Rate Design Window 2012. Appendix A, Volume 1. Report in Compliance with D.11-11-008 OP3. Report on SmartRate™ and TOU Tariffs. February 29, 2012.

[40] Ibid.

3.6 Costs

Each of the five scenarios outlined above has different cost assumptions associated with implementation that must be factored into the cost effectiveness analysis. Costs are assumed to vary over time according to three implementation stages. Stage 1 is the prelaunch period during which program design would occur, IT systems to support billing and enrollment would be constructed, and marketing materials and strategies would be developed. Stage 2 is the ramp up period during which primary program recruitment would occur and stage 3 is the steady state period. In each scenario, stage 1 is assumed to last one year, stage 2 is assumed to last two years following the prelaunch period, and stage 3 covers the remaining 17 years of the assumed 20 year forecast horizon.

The following cost categories were factored into the analysis:

- **Program design and administration**: In the prelaunch stage, this category is assumed to cover all startup costs other than IT system development and development of marketing materials, which are accounted for in other cost categories. During this stage, costs are assumed to include a program manager, other staff and consultants involved in developing implementation details. During the ramp up and steady state periods, this category is comprised of internal program staff dealing with day-to-day operations. Staffing requirements are assumed to be a function of the overall magnitude of participants and are largest for the default scenario.
- **IT systems**: During the prelaunch period, this cost category covers development of new IT systems and business processes required to enroll customers on the tariff and to generate bills based on interval data for the TOU-CPP rate. During the ramp up and steady state periods, this category covers ongoing licensing and IT operations and maintenance costs.
- **General marketing**: This cost category during the prelaunch stage covers development of all marketing materials. During the ramp up and steady state periods, this category covers general advertising and awareness for the opt-in scenarios and general awareness and education for the default scenario. It does not include customer-specific acquisition costs, which are covered in the following category.
- **Customer specific acquisition costs**: These costs are assumed to occur only during the ramp up period when the primary marketing activities occur or, for the default scenario, when customers are processed into the program on an opt-out basis. This category includes direct mail costs for the opt-in scenarios, marketing incentives (under some scenarios but not others), processing costs involved in transitioning customers onto a new rate, and welcome kits sent to each new enrollee. Acquisition costs for replacement customers or customers who move within the service territory are covered in the following cost category.
- **Other one-time costs:** These costs are assumed to apply only to new enrollees that move into CECONY’s service territory. This category includes the cost of a welcome kit for all new enrollees and, under some scenarios, a sign up incentive. Prior program participants who relocate within the service territory are assumed to sign up again at no additional cost (e.g., CECONY will track their prior rate and offer it to them as a default option when they move elsewhere within the service territory).
- **Recurring engagement costs:** This category includes notification costs for CPP events each year as well as incremental call center costs dealing with event-day questions, bill inquiries around TOU rates, etc.

- **Program evaluation**: This final cost category assumes that CECONY will estimate load impacts from the program each year using an objective, outside contractor to conduct the evaluation.

The cost estimates included in this analysis are meant to be indicative of what might be needed to support each pricing scenario. Wherever possible, they are based on evidence from pricing pilots or programs that have been implemented by other utilities or on CECONY costs for marketing campaigns for other programs. In some cases (such as IT system costs) the values might be best considered ballpark assumptions with a high degree of uncertainty since IT development and implementation costs can vary greatly across utilities and applications. Evidence from other utilities may also be more applicable for some cost categories than for others. For selected scenarios, we present the results of sensitivity analyses in which cost estimates (and other variables) are varied systematically in order to determine how sensitive the net benefit estimates are to different input values.

3.6.1 Program Design and Administration

This category covers the cost of in-house staff assigned to manage the TOU-CPP program during the analysis period, including program development, the intensive ramp up period and the long-term steady state period. During the design phase, we assume that a project manager and assistant will be needed full time for a year to get ready for the program launch. The cost of an FTE project manager, fully loaded, is assumed to equal $180,000 per year, which is comprised of a base salary of $100,000 per year and 80% overhead rates.[41] The cost of an assistant is assumed to be $135,000 per year, with a base salary of $75,000 plus 80% overheads. These labor requirements are assumed to be largely invariant across the opt-in scenarios since, for example, it doesn't take more effort to plan for a high opt-in versus low opt-in enrollment scenario. For the much larger default program, we assume an additional FTE assistant would be employed during the prelaunch phase.

We also assume that CECONY would require outside consulting services for design and implementation planning for all scenarios, at a base cost of $200,000. For the targeting scenarios, we assume that an additional cost of $200,000 would be needed to develop targeting models and strategies. For cost purposes, we also assume that a more sophisticated targeting strategy would be developed and used rather than the simple one used to model load impacts (which simply took the top two usage quintiles). For the default scenario, we assume that an additional $500,000 would be spent developing new business processes and operational plans for the much larger default process.

During the ramp up period, we assume that administration requirements are tied to the number of expected enrollments in a stepwise fashion. As seen later in Section 4.2, three of the five scenarios have enrollment levels between roughly 60,000 and 175,000, one has enrollment of roughly 430,000 and the default scenario has enrollment around 2.6 million. For the three lowest enrollment scenarios, we assume that, in addition to the project manager and assistant needed during the prelaunch period, one more FTE assistant is employed each year at an annual cost of $135,000. For the no targeting, high-opt-in scenario, we add one more FTE

41 Based on input from CECONY.

assistant to the Scenario 1 level of support and for the default scenario, we add 3 more FTEs to the Scenario 1 level of support. In summary, costs during the ramp up period, for both the targeted and untargeted, low-opt in scenarios, and for the targeted high opt-in scenario, are based on one project manager and two assistant FTEs. Costs for the no targeting, high opt-in scenario are based on one project manager and 3 FTE assistants. In the default scenario, project administration requires a project manager and 6 FTE assistants.

During the steady state period, under all four opt-in scenarios, we assume the program can be operated by a project manager and an assistant. For the default scenario, the steady state costs are based on a project manager and two assistants. Table 3-7 summarizes the program design and administration costs for each scenario and program stage.

Table 3-7: Annual Costs for Program Design and Administration

Scenario	Period	Cost Estimate ($000/yr)	Details
1. Low opt-in	Prelaunch	$515	1 FTE project manager @ $180k; 1 FTE assistant @ $135k; Outside consulting services for design and implementation planning @ $200k
	Ramp up	$450	1 FTE project manager @ $180k; 2 FTE assistants @ $135k each;
	Steady state	$315	1 FTE project manager @ $180k; 1 FTE assistant @ $135k;
2. Low opt-in, targeting	Prelaunch	$715	Same as scenario 1 + $200k for outside assistance in development of the targeting strategy
	Ramp up	$450	Same as scenario 1
	Steady state	$315	Same as scenario 1
3. High opt-in	Prelaunch	$515	Same as scenario 1
	Ramp up	$585	Same as scenario 1 + 1 FTE assistant @ $135k
	Steady state	$315	Same as scenario 1
4. High opt-in, targeting	Prelaunch	$715	Same as scenario 2
	Ramp up	$450	Same as scenario 1
	Steady state	$315	Same as scenario 1
5. Default	Prelaunch	$1,150	Same as scenario 1 + 1 FTE assistant @$135k + additional outside consulting services involving new business process development @$500k
	Ramp up	$855	Same as scenario 1 + 3 FTE assistants @ $135k each
	Steady state	$450	Same as scenario 1 + 1 FTE assistant @ $135k

3.6.2 IT System Costs

Calculating bills for a TOU-CPP rate will require changes to CECONY's billing system software. There was not sufficient time for CECONY to develop bottoms-up estimates of what these costs might be for their billing system. As such, the estimates used here are based on the relatively sparse data available from other utilities. CECONY considered how best to approach this process without full replacement of its existing billing system and concluded that usage amounts by rate period could be developed in the new meter data management software (MDM) that will be purchased to support use of AMI data for multiple purposes. The cost for the MDM system is already included elsewhere in the AMI business case and, as such, is not counted as an additional cost for the analysis of TVP. Usage amounts in each rate period from the MDM would be fed into the existing billing system, although even this approach would require significant software and business process changes to the current billing system that has been in place at CECONY for many decades.

In a prior study by Nexant for Oklahoma Gas & Electric (OG&E) involving analysis of a peak time rebate (PTR) program for roughly 500,000 customers, OG&E's IT group provided estimates ranging from a low of $8 million to a high of $17 million for software development to support billing for PTR (which would have similar billing requirements as a TOU-CPP rate).[42] In a filing in support of a PTR program by Commonwealth Edison Company,[43] ComEd estimated that one-time IT capital and O&M costs would total $15 million over two years. The predicted size of the ComEd program was assumed to be roughly 500,000 customers. Given these estimates, we assume that software development to support the four opt-in scenarios, with enrollment ranging from roughly 60,000 to 430,000, would be in the same range as the above estimates, or around $12.5 million. We assume that the much larger default scenario, involving roughly 2.6 million customers, would require software and business process development costs of twice that amount, or $25 million.

OG&E's estimates for annual O&M costs for IT systems were 10% of the development costs, for an average $1.25 million per year. We adopt this same assumption here, which produces an estimate of $1.25 million per year for the four opt-in scenarios, and $2.5 million per year for the default scenario. We assume this cost is the same during both the ramp up and steady state periods.

3.6.3 General Marketing

The general marketing cost category covers all marketing costs other than direct mail and other forms of customer-specific communication. During the prelaunch phase, this category covers development of all marketing materials, including customer-specific outreach materials such as direct mail letters and brochures. During the ramp up and steady state periods, this category covers general advertising and awareness for the opt-in scenarios and general awareness and education for the default scenario.

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42 See George (November 2, 2012)

43 Testimony of Jim Eber, Manager of Demand Response and Dynamic Pricing, ComEd, Exhibit 3.01. Petition for Statutory Approval of a Smart Grid Advanced Metering Infrastructure Plan pursuant to Section 16,108.6 of the Public Utility Act.

The approach to marketing would likely vary across scenarios. Marketing strategy is a key driver of program enrollment, as evidenced by the variation in enrollment rates for TVP programs discussed in Section 3.5. Marketing options and costs will vary depending on whether a rate is implemented on an opt-in or default basis or, for opt-in scenarios, whether or not the marketing is targeted to a subset of customers or directed to all customers. Under a targeting scenario, general media campaigns cannot be used since those who are not being targeted would be exposed to the advertising. Mass media campaigns can be used for non-targeted scenarios but may be expensive and relatively ineffective. For the default scenario, mass media awareness and educational campaigns would be needed during the ramp up period.

General marketing costs during the prelaunch period are assumed to cover development of all marketing materials and strategies. This would likely include focus groups to develop sound messaging plus channel strategies and educational materials for each scenario. During the buildup to its very successful SPO pilot, SMUD obtained input from roughly 2,500 customers through 20 focus groups and four surveys to develop successful names for each rate plan, preferred messaging and channels of communication for various customer segments and educational materials in the form of welcome kits and other ongoing communication.[44] This extensive research was one of the key reasons why SMUD was able to achieve enrollment rates between 15% and 20% for their opt-in pricing plans and had an opt-out rate prior to enrollment of roughly 5% for their default plans. At a cost of roughly $15,000 per focus group and $50,000 per survey, this level of effort would cost approximately $500,000. We assume that this is the level of effort that CECONY would employ for the two relatively more successful, high opt-in scenarios and that the less successful opt-in scenarios would involve a level of effort for customer research of half that amount. For the default scenario, we assume that even more focus groups and surveys would be employed to address special interest concerns and to support development of a wider array of educational materials to reach all customer segments. For this scenario, we assume that an additional expenditure of $200,000 on customer research would be required, for a total of $700,000.

SMUD's development of marketing materials for the SPO pilot involved outside service costs of more than $600,000 for seven different pricing plans. Development of materials for a single pricing plan is assumed to require expenditures of $200,000 for each of the four opt-in scenarios analyzed here. Given the greater attention to various customer segments under the default scenario, we assume these costs will total $400,000.

General marketing cost assumptions during the ramp up period differ significantly across scenarios. As indicated above, mass media advertising cannot be used for targeting specific customer groups that are located throughout the CECONY service territory. On the other hand, mass media advertising would likely be a critical element of any large scale default scenario. The cost of media advertising varies significantly across different communication channels (e.g., radio, television, etc.) and media markets and we have not attempted to do a bottoms-up estimate of media costs for any of the scenarios. We assume that media costs for the two

[44] SmartPricing Options Interim Evaluation. October 23, 2013.

targeted scenarios equal 0, the costs for the two opt-in scenarios equal $2 million per year during the ramp up period, and equal $5 million per year for the default scenario. During the steady state period, we assume this type of advertising would no longer be used for any of the opt-in scenarios and all new and replacement enrollment would occur through the business processes tied to customer requests for service. For the default scenario, we assume a low level media campaign would be conducted each year during the steady state period to remind consumers that the summer is approaching and that avoiding usage during peak periods will help control costs. General awareness campaign costs for the default scenario are assumed to equal $500,000 per year for the steady state period. Table 3-8 summarizes the cost assumptions for general marketing for each scenario and implementation phase.

Table 3-8: General Marketing Costs

Scenario	Period	Cost Estimate ($000/yr)	Details
1. Low opt-in	Prelaunch	$450	$250k for customer research; $200k for development of marketing materials
	Ramp up	$2,000	$2 million per year for media advertising
	Steady state	0	0
2. Low opt-in, targeting	Prelaunch	$450	Same as scenario 1
	Ramp up	0	0
	Steady state	0	0
3. High opt-in	Prelaunch	$700	$500k for customer research; $200k for development of marketing materials
	Ramp up	$2,000	Same as scenario 1
	Steady state	0	0
4. High opt-in, targeting	Prelaunch	$700	Same as scenario 3
	Ramp up	0	0
	Steady state	0	0
5. Default	Prelaunch	$1,100	$700,000 for customer research $400,000 for development of marketing materials
	Ramp up	$5,000	$5 million per year for media advertising
	Steady state	$500	$500k per year for general awareness

3.6.4 Customer Specific Acquisition Costs

This category covers costs associated with customer acquisition for each of the pricing scenarios. There are four subcategories of costs included here: customer-specific communication costs for materials such as direct mail; an enrollment incentive (selected scenarios only); welcome kits that explain how the rate works and educates consumers about the kinds of behavioral changes that could lead to lower bills; and the cost of processing a tariff change. These costs are assumed to apply only during the ramp up period. There are no prelaunch costs in this category (materials development was covered under the general marketing category) and acquisition costs associated with new and replacement customers during the steady state period are handled through the "one-time cost" category primarily because this was the best way to incorporate these costs into the cost-effectiveness model as it currently exists.

Customer-specific communication costs are based on a direct mail marketing campaign for the opt-in scenarios and the assumption that each customer would receive 3 mailings over the course of the two year ramp up period. The cost per mailing, $1.00, is based on prior CECONY experience with large direct mail campaigns. The average cost per acquired customer for direct mail marketing is a function of the enrollment rate for each scenario. In other words, if each customer targeted for enrollment receives 3 direct mail pieces on average, and the enrollment rate is 5%, the average cost per enrolled customer equals $60 ($3.00/0.05). On the other hand, if the enrollment rate is 15%, the average cost per enrolled customer is $20 ($3.00/0.15). In light of rapid advancements in lower cost direct communication options such as email marketing, these estimates may overstate what an actual direct marketing campaign might cost. For example, CECONY estimates that the cost per email for outreach to customers for whom the Company has email addresses is just $0.004 per touch.

Given the number of enrolled customers in each of the opt-in scenarios shown above in Section 3.5, the direct mail marketing costs range from a low of roughly $3.6 million in total over two years for targeted, opt-in scenarios to a high of roughly $8.6 million over two years for the opt-in scenarios without targeting. These values are shown in Table 3-9 at the end of this section. For the default scenario, we assume that each customer will be notified twice through direct mail regarding the impending change to the default rate. The total population of residential customers who would be notified about the default rate over two years would roughly equal 2.9 million, so the cost for default notification would equal roughly $5.7 million.

The next subcategory of costs is for marketing incentives. Research by Nexant in conjunction with PG&E's SmartRate tariff[45] indicates that relatively modest sign up incentives in the range of $25 to $50 can significantly improve enrollment rates.[46] Although SMUD obtained high enrollment rates for all pricing plans without the use of incentives, and Arizona Public Service and Salt River Project have obtained enrollment rates in the 25% to 50% range over a long period of time without using incentives, we nevertheless assumed that a signup incentive would be needed to boost enrollment rates to the levels assumed in the two high opt-in scenarios. We have included an incentive of $25/enrolled customer for the non-targeted, high opt-in scenario. For the targeted, high opt-in scenario, we assume a $50 incentive per enrolled customer would be needed in order to attract these higher use customers who have greater saturations of

[45] SmartRate is a critical peak pricing tariff with no TOU component.

[46] See PG&E (February 29, 2012)

central air conditioning and for whom research indicates are more difficult to attract onto TOU rates than lower use customers.[47]

The third cost element tied to initial recruitment onto each rate is a welcome kit that explains the details of the rate and provides education and tips concerning how changes in the timing of electricity use can reduce bills. In SMUD's SPO pilot, the cost for welcome kits equaled $2.50 per enrolled customer. We use this value here.

The final customer acquisition cost is associated with processing the changes in CECONY's customer information system (CIS) and billing systems as customers begin transitioning to the new rate. This cost is difficult to estimate as it is tied to the business processes that each utility uses to make such changes, the percent of changes that are made through the call center (CSR) versus business reply cards (BRC) and other factors. Costs could also vary depending on whether they are handled one at a time or in bulk through overnight batch processing. Once again, we turn to the SMUD pilot for data on this activity. SMUD estimated that, for the opt-in pricing plans, each rate change would cost $29 in terms of CSR labor costs and administrative costs for BRC processing. Assuming that labor rates are higher at CECONY than at SMUD, we used an estimate of $32/enrolled customer. This estimate may be quite high, however, if many changes can be made through a self-service web portal.

For the default scenario, we assume that the cost of opting-out of the default rate would require the same amount of effort as it would take to opt-in to a rate plan under the other scenarios. This cost would apply to the assumed opt-out rate of 10% of the population, or roughly 287,000 residential customers. For the 90% of customers who are assumed to stay on the rate, we assume that these changes would be done using batch processing at a cost of $0.50/change, for a total cost of roughly $1.4 million.

Table 3-9: Recruitment Costs

Scenario	Period	Cost Estimate ($million/year)	Details
Low opt-in	Ramp up	$6.8	DM costs = ($60/enrolled customer)x(143,424) = $8.6m Welcome kits = ($2.50)x(143,424) = $0.359m Processing rate changes = ($32)x(143,424) = $4.6m
Low opt-in, targeting	Ramp up	$2.8	DM costs = ($60/enrolled customer)x(59,717) = $3.6m Welcome kits = ($2.50)x(59,717) = $0.149m Processing rate changes = ($32)x(59,717) = $1.9m
High opt-in	Ramp up	$17.1	DM costs = ($20/enrolled customer)x(430,270) = $8.6m Sign up incentives = ($25/enrolled customer)x(430,270) = $10.8m Welcome kits = ($2.50)x (430,270)= $1.08m Processing rate changes = ($32)x(430,270) = $13.8m
High opt-in, targeting	Ramp up	$9.2	DM costs = ($20/enrolled customer)x(176,148) = $3.5m Sing up incentives = ($50/enrolled customers)x (176,148) = $8.8m

[47] See George, Potter and Jimenez. (2014)

			$Welcome kits = ($2.50)x(176,148) = $0.44m Processing rate changes = ($32)x(176,148) = $5.6m
Default	Ramp up	$11.8	DM costs = ($2.00 per customer)x(2,868,469) = $5.7m Welcome kits = ($2.50)x(2,868,469) = $7.2m Processing rate changes = ($32)x(287,000) + ($0.5)x(2.87m) = $10.6m

3.6.5 Other One Time Costs

These costs are assumed to apply only to new enrollees that move into CECONY's service territory. CECONY has a high turnover rate among multi-family households, roughly equal to 25%. However, most customers who move from away from their current location relocate elsewhere within CECONY's service territory. The exact percentage of movers who relocate elsewhere within the service territory is unknown. In SMUD's service territory, the total turnover rate is roughly 20%. SMUD also has high customer churn due to having a high percentage of customers in multi-family units and also because of being a state capital where turnover can be tied to political elections every four years. Of the customers who move, about 80% relocate within the service territory. For purposes of this analysis, we assume that 80% of the 25% of the population who relocate each year move elsewhere within CECONY's service territory, while the remaining 20% (or 5% of the total population) are first-time CECONY customers who come from outside the service territory.

If CECONY (or any utility for that matter) had to replace 25% of participants to maintain steady enrollment using the same recruitment methods and incurring the same costs as were incurred to recruit customers onto the program in the first place, many opt-in programs would not be cost effective. Replacement costs would be too high relative to the benefits, especially for a population like CECONY's where average load impacts are relatively small because overall usage is small (due to the high percentage of customers in relatively small, multi-family units). For this reason, we assume that most utilities, including CECONY, would modify their business practices to allow for tracking of customers who already enrolled on a TOU rate and who move elsewhere within the service territory so that when those customers sign up for service at their new location, they would be offered their prior rate on a default basis. Given this assumption, there are no incremental costs to re-enrolling movers on the rate they had before under any of the pricing scenarios.

Even with these business practices in place, CECONY would need to replace 5% of the enrolled population each year with customers who move into the service territory. We assume that rate marketing will occur as part of the signup process for electricity service so there will not be any direct mail or other outreach marketing costs incurred for these replacement customers, nor will there be any incremental enrollment costs associated with switching rates since they will just be coming onto the rate for the first time. We assume that each newly enrolled customer will receive a welcome kit, at a cost of $2.50 per enrollee. We also assume that for the high opt-in scenarios, the marketing incentives of $25 and $50 (for the non-targeted and targeted scenarios, respectively) will still be offered to encourage enrollment onto the rate.

3.6.6 Recurring Engagement Costs

This cost category covers notification costs associated with CPP events as well as incremental CSR costs that some argue will occur when customers go onto TOU or CPP rates. These incremental bill inquiries and other customer calls might occur after heavy CPP event sequences or after the first bills of the summer, which might be higher under TOU rates compared with flat rates. Based on the SPO pilot, SMUD estimated that these costs would equal $0.98/enrollee for non-event related TOU rate inquiries per year, and $1.50/enrollee for event related inquiries. SMUD also estimated that notification costs per year equaled $1.65/enrollee for an average of 12 events per year per customer. The TOU-CPP tariff used in this analysis assumes an average of 10 events per year, which would reduce that cost to $1.37 per enrollee. In work done for OG&E referenced previously, Nexant obtained information from a notification vendor indicating these costs might only equal $0.10/event, or $1.00 per customer per year. Averaging these estimates, we assume that the average notification costs per enrolled customer for 10 events would equal roughly $1.20

3.6.7 Measurement and Evaluation Costs

The final assumed cost is associated with annual estimation of load impacts from the various rate options. We assume these evaluations would be contracted out to an independent evaluator and could be conducted for roughly $200,000 each year.

3.7 Miscellaneous Inputs

In addition to the enrollment and cost inputs, there are several other parameters that affect the cost-effectiveness calculations and must be specified by the user. Descriptions of these variables are presented in Table 3-10 along with the values used in the analysis.

Table 3-10: Miscellaneous Cost-Effectiveness Parameters

Parameter	Description/Purpose	Value
Overall Analysis Start	First year of analysis	2020
Overall Analysis Period	Length of analysis	20 years
Discount Rate (Nominal)	Rate at which future dollars are discounted back to current year	7.72%
General Inflation Rate	Annual rate at which all non-labor costs increase if not explicitly specified	2.10%
Labor Cost Escalation	Annual rate at which labor costs increase if not explicitly specified	2.10%
Reserve Margin Requirement	Amount of excess capacity needed for each network group	17.00%
Generation Capacity Escalation Rate	Annual rate at avoided generation capacity costs increase if not explicitly specified	2.10%
Transmission Capacity Escalation Rate	Annual rate at avoided transmission capacity costs increase if not explicitly specified	2.10%
Distribution Capacity Escalation Rate	Annual rate at avoided distribution capacity costs increase if not explicitly specified	2.10%

Transmission Line Losses	Power losses due to resistance	2.43%
Distribution Line Losses	Power losses due to resistance	7.3%

4 Results

This section presents estimates of the load impacts, benefits and costs associated with the specific TVP rate analyzed here and the five different enrollment scenarios described throughout this report:

1. Opt-in without targeting, low enrollment (5%)
2. Opt-in with targeting, low enrollment (5%)
3. Opt-in without targeting, high enrollment (15%)
4. Opt-in with targeting, high enrollment (15%)
5. Default (10% opt-out rate).

The section is divided into three subsections focusing on load impacts, cost effectiveness and a sensitivity analysis showing how net benefits vary with changes in key variables/assumptions.

4.1 Load Impacts

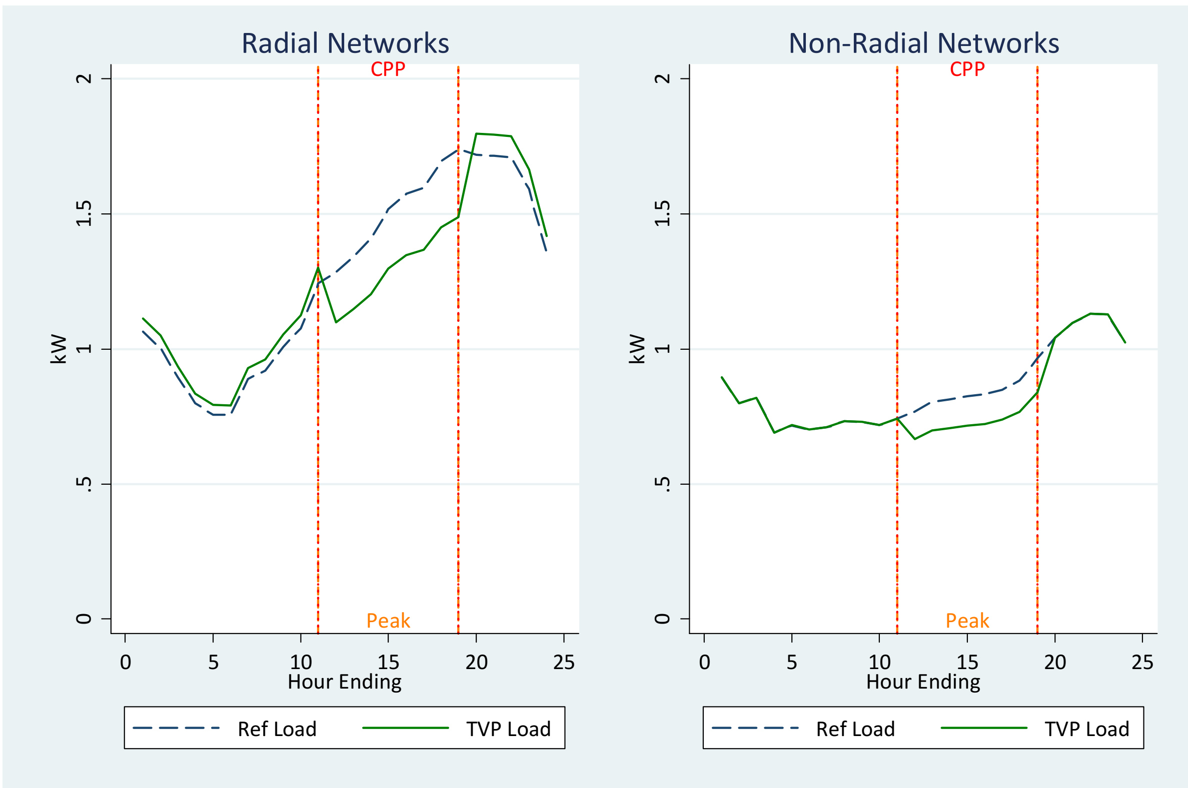
Load impacts in response to the hypothetical TOU-CPP rate were modeled at the individual customer level using a CES demand model and were then scaled up to the network group level for each enrollment scenario. Hourly load impacts were estimated for the average weekday (non-event days) in each summer month (when the relatively modest TOU price ratio is in effect) and for an average event day (when the much higher CPP adder is in effect during the peak period). As seen below, impacts are quite small on the average weekdays but are much larger on CPP event days. Because of this, essentially all of the benefits derived from this particular TOU-CPP rate are a result of the event day impacts. This should not be construed to mean that all TOU rates are ineffective in reducing peak demand. A TOU rate that did not include a CPP adder would have a much higher price ratio than the TOU-CPP rate analyzed here and would therefore produce larger impacts on the average weekday than what is seen below.

4.1.1 Per Customer Impacts

Peak period load reductions on the average weekday (excluding CPP event days) are quite small, equaling roughly 1% for both the radial and non-radial regions. There are several explanations for the small impacts. First, the magnitude of the TOU price signal is small, which is a direct result of the high CPP prices that are in effect on event days. Because the TOU-CPP rate was calculated to be revenue neutral, these high prices must be offset by lower prices in the off-peak and TOU peak periods. Second, weather conditions for the average weekday are relatively mild compared to event days, resulting in smaller EoS values (less peak-off-peak substitution) for these days compared to the event days. Finally, reference loads on normal summer weekdays are relatively low and do not provide much opportunity for load shifting.

Estimated load impacts on event days are substantially larger and range from 0.11 kW (12%) for the smaller average consumers concentrated in CECONY's network regions to 0.22 kW (14%) per customer for the larger, radial system regions for the opt-in enrollment scenarios.[48] These impacts are shown for the average customer in radial and non-radial networks without targeting in Figure 4-1. With targeting, the absolute impacts increase to 0.20 kW for the non-radial regions and 0.28 kW for the radial areas due to the assumption that targeted customers will have larger reference loads and therefore greater capability to reduce load.

Figure 4-1: Load Impacts on Event Days Without Targeting



The CES model incorporates reference loads, rate structure, prices, weather-sensitive price responsiveness and targeting to produce hourly load impact estimates for each month of the year. One aspect of time-varying pricing that is not directly accounted for in the CES model is whether the rate is offered on a default or opt-in basis. In addition to the obvious differences in enrollment that will occur under a default versus opt-in scenario, a more subtle consequence of the enrollment strategy is its effect on the average per customer impact. SMUD's SPO was the first pilot to explicitly test the efficacy of default vs. opt-in enrollment strategies on a side-by-side

48 Differences in the percent impacts are due to differences in Radial vs. Non-Radial reference loads and the unique structure of the TOU-CPP rate in the Tier 2 – Evening Peak network group that is dominated by residential load shapes and peaks around 9 pm.

basis. One of the findings from the SPO was that, on a per customer basis, opt-in rates resulted in larger impacts than when customers were defaulted onto the same rate.[49]

Like most other pilot programs testing time-varying rates (including BGE and PowerCentsDC), all of the rates in the CL&P study were offered to customers on an opt-in basis only. To estimate the impacts of defaulting customers onto a hypothetical TOU-CPP rate in CECONY territory, we adjusted the opt-in load impacts predicted by the CES model down by the ratio of default-to-opt-in impacts from the SPO pilot (the ratios used were approximately 0.625 for non-event days and 0.5 for event days).[50] Thus, the average load impacts per customer on CPP days for the default scenario equal 0.055 kW for the non-radial regions and 0.11 for the radial regions.

4.1.2 Risk-Adjusted Aggregate Impacts

The estimated per customer impacts discussed in the previous section are used as input to the cost-effectiveness model, where they are combined with enrollment assumptions and estimates of coincident peaking risk to produce aggregate risk-weighted peak load reductions at the distribution and generation level. The resulting estimates for each enrollment scenario are presented in Table 4-1.

Table 4-1: Risk Adjusted Load Reductions

Enrollment Strategy	Targeting	Risk Adjusted Load Reductions (MW)	
		Distribution	Generation
Opt-in Low (5%)	No	16	19
	Yes	11	13
Opt-in High (15%)	No	48	58
	Yes	33	40
Default (90%)	N/A	180	216

The load reductions in Table 4-1 are much lower than the aggregate load reductions that would occur as a result of time-varying pricing because they account for the overlap between when those reductions occur and when they are needed by the grid (as discussed in Section 3.2). Differences in the risk-adjusted load reductions are due primarily to differences in per customer impacts and aggregate enrollment. Opt-in scenarios have larger per customer impacts than the default scenario, but there are many more enrolled customers under a default rollout. Targeting further increases the per-customer load reductions, but results in an even smaller enrolled population since only a segment of the population is targeted. In the case of opt-in scenarios

49 Enrollment is much larger under a default scenario, so despite the larger per customer impacts, default rates still provided substantially larger aggregate impacts.

50 This ratio-based adjustment is similar to the adjustment made to account for customers in multi-family dwellings having smaller elasticity of substitution values than customers in single-family residences.

with or without targeting, the difference in load reductions is due entirely to aggregate enrollment.

4.2 Cost Effectiveness Results

Table 4-2 summarizes the cost effectiveness analysis for each of the five enrollment scenarios that are analyzed. As seen, the load impacts resulting from implementation of the specific TOU-CPP tariff analyzed here over the 20 year forecast horizon produce benefits ranging from a low of roughly $38 million in present value for the targeted, low opt-in scenario to a high of $625 million for the default scenario. The present value of benefits for the two targeting scenarios is roughly two-thirds of the value estimated for the non-targeted scenarios. The estimated costs of implementing TVP rates for each scenario over 20 years range from a low of roughly $29 million to a high of $193 million in present value.

Table 4-2: Cost-Effectiveness Results

Enrollment Scenario	Targeting Strategy	# Enrolled Customers	PV Benefits ($M)	PV Costs ($M)	PV Net Benefits ($M)	B/C Ratio
Opt-in Low (5%)	None	143,424	$55.5	$44.2	$11.4	1.26
	Top 2 Usage Quintiles	59,717	$37.7	$29.2	$8.5	1.29
Opt-in High (15%)	None	430,270	$166.6	$76.6	$90.0	2.17
	Top 2 Usage Quintiles	176,148	$113.1	$46.4	$66.7	2.44
Default (90%)	n/a	2,581,622	$624.7	$193.1	$431.6	3.24

Net benefits, the primary measure of cost-effectiveness, are positive in all scenarios and range from a low of $8.5 million for the opt-in, low scenario with targeted marketing to a high of $432 million for the default scenario. The benefit-cost ratio ranges from 1.26 to 3.24. An aggressive and effectively marketed opt-in program that achieves a 15% enrollment rate is estimated to produce significant net benefits of roughly $90 million in present value based on the tariff and assumptions analyzed here. Net benefits for the default scenario are almost five times larger than for the high opt-in scenario.

4.3 Sensitivity Analysis

In order to test the robustness of the results summarized above, sensitivity analysis was conducted to determine how net benefits vary with variation in key variables and input assumptions. The results are summarized in Table 4-3. For each variable in the table, net benefits were estimated based on values that are either 20% greater or 20% less than the values used in the base case analysis. This analysis was conducted for two of the five scenarios, the low and high opt-in scenarios that do not involve targeting. Results for the default scenario would be robust across any reasonable level of variation in any of the input values. Variation in net benefits for the targeting scenarios can be inferred from the results summarized below.

Table 4-3: Sensitivity Analysis for Key Variables on Opt-in Scenarios Without Targeting

Scenario	Variable	% Change	Benefits ($m)	Costs ($m)	Net Benefits	Benefit/Cost
Low opt-in (No Targeting)	Base Case	n/a	$55.5	$44.2	$11.4	1.26
	Enrollment	+20%	$66.6	$47.9	$18.7	1.39
		-20%	$44.4	$40.3	$4.2	1.10
	Price Elasticity	+20%	$66.0	$44.2	$21.8	1.49
		-20%	$44.9	$44.2	$0.7	1.02
	Price Ratio	+20%	$60.5	$44.2	$16.3	1.37
		-20%	$49.5	$44.2	$5.3	1.12
	IT Cost	+20%	$55.5	$47.2	$8.4	1.18
		-20%	$55.5	$41.2	$14.3	1.35
	Attrition Rate	+20%	$55.5	$44.2	$11.3	1.26
		-20%	$55.5	$44.1	$11.4	1.26
	Ongoing Recurring Cost	+20%	$55.5	$45.4	$10.1	1.22
		-20%	$55.5	$43.0	$12.6	1.29
	DM Costs	+20%	$55.5	$45.7	$9.9	1.22
		-20%	$55.5	$42.5	$13.0	1.31
High opt-in (No Targeting)	Base Case	n/a	$166.6	$76.6	$90.0	2.17
	Enrollment	+20%	$199.9	$86.9	$113.1	2.30
		-20%	$133.3	$66.4	$66.9	2.01
	Price Elasticity	+20%	$198.0	$76.6	$121.4	2.58
		-20%	$134.6	$76.6	$58.0	1.76
	Price Ratio	+20%	$181.5	$76.6	$104.9	2.37
		-20%	$148.4	$76.6	$71.8	1.94
	IT Cost	+20%	$166.6	$79.6	$87.0	2.09
		-20%	$166.6	$73.6	$93.0	2.26
	Attrition Rate	+20%	$166.6	$76.7	$89.8	2.17
		-20%	$166.6	$76.5	$90.2	2.18
	Ongoing Recurring Cost	+20%	$166.6	$80.3	$86.3	2.08
		-20%	$166.6	$73.0	$93.6	2.28
	DM Costs	+20%	$166.6	$78.3	$88.3	2.13
		-20%	$166.6	$75.0	$94.6	2.22

As seen in the table, both scenarios are robust across +/-20% changes in the seven variables analyzed. Two of the variables, the price elasticity and price ratio, affect the benefit estimate but not costs. Four of the variables, IT costs, attrition rate, ongoing recurring costs and direct mail costs, affect costs but not benefits. The final variable, enrollment, affects both the benefit and cost side of the net benefit equation.

Enrollment, the price elasticity of demand, and the price ratio have the largest impact on net benefits. Variation in IT costs has the most significant impact on net benefits among the cost variables, followed by direct mail costs. The attrition rate has little impact on net benefits.

5 Conclusions

This report summarizes a benefit-cost analysis for the implementation of a specific time-varying rate offered to CECONY's residential customers based on a variety of enrollment scenarios. These scenarios are based on CECONY's plan to deploy advanced meters to all customers by 2020. The net benefits range from a low of $8.5 million based on an opt-in scenario that would achieve 5% participation to a high of $432 million based on a default scenario where 10% of customers would opt-out. An opt-in scenario that assumes 15% enrollment, a level of participation that has been exceeded by several other utilities, is estimated to deliver $90 million in net benefits. In our opinion, these net benefits would not be possible without full scale deployment of AMI. The estimates provided here are based on empirical research from pilots and programs conducted elsewhere and may be conservative in that they do not factor in the potentially significant impact of enabling technologies on demand response nor do they consider impacts for non-residential customers or from energy savings (as opposed to capacity savings) that can occur when TVP is deployed.

Appendix E. Benchmark

conEdison

Advanced Metering Infrastructure Benchmarking Report

October 15, 2015

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Figures

Tables

1 Introduction

To support its Advanced Metering Infrastructure (AMI) project, Con Edison is employing a variety of best practices including conducting a benchmarking study of peer utilities to build understanding and gather lessons learned. Since many peer investor-owned utilities have already implemented AMI, Con Edison is in a strong position to leverage those lessons learned for the benefit of its customers.

The objectives of this benchmarking report were as follows:

- Gather data from peers on practices contributing to AMI project success
- Highlight impediments and lessons learned
- Apply findings to Con Edison's project to leverage the experience of others to improve all phases of the project
- Establish a peer utility group to use as an ongoing resource throughout the AMI project lifecycle

These objectives were met through a combination surveys, interviews and secondary research through public documents, such as Public Service Commission and utility websites. As is typical with such studies, varying degrees of information were provided by the different utilities.

Prior to launching the benchmarking research study, the Con Edison team considered the selection of peer utilities which would provide the optimal array of experiences to support its effort. Characteristics such as number of meters, customer characteristics, urban/mixed typology, geographic distribution, combination of electric and gas services, and status of AMI deployment were all considered. Particular attention was directed toward learning from utilities that have implemented AMI in large urban areas. The following peer utilities[64] participated in this study which was conducted from April – June of 2015:

- Canadian Utility
- Eastern Utility
- Midwest Utility
- Southern Utility
- Texas Utility
- Western Utility

Table 1-1 summarizes the characteristics of the benchmarking utilities, and also captures the status of their AMI programs and system deployment.

[64] Identities were masked at the request of participating utilities to protect confidentiality.

Table 1-1 Benchmarked Utilities

Utility	Percent Installed: Electric	Percent Installed: Gas	Install Start/ Completion Dates
Canadian Utility	79%		2013 / 2018
Eastern Utility	97%	100%	N/A/ 2015
Midwest Utility	18%		2014 / 2018
Southern Utility	100%		2007 / 2013
Texas Utility	100%		2010 / 2014
Western Utility	100%	100%	2007 / 2015[65]

1.1 Research Approach & Reporting

A three-phase research approach was used and started with developing a standardized survey instrument for completion by the peer utilities. This survey was divided into the following four topical areas:

1. Background & Business Case
2. System, Operations & Technology
3. Meter Installation
4. Organizational Change Management (OCM) and Customer Engagement (CE)

The distribution across topics was designed so that staff at each utility with deep content knowledge in each area could complete that section.

Following completion of the survey, Con Edison conducted follow up phone interviews with staff to either clarify or expand on input provided. In all cases, secondary research was necessary to augment information provided directly by the peer utilities.

This report is organized by the four topical areas referenced above and preceded by an Executive Summary.

65 The California Public Utilities Commission Annual Report to the Governor and the Legislature (January 2015) reports that AMI rollout is complete with remaining smart meter installations transferred to operations (page 12).

2 Executive Summary

2.1 Introduction

Con Edison is seeking to leverage the many lessons learned from peer utilities. At the outset, it is vital to understand that smart meter deployment is fundamentally about customer empowerment; that is, smart meters constitute the technology platform for a variety of features that enable customers to become active energy consumers. In every aspect of the project – from business case, definition of benefits, and technology options through vendor selection, meter installation, and customer engagement— Con Edison obtained valuable knowledge through this benchmarking effort.

The results of the surveys and discussions with the peer utilities were encouraging. All of the benchmarked utilities are now realizing success in many aspects of their AMI programs and are achieving a high level of performance. However, there are several lessons learned, which, if heeded, will enable Con Edison to realize the promise and avoid some of the pitfalls other utilities encountered as they navigated the AMI learning curve.

Peer utilities reported that customer acceptance of AMI is high as evidenced by very low meter "opt-out" rates coupled with increasing customer recognition of benefits in controlling their use and costs. In addition, for those utilities that reported on customer adoption of enhanced customer-enabling features, some are meeting goals and experiencing expanded customer interest as they learn the most effective engagement techniques.

2.2 Lessons Learned & Key Takeaways

The focus of this benchmarking effort was to gather lessons learned from peer utilities in order to inform Con Edison's approach across all aspects of its AMI project. These key elements for each of the four study areas are presented below.

2.2.1 Change Management

Based on Con Edison's customized benchmarking research, as well as other resources and experiences across the country, there are strong indicators regarding the importance of change management – both from a customer engagement and organizational change standpoint – as a key enabler of a successful smart meter project.

Figure 2-1 Benefits of Effective Change Management

As summarized in the accompanying diagram (Figure 2-1), this information results in a clear body of knowledge – and one that Con Edison is uniquely positioned to take advantage of due to the timeline of its AMI project.

2.2.2 Background & Business Case

The findings associated with examination of the business cases of the six utilities surveyed provide good insights into the acceptable process of building a business case for AMI.

Several of the benchmarking peers cited common benefits, which drove their business cases, as shown on the accompanying diagram (Figure 2-2).

All of these benefits figure prominently in the Con Edison business case and account for a significant share of Con Edison's benefits. Of interest are the varying magnitudes that each utility valued these benefits.

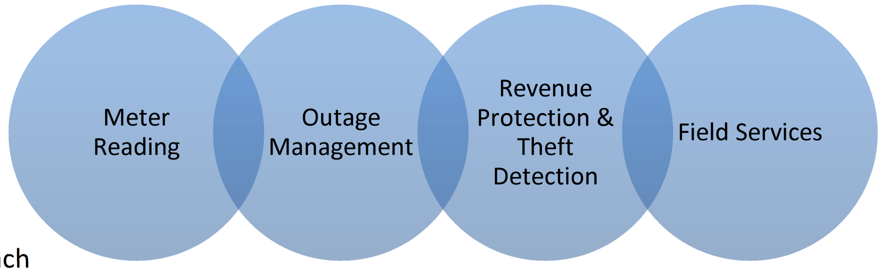


Figure 2-2 Common Core of Benefits

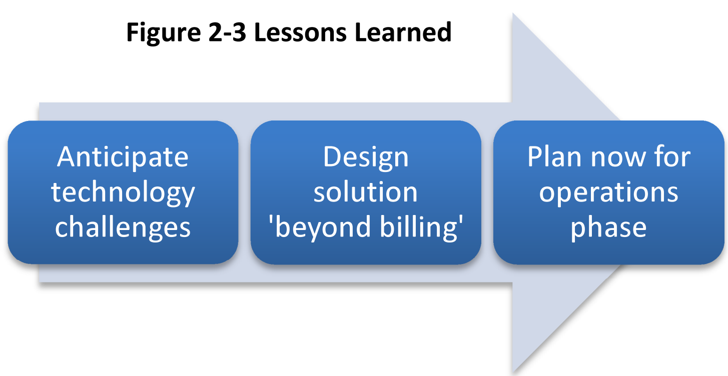
Based on the information gathered from these surveys as well as supporting information, the Con Edison AMI business case aligns with other utility business cases in a number of areas. However, Con Edison is positioned to deliver unique benefits to customers and stakeholders by implementing AMI, which is foundational to meeting New York State's Reforming the Energy Vision (REV) objectives. Con Edison also attributes a benefit due to Conservation Voltage Optimization (CVO), which will deliver considerable customer, societal and environmental benefits.

2.2.3 System, Operations & Technology

All of the peer utilities were successful in the deployment and operation of their AMI technologies and they are achieving a high level of performance. The utilities advised Con Edison to plan ahead for real-time requirements and data requests that result from the successful implementation of AMI.

Three key lessons learned are summarized in the accompanying diagram (Figure 2-3) and as follows:

Figure 2-3 Lessons Learned



- Each peer utility is experiencing better than 99% meter read rate from their AMI solution. Even with New York City's challenging environment, Con Edison should expect to achieve at least this performance. However, in-building coverage was a challenge for at least one utility and Con Edison should expect to encounter some challenges in areas such as Manhattan. Con Edison plans to manage the risk of communications system cost overruns by stipulating in its contracts that the AMI system vendor is responsible for the installation costs of additional communications equipment required to communicate with every meter. The AMI system vendors have agreed with this specification requirement.

- Con Edison should design and implement the technology and operations organization to support real-time data requirements and not just to support billing. All of the reference utilities first focused on billing functionality and many are now conducting pilots and implementing enhanced functionality beyond billing. One utility specifically identified challenges encountered while enabling real-time functionality and indicated that this should have been addressed at the beginning of the project. Currently, none of the benchmarked utilities are providing customers with access to real time usage information.
- Con Edison should begin planning for the operation of the AMI solution early. The benchmarked utilities were surprised at the overall workload and responsibility of the Smart Meter Operations Center. Con Edison should expect to staff its AMI operations center appropriately and will need to be prepared to provide data to external and internal users early in the schedule.

2.2.4 Meter Installation

The accompanying diagram (Figure 2-4) summarizes the three essential elements based on the experience of the peer utilities relative to meter installation.

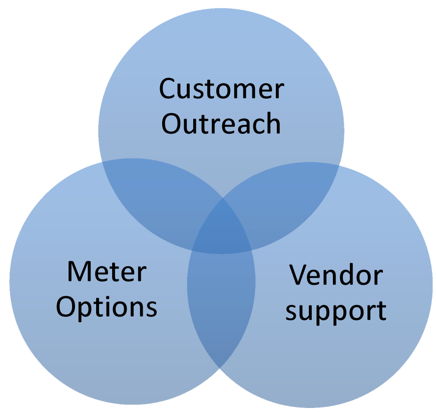


Figure 2-4 Meter Installation Essential Elements

1. **Effective customer outreach.** Community awareness and a preemptive public communications plan were essential to the success of the project. Consistent messaging on topics from RF safety to data security and privacy reduced public and regulatory commission concerns, thus allowing the project to proceed with minimal "opt-out" impact. Average "opt-out" rates for peer utilities were less than 1% with reported rates ranging from .0003% to 1%.

2. **Meter Options.** All but one of the responding utilities were required to or developed "opt-out" programs for customers who chose not to receive smart meters. These programs included customer communications on participation in the "opt-out" program and the cost of participation. Other considerations given by the utility included the realization that a non-communicating meter could impact the network as designed depending on the technology. This was particularly the case in areas where the potential for non-participating customers was higher than expected.

3. **Meter installation vendor (MIV) planning support.** Emphasis should be placed on working with the meter installation vendor to optimize route planning for both gas and electric meter deployment.

In addition, research revealed that the MIV should reduce most, if not all, manual operations during the installation process (e.g., manual entry of the current meter reading or GPS data).

3 Change Management

3.1 Introduction

The Con Edison AMI project is using the term Change Management (CM) as an overall term for the project's critical people and process factors. CM consists of two elements, defined as follows:

- Customer Engagement (CE): Engaging internal and external constituents effectively such that they understand and endorse the AMI project, noting the need to remain agile to understand and address resistance
- Organizational Change Management (OCM): Identifying and managing the internal changes associated with AMI to support project success

For the utility industry, and technology projects in particular, change management is often cited as a key critical success factor; this trend was confirmed in comments by some of the benchmarking peers. The level of detail and rigor may vary, but the peers all engaged in some level of formalized change management effort. Overall, there was more information provided by peers and available through public sources (secondary research) related to customer engagement. As a result, the majority of this section addresses those findings.

Another notion that applies across the CM spectrum, which was noted by at least one peer and is well known by CM professionals: the people and process work is highly dynamic. As a result, decisions on direction made at the outset have to be constantly tested, validated and modified in order to stay synchronized with reality. To paraphrase one: "When the journey started five years ago, a lot of assumptions were made. Revalidation and redesign based on changing expectations and realities were essential."

This section presents findings of the benchmarking study relevant to both CE and OCM.

3.2 Lessons Learned & Key Takeaways

Table 3-1 summarizes key points made by each utility in relation to Change Management.

Table 3-1 Key Takeaways Related to Change Management

Utility	Main Emphasis	Lessons Learned & Key Takeaways
Canadian Utility	Outreach	Doubled the deployment speed to limit media impact and opposition In person sessions with municipalities and Councils very effective
	OCM	Recommend further planning related to OCM
Eastern Utility	Outreach	Leverage governmental affairs for network build-out
	OCM	Change agent network (5-20% Level of Effort was cited as effective to fulfill role) Attention to transition to operations important
Midwest Utility	N/A	No primary data provided
Southern Utility	Outreach	Attention to details results in lower customer complaints
	OCM	Strong leadership & governance is critical Plan early for people and process impacts Developed dedicated OCM team in Customer Ops
Texas Utility	Engagement	Web presentment of data has increased customer satisfaction Carbon savings: 33,000 truck rolls saved Start meetings with impacted staff early
	OCM	Several impacted processes, most modified but billing totally redesigned ~9 new operational positions identified
Western Utility	OCM	Do not underestimate OCM; prep lines of business that this is not a 'project.' but a permanent change to the way you do business.

3.3 Implications for Con Edison

Based on Con Edison's customized benchmarking research as well as information from other resources and experiences across the country, both customer engagement and internal change management are key enablers of a successful AMI project. Other resources include REV studies, Department of Energy Smart Grid Investment Grant summary documentation, multiple utility presentations at industry conferences, research by the Smart Grid Consumer Collaborative, and knowledge leveraged by AMI Subject Matter Experts.

Based on the information obtained, the following are recommendations:

- Start change management early in the project lifecycle, not as an afterthought

- Develop a clear strategy up front and implement with focus, including fundamental decisions regarding how AMI may expand the relationship with customers
- Provide adequate change management resources
- Link change management efforts to the master project schedule
- Keep change management efforts ahead of the project curve – avoid information gaps and never surprise customers
- Provide information using multiple vehicles (traditional, electronic, social, etc.) and build in interactive outreach methods
- Align customer outreach efforts with other utility initiatives to provide cross marketing impact and opportunities for increasing returns
- Practice timely and transparent communications principles, both internally and externally

3.4 Detailed Findings: Customer Engagement

As utility deployments of advanced metering projects approach reaching 50% of American homes[1], Con Edison is in the advantageous position of adopting AMI after similar projects have been completed and understanding of the marketplace and customer response has matured.

In addition, there are multiple information resources, such as the Smart Grid Consumer Collaborative (SGCC) and the Edison Foundation Institute for Electric Innovation (IEI), that provide valuable research into customer perceptions, as well as insight into customer behavior. Early adopters learned some difficult lessons about how and when to engage customers, stakeholders, and the approach is now clear: *Engage early, often and factually through multiple channels with a focus on customer benefits*.

Overall, Con Edison already employs best practices in customer engagement on a variety of topics and programs; this practice will continue throughout the smart meter effort. In addition, like all of the peer utilities, Con Edison has a comprehensive customer outreach team and practices communications across multiple channels in order to reach a broad audience.

3.4.1 Engagement Approach

The peer utilities designed and implemented comprehensive marketing communications and customer service response programs. The overall approach and tone noted was clear, direct and factual; this is particularly notable in the information disseminated about meter installation and any associated concerns customers may have. As expected, they used a multiple channel engagement approach, which included print, broadcast, electronic and social media, as well as some unique outreach methods, and in-person methods; these are discussed further below.

3.4.1.1 Communications Theme/Benefits

As mentioned previously, the Con Edison AMI project has the benefit of leveraging experiences of others. In this regard, studies by the Smart Grid Consumer Collaborative have revealed common themes.

[1] According to the Edison Foundation Institute for Electric Innovation (IEI), as of July 2014, over 50 million smart meters had been deployed in the U.S., covering over 43 percent of U.S. homes.

Their national research has shown consumer agreement that the benefits of smart metering are important and desirable, as shown in Table 3-2.[2] As the industry continues to mature, the market will continue to evolve. In addition, IEI 2014 research confirms that utilities are experiencing benefits in system integration, operational savings, distributed energy resource integration and enhanced customer services.

	TOTAL IMPORTANCE*	Important, but at no additional cost	Important, willing to pay more, but unable at this time	Important, and will pay more
RELIABILITY A smart grid senses problems and reroutes power automatically. This prevents some outages and reduces the length of those that do occur.	86%	48%	20%	18%
ECONOMIC Smart grid help consumers save money by providing near real time energy usage information and the ability to manage electricity use.	86%	49%	22%	15%
ENVIRONMENTAL Smart grid reduces greenhouse gas emissions by making it easier to connect renewable energy sources to the electricity grid.	89%	47%	22%	20%

* Sum of three importance responses to the right.

[2] Smart Grid Consumer Collaborative research: Consumer Pulse Wave 5.

Table 3-2 Benefits of Smart Metering

Building on these industry-wide trends, specifics cited by the benchmarking peer utilities include employing consistent language and messaging, which is a marketing communications best practice. Table 3-3 summarizes these findings.

Table 3-3 Summary of Branding & Messaging

Utility	Name	Key Messages/ Benefits
Canadian Utility	Next-generation meters	'A reliable technology to better serve you.' Many customer benefits – real time readings; move in/out; outage restoration; meters at end of lifecycle
Eastern Utility	Smart Meters	Reduce energy use; save money; help environment; improve service. Integrated with City's 'smart future' initiative.
Midwest Utility	Smart Grid/ Smart Meters	Energy management; high usage alerts; manage usage & bills; fewer estimated bills; help eliminate meter reader visiting your home. Integrated with broader utility customer outreach campaign.
Southern Utility	Smart Grid/ Smart Meters	Control; convenience; reliability/outage response; efficiencies helping keep bills low; enhanced customer service.
Texas Utility	[Service Marked Name] Smart Meters	"…saving energy, money and the environment." Understand/manage/control use; make informed choices; save money; great for environment. Connects with statewide Smart Meter initiative.
Western Utility	SmartMeter™	Increased service/reliability; informed/smarter choices – control of costs; active energy participants; reduced carbon footprint
Con Edison	Smart Meter	Specifics under development; overall focus likely on customer control with minimal branding and nested in Digital Customer Experience initiative. Have started socializing terms and benefits.

The basic communications have settled into variations of only a few dominant benefit themes:

- Control/choice over use and costs
- Enhanced service
- Help the environment

These themes are then expanded into a list of customer-enabling features, such as:

- Remote meter reading
- Enhanced customer service
- Remove connect/ disconnect
- Outage notification/ restoration
- Energy efficiency
- Innovative products and services
- Home Area Networks
- Rate Options (Time of Use/Critical Peak)
- Demand Response

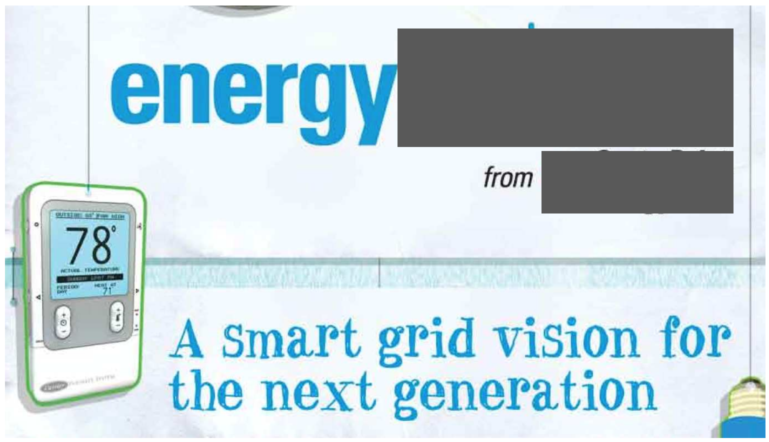


Figure 3-1 Sample Brochure

Moreover, some of the recent information on various utility websites highlights the future vision and emerging possibilities enabled by smart meters, such as the messaging throughout a brochure published by the Texas Utility (Figure 3-1). An example is the statement, ‘In smart homes of the future, consumers will be able to remotely monitor and control appliances.’

3.4.1.2 Communications Methods Used

The discussion below focuses on specific examples, which are noteworthy approaches from the information researched.

3.4.2 Engagement Methods & Channels

As expected, peer utilities used a multiple channel engagement approach, which included print, broadcast, electronic and social media, as well as some unique outreach methods. In addition, some peers cited customer call handling and highly individualized escalation approaches.

One-on-one communications, presentations, group meetings and event participation was mentioned frequently as a core communications practice.

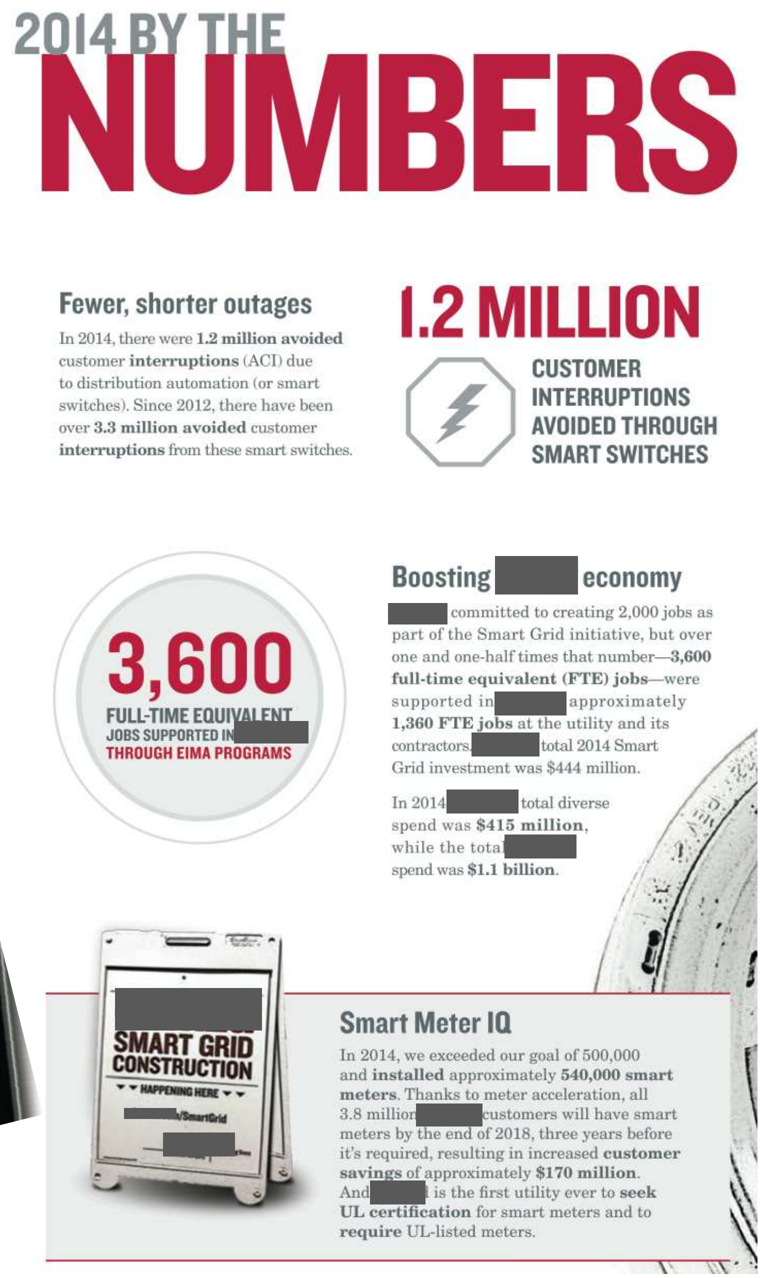
Figure 3-2 Utility Websites – Central Resource for Project Information

First and foremost, utility websites are the central resource for project information (see Figure 3-2). These websites included everything from interactive maps to keep customers up-to-date on meter deployment – plus links to programs for those with meters already installed – as shown in the accompanying image to promotion and tutorials on enhanced features such as customer portals. Other best practices include up-to-date FAQs, fact sheets and videos on the entire range of related topics. Fact sheets on the areas of concern – privacy, security, radio frequency emissions – are important.

Overall, the peer utilities used a consistent approach and tone in their communications with customers and stakeholders.

Peer utility home pages sometimes featured information on the smart meter program rather prominently, while for others, related information was a few clicks away.

Infographics are being effectively used across industries as a way of synthesizing and presenting summary information quickly and effectively. The smart grid industry is no exception with extracts of one piece developed by the Midwest Utility shown in Figure 3-3.



Testimonials have been used by some of the peer utilities; this is a proven communications strategy, and particularly useful when establishing initial momentum for support for the various phases and features.

In addition, some of the peer utilities used mobile or fixed outreach stations to provide a hands-on experience for customers and other stakeholders. The Texas Utility energy center (Figure 3-4) is one such example; the purpose is to "… demonstrate the future of electricity for public officials, state and federal regulators, other utilities, and consumers."

Figure 3-4 Texas Utility's Energy Center

Peer utilities report that these experience centers have been powerful tools for engaging constituencies such as customers, local elected officials and members of the public. They were often developed in partnerships with others, including local academic institutions and local government, presumably to share cost, build understanding and engage key stakeholders for the future.

One utility noted that their governmental and external affairs organizations have a significant role, particularly in the early phases of building the network. Their role and community connectivity opened up a lot of avenues, and peers cited using external affairs personnel on this piece proactively.

For the benchmarking peer utilities it is clear that the focus and effort involves explaining the benefits that AMI enables for customers. This also represents an industry-wide trend. Again, those benefits center on more customer control and opportunity to manage costs/save money.

3.4.2.1 Monitoring Effectiveness

In order to stay responsive to customer needs, utilities monitor communications effectiveness in a variety of ways, including statistically valid research. Recently, for example quoting *Smart Grid News*, a Texas Utility's comprehensive smart grid education program was recognized for targeting diversified ethnic and economic audiences. When surveyed, 60 percent of this utility's customers were able to name two or more benefits of smart meters. Plus, the utility has installed 99.9 percent of smart meters, clearly demonstrating how well educated and, ultimately, accepting of technology, its customers are.

3.4.2.2 Escalation Procedures

Customer concerns during meter deployment typically center on privacy, health, safety and cost. Peer utilities reported varying degrees of detail on this topic, but most had designed a thorough escalation process that was followed from day one. Those reporting on this process noted a similar approach relying on the outsourced Meter Installation Vendor (MIV) call center with escalation to internal staff for more challenging situations.

The early-adopting utilities were not as prepared for the degree and organized nature of customer concerns that arose, and mentioned the need to get ahead of the curve in this regard as an important lesson learned.

One example of an approach included the following steps as they worked through individual customer refusals:

1. Initial call to the MIV call center
2. Call center representative used scripted talking points to respond/address concerns
3. If not resolved, escalated to MIV supervisor
4. If still not resolved, escalated to utility
5. Utility follow up, including written communications
6. ‘Customer experience forums’ held twice per week to address issues as they were happening on a case-by-case basis; typically resulted in one-on-one contact with customer

Another utility noted that “attention to details resulted in low customer complaints.” In this case, utility staff reviewed every customer complaint and used the feedback gathered to shape strategy future strategy. They also proactively flagged billing variations.

Whether or not a utility offers an option for customers to ‘opt out’ directly impacts the nature and extent of the escalation procedures.

3.4.3 Meter Installation Outreach, Timing & Results

Communications during meter deployment is the crucial first step in establishing credibility with customers and establishes a new approach to the entire customer experience. Table 3-4 summarizes the information shared directly by the peer utilities.

Table 3-4 Overview of Meter Deployment Outreach

Utility	Deployment Info on Website?	Smart Meter FAQ's/Website Developed	Meter Installation Awareness
Canadian Utility	Yes	Yes	Local newspaper, letters 30 days prior to install, door hangers at install
Eastern Utility	Yes	Yes	No Data Provided
Midwest Utility	Yes	Yes	Mailings and additional info provided 30 days prior to install
Southern Utility	Yes	Yes	No Data Provided
Texas Utility	Yes	Yes	PUC required door hangers Posted 90 days before install
Western Utility	Yes	Yes	No Data Provided

Several different approaches were taken with communications awareness regarding meter deployment and installation. Most often, the media was made aware of deployment and mailings and/or "door hangers" were used as a reminder of the upcoming meter installation. In some cases door hangers where deployed prior to installation allowing customers to "opt-out" with ample time to make the arrangements or contact the utility.

The Eastern utility cited the following meter installation notification process:

- 45-day letter
- 21-day letter
- 1-day IVR notification
- Field visit and door hanger

Other efforts included mobile demonstrations, regional presentations, and outreach programs that covered some if not all the following.

- Information Privacy
- RF Safety and Emissions
- Data Security
- Smart Meter Installation Process
- Smart Meter Benefits
    - Energy Awareness
    - Smart Meter capabilities
    - Home Area Networks

Table 3-5 Advanced Metering Infrastructure Rollout

IOU (as of Oct. 2014)	Opt-out	Customer Complaints (escalated) [21]	Total Number of Electric Smart Meters (millions)
PG&E	51,622[22]	135	5.4
SDG&E	2,569[23]	5	1.4
SCE	22,587	528	5

Source: IOU Smart Grid Annual Reports to CPUC, October 2014, and data provided by the IOUs

Although the specifics varied, the peer utilities noted a clear, consistent approach with communications sequenced and timed to increase the likelihood of customer awareness regarding meter deployment.

Although not part of the benchmarking peer group, NV Energy used a 90-60-30 approach, which consisted of education of employees and community leaders, followed by education of the community at large, and finally notification of customers within 30 days of meter installation. Some utilities use a more generalized approach to meter installation rather than setting a specific goal of notification within 30 days of installation.

3.4.3.1 Meter Options & Communications

As detailed in Section 6 on metering, most of the peer utilities provided an optional non-AMI meter configuration for a fee. The one exception was in the case where a utility commission required full advanced meter deployment.

For those that did offer a meter option, the degree of proactive communication outreach was unclear from the responses; however, the research did reveal that some utilities called the optional meter an '"opt-out"' while others, such as the Southern Utility in the study group, used a more neutral approach simply referring to it as a "non-standard" meter option. This language also allowed the utility to reference the smart meter as the "standard meter", which normalizes the technology and allows messaging to position the smart meters more favorably, as shown in Table 3-6.

Table 3-6 Communications on Meter Option

BENEFITS AND FEATURES	SMART METER	NON-STANDARD METER
Access to the Energy Dashboard, to view your energy use by the hour, day and month	✓	✗
Convenience of remote meter reading—no estimated bills for hard-to-reach meters and no more waiting for someone to come to your home	✓	✗

3.4.4 Enhanced Features Outreach, Timing & Results

Based on the premise that smart meters create a new way to interact with customers and enhance the ability for a utility to provide customer-enabling tools and services, we gathered information from some of the peers on one such program. Rate and pricing options such as time of use (TOU), critical peak pricing (CPP) are two of the options that utilities are pursuing.

3.5 Detailed Findings: Organizational Change Management

Peer utilities provided limited information on OCM. However, even though details were not provided, some of the peers emphasized the need for timely and deliberate OCM as a key to project success. Most indicated that initiating OCM early in the process was a best practice. Most would have started earlier had they known this up front.

3.5.1 Internal Change Management Approach

All of the peer utilities employed OCM practices, with some more formalized than others. It appears that OCM was internally led, frequently with consulting support. One noted that a third-party, unbiased viewpoint was valuable.

Table 3-7 summarizes the OCM approach used by the peer utilities.

Table 3-7 Summary of OCM by Peer Utility

Utility	Methodology	Staffing	Comments
Canadian Utility	No specific method used	1 Internal lead	Integrated operational team; constant communications
Eastern Utility	Consultant[3]	1 Internal lead; consultant support	Created a Change Agent Network with reps across business units
Midwest Utility	Data Not Provided		
Southern Utility	Prosci[4]	1 FTE on AMI team; consultant support	Dedicated OCM group now in Customer Ops. 800 impacted employees
Texas Utility	---	Embedded in PMO	Formed a Process Change Team
Western Utility	Data Not Provided		
Con Edison	Standard (e.g., Prosci)	1 FTE on AMI team; other TBD with consultant support	Will build on lessons learned from ERP/other projects

[3] Consultant support was sometimes noted as crossover with other AMI project work; for a couple of the peers Accenture was specifically noted.

[4] Prosci provides change management research, tools and trainings (prosci.com).

A notable approach cited by several of the peer utilities involves creating a change agent network with representation from across the organization. This enables the flow of information to and from the project, and has clear organizational benefit. One utility cited that the change agents identified for the AMI project had a 5% to 20% level of effort as a secondary job responsibility during the project lifecycle.

One utility noted that they would have relied less on a large consulting team and more on building internal resources to build internal capacity and align more seamlessly with the corporate culture.

3.5.2 Impacted Departments

The eastern utility noted the natural flow and synergy from business requirements to inform OCM; this represents a common practice.

Peer utilities noted changes primarily in the following functions:

- Customer Operations
    - Customer Service
    - Billing
    - Collections
    - Meter Operations
- Information Technology (IT)
    - Analyst positions related to data collection and analytics

The Texas utility noted that AMI impacts core utility business practices, such as billing, asset management and customer engagement. As a result, a number of new skills were required as a result of the AMI project, and that they worked collaboratively with their Human Resources department to post and fill positions internally as possible.

One utility shared a thorough list of steps taken to address needs of impacted departments and employees:

- Start informational meetings with impacted employees at very beginning of the project
- Set up a process to help employees with resume building, interviewing skills and training
- Provide updates to impacted employees at least once per month

3.5.3 Business Process Changes

The Canadian utility specifically noted the following changes:

- Metering – process redesign
- Invoicing – process modification
- Collections – process redesign
- Outage procedures – process modification

3.5.4 Organizational Changes During Project Phase

It appears that most of the peers created a dedicated team for project development. These teams were interdisciplinary.

3.5.5 Organizational Changes During Operations Phase

One overall comment made was that a realistic assessment of operations and resources requires attention earlier in the project lifecycle than might be expected. The transition to business-as-usual requires attention in order to avoid surprises. This includes dovetailing with business processes outside of AMI, such as finance, legal, IT, communications, supply, and operations.

One utility noted that the new skill sets identified during the project were transitioned to operations as the project was completed. Another noted that clearly delineating transition to operations for details such as which department pays for meters during transition from deployment to operations.

4 Background & Business Case

4.1 Introduction

Over the last 10 years advanced metering has evolved from an optional technology to one that is widely deployed across the industry. There are many reasons for this trend, but the basic motivator is enhancing customer choice and control. In addition, utilities aim to perform existing operations more reliably and efficiently and provide enhanced customer services and products that are not possible without AMI technology.

From a slightly more granular level, the drivers for AMI are shown in Figure 4-1.

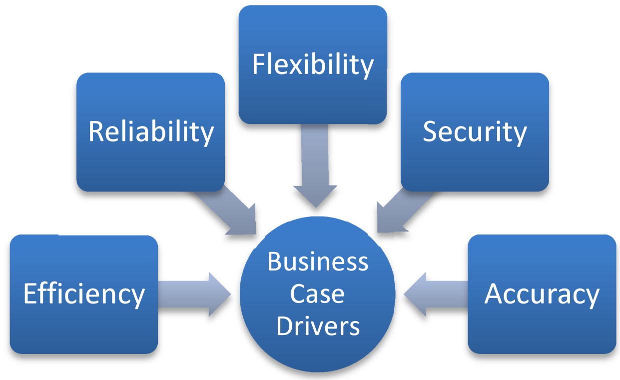


Figure 4-1 Business Case Drivers for AMI

Some specific examples of each of these main drivers are as shown in Figure 4-2 below.

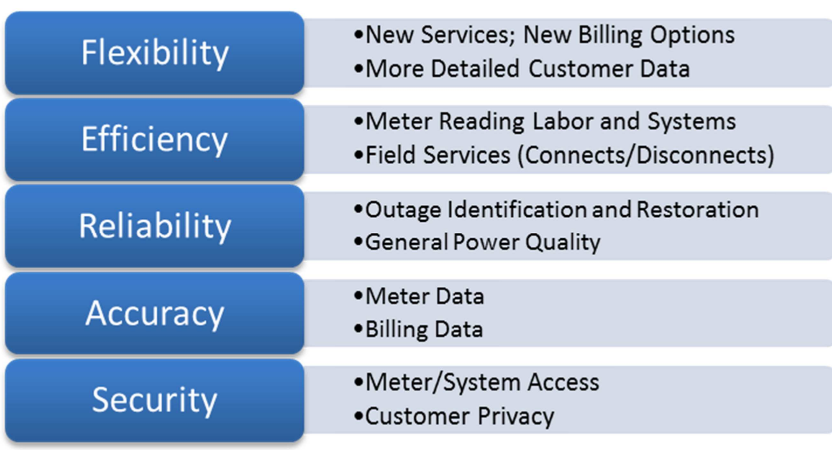


Figure 4-2 Specific Examples of Main Drivers

What has also changed is the type and manner in which benefits are quantified. Traditionally, business cases have focused strictly on benefits that produce hard financial results for the utility. Today business cases focus on a broader set of benefits that increasingly highlight the numerous customer, societal and environmental benefits enabled by AMI.

The focus of this section is to compare the Con Edison business case and cited benefits with those of other utilities that are further along in their implementation and benefit realization processes. This will allow Con Edison to:

- Validate proposed benefits
- Identify benefits not initially considered
- In some cases, compare originally proposed benefit magnitude with actually realized benefit

4.2 Lessons Learned & Key Takeaways

The findings associated with examination of the business cases of the six utilities surveyed provide insight into the process of building a business case for AMI. A summary of the primary drivers as listed in the surveys for these utilities is included in Table 4-1.

Table 4-1 Primary Drivers Cited by Peer Utilities

	Midwest Utility	Texas Utility	Southern Utility	Canadian Utility	Eastern Utility	Western Utility
Meter Reading	x	x	x	x		x
Outage Management		x	x	x	x	x
Revenue Protection/Theft Detection	x	x	x			
Field Services	x	x	x		x	x
Uncollectables	x					
Home Area Network						x

Figure 4-3 presents the common core of benefits that can be derived from these surveys.

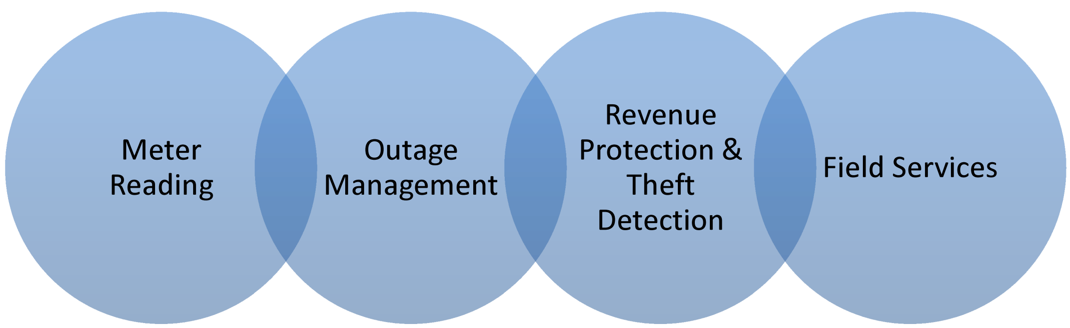


Figure 4-3 Common Core of Benefits Cited

All of these benefits figure prominently in the Con Edison business case.

4.2.1 Meter Reading

The valuation of the Meter Reading benefit was significant across all utilities surveyed with the exception of the Eastern Utility. Since the Eastern Utility had an AMR system prior to AMI they were already experiencing savings by automating meter reading functions. To offset this situation, the Eastern Utility used the cost to maintain the AMR solution as an avoided cost in the business case.

4.2.2 Outage Management

All utilities cited some Outage Management benefit. While the Midwest Utility did not count it as one of their primary drivers, they did include it in their overall business case.

Outage Management also has a significant “soft” benefit associated with increased customer satisfaction. Most utilities did not appear to quantify this benefit for the actual business case. However it was obviously a significant driver for the Texas Utility, as well as the Southern Utility given their frequent experiences with severe weather such as hurricanes. The business case for Con Edison took severe weather events into consideration by evaluating the Mutual Assistance costs as well as internal labor associated with major weather events.

4.2.3 Revenue Protection/Theft Detection

There was a wide range in benefits claimed for Revenue Protection. The Midwest Utility's business case consisted of two categories of Revenue Protection. One category was for Consumption on Inactive Meters (CIM) and the other was Unaccounted for Energy (UFE).

4.2.4 Field Services

The Field Services benefit covers field visits other than regular meter reading, such as customer turn-ons. To a certain extent this benefit is dominated heavily by the utilization of a remote meter service switch.

In virtually all cases, utilities claimed benefits and efficiencies associated with a remote service switch. This is in part due to the fact that meter vendors have been able to meet the market needs and requirements. Originally remote service switches were a separate device installed between the meter and the socket. This required duplication of electronics and packaging to support the switch operation. With the integration of the service switch into the meter and at a reduced cost, the investments have become much more readily justifiable.

4.3 Implications for Con Edison

Based on the information gathered from these surveys as well as supporting information, the Con Edison AMI business case aligns with other utility business cases in a number of areas; however, the Reforming the Energy Vision benefits that would be realized from an AMI deployment in Con Edison's service territory is unique and provides even more benefits as compared to the utilities benchmarked. Additionally, Con Edison has identified Conservation Voltage Optimization as a significant benefit and incorporated the implementation of CVO into its AMI roadmap. Conservation Voltage Optimization (CVO) benefits were not originally considered by peer utilities but are being investigated now.

4.3.1 Contingency Management

Contingency Management leverages the AMI network to control distribution assets or meter service switches to mitigate the risk of distribution system emergencies. None of the utilities surveyed had considered it as part of their business case. However, the Texas Utility reports that they are beginning to consider the option.

4.3.2 Conservation Voltage Optimization (CVO)

CVO is another relatively new concept that is receiving some significant attention. The only utility active in the implementation of this capability is the Eastern Utility. They noted results of being able to reduce voltage by 1% at 87 substations. Whether or not this capability was part of the Eastern Utility's initial business case is unclear.

The Western Utility has received funds from their Public Utility Commission (PUC) to investigate CVO. However, it was not part of their overall AMI business case.

4.3.3 Customer/Societal Benefits & Time Horizon

The information provided in the survey provided very little insight into the considered customer and societal benefits for these utility business cases. Typical customer benefits considered are:

- Improved billing accuracy, no estimated bills
- Access to more usage information
- Faster response to outages
- Improved response to move-in/move-out needs

While each of these represent tangible customer benefits, assigning a value to them from the customer perspective is difficult. There was no information provided that suggested any of the utilities attempted to value these benefits.

4.3.4 Business Benefits & Time Horizon

There was little information provided regarding the realization schedules for business benefits. The Canadian Utility did note that they were realizing benefit in the areas of load management, theft detection, and demand response. Note that this statement was interesting in that these specific benefits were not highlighted as their primary drivers for AMI.

The Eastern Utility received a grant to accelerate their AMI deployment in order to realize benefits more quickly.

The Western Utility provided some detail on their status by saying that they were “on track” to satisfy business benefits expected from their meter upgrade completed in 2013. Additionally they stated that they have a DR goal of 1000MW and that the PUC is looking for 10% DR capability.

4.3.5 Remote Service Switch Operation

A summary of the information gathered from the survey regarding operation of the remote service switch is summarized in Table 4-2:

Table 4-2 Remote Service Switch Operation

	Midwest Utility	Texas Utility	Southern Utility	Canadian Utility	Eastern Utility	Western Utility
Using Remote Switch	Y	Y	Y	Y	Y	Y
Door Knock Required?	N/A	N/A	N/A	N	Y	N

As can be seen from

Table 4-2 above, three utilities did not answer the question of whether a “door knock” was required prior to disconnecting service. Of the remaining three, only one of the utilities requires a physical communications attempt prior to performing a disconnect operation. The Western Utility’s response was the most interesting in that apparently no disconnect specific communications is required either in the form of physical presence, phone call, or paper correspondence.

These answers represent a changing stance with respect to remote disconnect/reconnect and the associated processes. Utilities employ various processes to attempt to receive payments prior to disconnecting service. These range from phone calls to paper communications to physical visits. Whatever the process, utilities typically have metrics showing the effectiveness of each step. Typically the last step can is very effective in the overall process. Some utilities mistakenly attribute that last action – whether it is a door hanger, phone call, or some other method – to be the impetus for payment. More likely, the last action is effective because it is the last action. Customers understand the process and may only react when the process reaches its last step.

The utilization of a remote service switch enables the utility to change that process in ways that cut cost and time. This is not to imply that utilities give less notice of impending disconnects. It simply means that the steps can be less labor intensive. The reaction to these process changes means that the customer will need to be retrained on the new process. The end result is that many utilities have seen more proactive payment habits because customers understand that the utility has the capability to remotely disconnect and no longer needs to be onsite or secure physical access.

5 System, Operations & Technology

5.1 Introduction

The successful AMI solution is an integration of metering and communication technology with several back-office information systems operated by an organization of personnel and processes. Con Edison will be installing nearly five million electric and gas meters to communicate with thousands of communications network devices and provide more than 1.6 billion meter readings every day through three new enterprise class information systems. The surveys and interviews of the six peer utilities indicated that the careful design and test of this integrated solution can result in a reliable and valuable technology with many benefits. However, the utilities referenced the challenges and surprises encountered from operating this complex solution of technology, systems and processes.

5.2 Lessons Learned & Key Takeaways

Table 5-1 summarizes the lessons learned and key takeaways from each of the peer utilities. In most cases, the lessons learned reflected the relative maturity of each utility's AMI program and technology.

Table 5-1 Summary of Lessons Learned

Utility	Lessons Learned & Key Takeaways
Texas Utility Status: Fully deployed; using data analytics for operational efficiencies	• Build meter farm on front end for testing. Also, build testing environments that mirror all services provided. Build process for updating production inventory as. • You cannot test enough. The hardware and firmware versions will change throughout the deployment period.
Eastern Utility Status: Fully deployed; Focus on DA and OMS	• Integration of new systems requires an agile approach during design and deployment • Distribution Automation systems integration maturity is continuing to evolve • HAN industry interoperability is continuing to evolve toward a reliable 'plug and play' solution • Deployment of advanced AMI system capabilities (e.g., remote connect/disconnect, third-party data access and web presentment) requires a critical mass of meters and a stable network

Utility	Lessons Learned & Key Takeaways
Midwest Utility Status: Initial Deployment	• No data provided
Southern Utility Status: Fully deployed; investigating enhanced services	• Mesh network is very stable even when there are issues with the 3rd party cellular communications. • Deploy a hybrid model of WAN communications to not rely on a single carrier • 99.5% read rate should be achievable • Data has to be part of your strategy. You will continue to evolve with new data analytics and approaches to mining the data • Information Technology group needs to be 24X7 to manage the infrastructure, customer portal, back end systems and all the critical interfaces
Canadian Utility Status: Near end of Deployment	• Had we had more time to set up the technological infrastructure, we would have chosen right from the beginning a dedicated storage and infrastructure named an "engineered system" like Oracle SuperCluster or backup appliances ZBA type. • The use of Flash cache and "high performance" storage cells technologies are very important when dealing with very high volumes of data that are produced and need to be managed. • In fall 2015, storage will be Oracle SuperCluster (Storage Cell) for the DB, backup and application files storage will be on Oracle "Appliance ZBA" and the SAN will no longer be used for AMI neither the application servers under HPUX (ITANIUM platform).
Western Utility Status: Fully deployed with focus on pilots and improvements	• We initially designed our AMI network and systems to support billing and are challenged to meet the real-time requirements of smart grid. • Challenging for AMI to do 'cool stuff' behind the meter due to bandwidth and latency (e.g., for DR since AMI network has other priority functions); also issues associated if device is far from meter (e.g., apartment buildings). CPP is manageable since it's a day ahead so no real time requirements. AMI essential for TVP/CPP. • Need to focus where you want to be regarding technology relationship with mass-market customers and partner with other providers, such as Comcast or Honeywell. AMI can be a channel, but does not have to be. • Strategic question: do you want to use AMI to expand relationship with customer? • Demand Response and Time based rates present some challenges that should be factored into the planning stages. • At the start of the program, we were already behind in delivering data to internal groups. We were surprised at the number of requests for data and tools. • You will never be done deploying meters. There are always new growth and coverage challenges. • Interval billing is challenging. Need to plan for dealing with exceptions and keeping up with exceptions. • Do not underestimate the field impacts. Although the failure rates are very low, with our volume, the field is always requiring support for their troubleshooting. • There's always room for improvement. Always building more tools to improve efficiencies. • There's always a need for tools. We thought that this need would ramp down over time. Be prepared with people to build tools and reports at the start.

5.3 Implications for Con Edison

The results of the surveys and discussions with the peer utilities were encouraging. All of the peer utilities were successful in the deployment and operation of their AMI technologies and they achieved a high level of performance. However, the utilities are also advising Con Edison to plan ahead for real-time requirements and data requests that result from the successful implementation of AMI.

- Each benchmarked utility is experiencing better than 99% data performance from their AMI solution. Even with New York City's challenging environment, Con Edison should expect to achieve at least this performance. However, in-building coverage was a challenge for at least one utility and Con Edison should expect to encounter some problems, particularly in dense urban areas such as Manhattan.
- Con Edison should design and implement the technology and operations organization to support real-time data requirements and not just to support billing. All of the reference utilities first focused on billing functionality and many are now conducting pilots and enhanced functionality beyond billing. One utility specifically identified challenges encountered while enabling the real-time functionality and indicated that this should have been addressed at the beginning.
- Con Edison should begin planning for the operation of the AMI solution early. The benchmarking utilities were surprised at the overall load and responsibility of the Smart Meter Operations Center. Con Edison should expect to staff the operations with about 30 employees and will need to provide data to external and internal users very early in the schedule.

5.4 Detailed Findings: Systems & Operations

This section details the findings of the benchmarking research and includes comparative information between utilities whenever possible.

The AMI solutions utilized by the six benchmarking utilities represent the four major AMI solutions from Itron (OpenWay™), Landis+Gyr (GridStream™), Sensus (FlexNet™) and Silver Spring Networks (see Table 5-2). The predominant electric meters selected and installed by the peer utilities were supplied by GE (General Electric) and Landis+Gyr and, typically, the supplier of the AMI solution will influence the electric meter that the utility purchases. Most of the peer utilities chose to use cellular communications for the backhaul communications to the AMI Head End Server (HES) with satellite radio for rural territories where cellular communications was unreliable or unavailable.

Table 5-2 Summary of Meters & Networks

Utility	Meter Type: Electric/Gas	Communication Network	LAN	WAN
Canadian Utility	Landis+Gyr	Landis+Gyr Gridstream	Wireless mesh	Cellular, Fiber with Satellite for rural areas
Eastern Utility	Landis+Gyr Sensus/Elster	Sensus FlexNet	Wireless point to multi-point	Fiber, microwave, WiMax
Midwest Utility	GE Landis+Gyr	Silver Spring Networks	Wireless mesh	Cellular
Southern Utility	GE Landis+Gyr	Silver Spring Networks	Wireless mesh	N/A
Texas Utility	Itron	Itron OpenWay	Wireless mesh	Private radio with Cellular backup
Western Utility	Landis+Gyr GE	Silver Spring Networks/Aclara Hexagram	Wireless mesh/Wireless point to multi-point	Cellular, with Satellite for rural areas

5.4.1 Performance Metrics

The responding utilities were unwilling to share performance information that could be easily associated with their utility operation. Overall, the utilities expected and achieved an operating performance well in excess of 99% and established performance thresholds and service level agreements, which were important to their users and the operating personnel. Subsequent contact with several AMI vendors validated that the AMI solutions for these reference utilities are operating in excess of 99%.

5.4.2 Communications Reliability

The peer utilities represent a cross-section of urban and rural environments and each indicated a clear bias on their choice of communications. Those utilities selecting an RF mesh solution felt that this solution was best able to meet their communications coverage and reliability challenges. The utility that selected a point to multi-point solution was replacing an existing point to point solution and felt that this solution was a better fit for their installation and was capable of providing communications coverage to rural and urban areas.

The responses on the communications reliability provide insight into some of the challenges with the rollout of an AMI solution. The detailed responses reflect the differences between an early adopter utility implementing an immature technology and a recent adopter utility implementing a more mature AMI technology:

- The communications is operating as expected, but the utility encountered several challenges during deployment of the solution.
- One early adopter utility stated that the solution was designed for billing and they are now encountering challenges to meet the real-time communications required by smart grid applications due to this limited design.
- The in-building penetration to communicate with some meters represented a challenge. However, each utility was able to overcome the challenges.

5.4.3 AMI Network Operations Center

The responses to questions and interviews regarding AMI Network Operations (or Smart Meter Operations) from the peer utilities were varied and represented the extremes of utilities with AMI solutions (see Table 5-3).

Table 5-3 Summary of Smart Meter Operations

Utility	Personnel	Operating Hours	Responsibilities
Canadian Utility	42 FTE All In-house operation	7:00 AM – 8:00PM M-F	• Monitoring endpoints and network • Control operations success • Upgrades and network security • Analysis of meter problems • User acceptance • Asset management
Eastern Utility	20 FTE Outsourced AMI HES	N/A	• Network monitoring • Endpoint monitoring
Midwest Utility	N/A[5] Outsourced AMI HES	Business hours	• NOC manages meters • IT manages comm network
Southern Utility	5 FTE Outsourced AMI HES	Business hours	• N/A
Texas Utility	8 FTE in Telecomm NOC All in-house operation	24x7	• Manages communication network
Western Utility	50 FTE Outsourced Electric AMI HES	5:30 AM – 6:00 PM M-F	• Front line group to support the basic monitoring and troubleshooting of endpoint devices and the network. • Advanced operations group is responsible for the advanced troubleshooting and provides supports for the many pilots and upgrades. • Operational support group is responsible for maintenance of business processes and building tools, reports and databases for internal and business users.

5 Based on various conversations, we remain unable to establish personnel counts for the Midwest Utility as they have not established a single, comprehensive AMI Operations group and have instead distributed that functionality among a number of different groups.

One utility is staffed at a very low level and relies on the outsourced AMI vendor to provide much of the monitoring and troubleshooting of the network. This utility is utilizing the AMI solution to mainly support simple billing.

The other peer utilities are staffed at a level between 1 FTE/100,000 meters and 1FTE/200,000 meters, which is a common staffing level for other large utilities. Several utilities are utilizing outsourced hosting services from their AMI vendors while others are operating the AMI solution internally, but all of these utilities are operating their other information systems (MDMS, CIS, MAMS, etc.) internally.

None of the peer utilities are running a 24x7 Smart Meter Operations, although the IT operations and telecommunications operations supporting the Smart Meter Operations may be 24x7. These operations groups do operate with an on-call staffing model to provide 24x7 response without 24x7 onsite presence. One utility indicated that, presently, the service level agreements do not require 24x7 operations, but as they add more smart grid applications this may change.

5.4.4 Meter Data Management System (MDMS)

The AMI solutions utilized by the six benchmarked utilities represent the major MDMS solutions, as summarized in Table 5-4.

Table 5-4 Summary of MDMS

Utility	MDMS Vendor	Functions enabled
Canadian Utility	Elster (EnergyICT)	• Data synchronization • Gateway to AMI for enterprise • Data warehousing
Eastern Utility	Oracle	• Meter reading • Data validation • Backfill results
Midwest Utility	Oracle	• N/A
Southern Utility	Itron	• Data repository
Texas Utility	Siemens (eMeter)	• Data synchronization • Data warehousing • Data validation • Data estimation • Event management • Data delivery to market (3rd parties) • Gateway to AMI for enterprise
Western Utility	Landis+Gyr (Ecologic Analytics)	• Data synchronization • Data management (Data warehouse is separate) • Data validation • Data estimation

5.4.5 Meter Asset Management System (MAMS)

None of the benchmarked utilities utilized or implemented a dedicated meter asset management system. Consequently, each of the utilities uses their existing ERP (Enterprise Resource Planning) system for inventory tracking, purchasing and order management and utilizes the AMI HES for simple asset management. Each utility had a slightly different perception of the role or function of a Meter Asset Management System and has implemented a Meter Shop Test Management system for managing the testing of meters and the tracking of test results. This MAMS information system is new to the AMI solution landscape with many utilities expressing that they are limited in the ability to manage the multitude of configurations and options provided by AMI meters.

Con Edison has a custom developed meter asset management system which manages the custody, physical configuration and testing of the legacy (non-communicating) meters and has been an industry leader with this level of asset management. The advancement of programmable communicating devices has forced Con Edison to work outside of this system with spreadsheets and separate databases for tracking this information. The new MAMS solution will provide Con Edison with the ability to manage all of the programs and complex configurations of the AMI meters as well as chain of custody and testing. With the new MAMS solution, Con Edison will be able to meet the expected needs of REV and new customer programs by enabling the re-configuration of endpoint devices to provide the data and control required by these applications.

5.4.6 Customer Information System (CIS)

Three of the six peer utilities have a commercial CIS from either SAP or Oracle and the other three utilities have a legacy mainframe CIS which required modifications to support AMI billing. None of the utilities mentioned any specific challenges or features with their CIS.

5.4.7 Data Presentment to Customer

Five of the peer utilities are currently offering data presentment to customers while the sixth is in the vendor selection phase; specifics are summarized in Table 5-5.

Table 5-5 Summary of Data Presentation

Utility	Portal Vendor	Functions Enabled
Canadian Utility	TBD	• Pilot underway • Will select portal vendor soon and enable data presentation
Eastern Utility	OPower	• Yesterday's data presented today
Midwest Utility	OPower	• Yesterday's data presented today
Southern Utility	Unknown	• Yesterday's data presented today
Texas Utility	Smart Meter Texas Portal	• Yesterday's data presented today • Green button enabled • Ability to grant others access to data • Support for in home displays (IHD) and programmable controllable thermostats (PCT)
Western Utility	OPower C3 Energy	• Yesterday's data presented today • Green button enabled • Customer notifications upon tiers exceeded • Linked with electronic bill presentment • Enabling data presentation using HAN and in home display (IHD) with about 3,000 customers online. • Separate data presentation for Commercial & Industrial customers

5.4.8 Systems Integrated with AMI Solution

Most of the peer utilities noted integrations with MDMS, CIS, OMS, and Customer Data Portal; specifics are provided in Table 5-6.

Table 5-6 Summary of AMI Solution Integrations

Utility	Integrations and Approaches to Distribution Automation
Canadian Utility	• AMI is fully integrated with MDMS, CIS, Customer Data Portal for meter data access and billing • AMI is integrated with OMS to support outage and restoration management • AMI is integrated with central security surveillance
Eastern Utility	• AMI is fully integrated with MDMS, CIS, Customer Data Portal for meter data access and billing • AMI is integrated with OMS to support outage and restoration management (Outage events reduced by 15 minutes and major outage durations reduced by 3 days) • Distribution Automation
Midwest Utility	• AMI is fully integrated with MDMS, CIS, Customer Data Portal for meter data access and billing
Southern Utility	• N/A
Texas Utility	• AMI is fully integrated with MDMS, CIS, Customer Data Portal for meter data access and billing • AMI is integrated with OMS to support outage and restoration management • AMI is integrated with the statewide Texas portal for customer data access and thermostat control operation • AMI data is integrated into distribution operations, but Distribution Automation operates through a separate network
Western Utility	• AMI is fully integrated with MDMS, CIS, Customer Data Portal for meter data access and billing • AMI is integrated with OMS to support outage and restoration management • Distribution Automation utilizes a different network solution and is separate from AMI • AMI utilizes ZigBee for communication of price signals • OpenADR integrations do not utilize the AMI solution

5.4.9 Business Intelligence/Analytics

Three of the four utilities reporting on this item noted that they are internally developing data analytics.

Table 5-7 Summary of Data Analytics

Utility	Data Analytics Vendor	Functions enabled
Canadian Utility	MDM	• Analytics where only meter data is required and easy to perform
Eastern Utility	N/A	• N/A
Midwest Utility	N/A	• N/A (Utility is still deploying AMI)
Southern Utility	Internally Developed	• Originally hosted for pilots • “Must plan for large data sets.” Analytics tools must be able to accept and utilize all of the data provided by AMI
Texas Utility	Internally Developed	• Theft of Service • Outage metrics and analysis • Voltage issues
Western Utility	Internally Developed	• Pilot projects funded by PUC for situational awareness • High and problem bill analysis • Internal operational tools and analytics • Customer service data warehouse for custom queries and assessment

5.4.10 Technology Infrastructure, Security and Testing

The AMI solution includes an infrastructure of applications, databases and servers which are tightly integrated to provide a complete and automated solution for collecting, processing and distributing the AMI meter data and alarms. The benchmarked peers maintained a rigorous, and somewhat standard, development and test process for the AMI solution, which would progress through 4 or 5 fully integrated environments (Test, Integration, Regression, Acceptance and Production). One utility reported constructing a “meter farm” to provide an end-to-end test environment from meter to billing.

Each benchmarked peer utility recognized the importance of security and data privacy with an AMI solution and has implemented encryption, firewall protections and policies consistent with their individual security and privacy standards.

6 AMI Meter Installation

6.1 Introduction

Although not all peer utilities responded to the meter installation questions, those that did summarized Meter Installation Vendor rollout planning as an area to focus on during the planning phase. As Con Edison develops the plans for the AMI rollout, the following items should be considered:

- Provide assistance for the meter installation vendor with deployment route optimization.
- Reduce most, if not all, manual operations during the installation process, such as hand entry of the current meter reading or capturing GPS data from a secondary device. The use of a single handheld tool to automatically capture as much information as possible was recommended.

Additionally, the importance of communications with customers was highlighted.

6.2 Lessons Learned & Key Takeaways

The benchmarking indicated project efficiencies and cost could be improved if utility personnel are engaged with the MIV meter installation deployment planning effort. (See Table 6-1). Emphasis should be placed on working with and assisting the meter installation vendor in day-to-day logistics for both gas and electric meter deployment.

Table 6-1 Summary of Lessons Learned

Utility	Main Emphasis	Lessons Learned & Key Takeaways
Canadian Utility	Deployment	Installers used handheld devices to auto capture installation data; paper and manual data entry solution was prone to error. Additionally capturing a picture of the install is recommended.
Eastern Utility	Meter Evaluation Gas Deployment Meter Installation Vendor	Used "external" assistance for meter evaluations. Project experienced delays due to gas leaks. Support Meter Installation Vendor in developing meter installation routes.
Midwest Utility		No data provided
Southern Utility	Deployment	Meter's located in below grade situations required creative solutions. SSN has been able to provide a solution.
Texas Utility	Lessons Learned	Need a dedicated team to deal with daily operational issues.
Western Utility		No data provided

6.3 Detailed Findings

Table 6-2 summarizes the AMI meters installed to date and planned. All numbers are approximate:

Table 6-2 Summary of Meter Installations

Utility	Installed to Date/Total: Electric	Installed to Date/Planned: Gas	Install Start/ Completion Dates	Approximate Cost per Meter (*)
Canadian Utility	3.1M / 3.9M	N/A	*2013 / 2018	$256
Eastern Utility	1.45M/ 1.5M	500K/500K	(N/A)/ 2015	$270
Midwest Utility	740K / 4.2M		2014 / 2018	$237
Southern Utility	4.7M / 4.7M		**2007 / 2013	$186
Texas Utility	2.3M / 2.3M		2010 / 2014	$290
Western Utility	5.4M / 5.4M	4.3M / 4.3M	2007 / 2015	$242

Notes on Table 6-2 are as follows:

> * Pilot was started in June of 2011 and ran through January of 2013.
> ** Installations started in 2007 with an initial installation of 50,000 meters. The utility waited one year to continue installations indicating that they waited to allow the product/technology to mature.
> (*) Benchmarking participants did not provide cost per meter. Estimates provided are based on available PUC filings or Smartgrid.gov project summaries.

6.4 Electric Meter Installation Approach & Statistics

Table 6-3 summarizes the meter installation rates and approach with a couple noting the use of staff to address non-routine installations.

Table 6-3 Summary of Installation Approach

Utility	Install Rate	Pilot Or Proof Of Concept	Staff Installation Utilized?	Staff Installation Type
Canadian Utility	10K per day with 330 Installers	Yes	Yes	No Data Provided
Eastern Utility	2.8-3.2K per day	Yes	No Data Provided	No Data Provided
Midwest Utility	3-4K per day Goal of 1M in 2015	No Data Provided	No Data Provided	No Data Provided
Southern Utility	4-5K per day	50K deployed and delayed	Yes	Non-routine C&I Installations
Texas Utility	5K per day at peak	No Data Provided	Yes	Non-routine and meters the contractor could not install
Western Utility	10K per day at peak			

6.5 Gas Meter Installation

Of the six utilities solicited for benchmarking information, two provided information related to gas AMI deployment. It was mentioned that additional support during the AMI meter deployment was required by utility personnel in instances where gas odors were detected and the detection of gas odors during peak deployment led to some delays. As a result of this requirement the utility experienced delays during peak deployment.

6.6 Meter Installation Vendor Overview

The installation process was identified as an area to focus on during the planning effort. The peer utilities indicated that the efficiency of the meter installation effort would be improved by having utility personnel support the MIV during the deployment planning and routing effort. It was also noted that that there is an Information Technology integration effort with the MIV work management software that needs to be planned for. Con Edison will incorporate this advice into its project plans.

6.6.1 Installations by Utility Staff

In nearly every case utility staff was required to support the MIV. Note that Con Edison also is considering using company forces to support the AMI rollout. It is planned for Con Edison’s workforce to install the high voltage (265 volt and above) C&I meters.

6.7 Meter Options and Approach ("opt-out")

Utility	"opt-out" [Required by Commission]	Fee to Install Optional Meter	Monthly Reading Fee	Opt –out Rate (% of total)
Canadian Utility	* Yes [Yes]	Yes $15 if notified by consumer; otherwise $85	$5.00	Estimated at 1%
Eastern Utility	No [No] AMI mandated by PUC	No Data Provided	No Data Provided	No Data Provided
Midwest Utility	** Yes [Yes]	No Data Provided	$21.53	Estimated at 0.5% or roughly 20K meters
Southern Utility	*** Yes [Yes]	$89 fee (reduced from $95 by order of the PUC)	$13.00	Reported at <1% (.0017) 6.5K out of 3.76M
Texas Utility	**** Yes [No]	Yes	$32.80	.0003% 70 out of 2.3M
Western Utility	*****Yes [Yes]	$75 "opt-out" fee. Opt-in at no charge	$10	.0095% 51.6K out of 5.4M as of 10/14

Table 6-4 Summary of Optional Meter Installations

* Additional "opt-out" information available at regulatory agency websites.
** No Data was provided in the peer survey. The State Commission issued a report that a fee of 21.53 will be paid on a monthly basis for opting out but further stated that no "opt-out"s will be granted after 2021.
*** No Data was provided in the peer survey. Data retrieved via research.
**** The Public Utility Commission of Texas did not adopt an "opt-out" Ruling until after the utility was fully deployed.
***** The utility was allowed to install a communicating meter but the radio had to be turned off. Consideration was given to the Network impact as the meter was considered to be part of the network. Other West Coast Utilities had a lower number of "opt-out" with the Los Angeles region having .0018% and the most Southern Utility having approximately .0045%.

With the exception of the East Coast utility an "opt-out" program was developed and administered by each utility. In the event the customer opted out of the RF meter installation, a monthly meter read fee was applied to the account in all instances. Further, several utilizes applied an additional charge for the installation of the "opt-out" meter if the meter was different that the standard RF meter being deployed, (i.e., did not contain an AMI radio). Where possible and permitted the radio was turned off and in those instances a monthly fee was again charged to manage the meter and account accordingly for non-participation in the AMI program.

Con Edison Advanced Metering Infrastructure Update

September 29, 2015

Tom Magee

Mike Murphy

Jamie Prettitore

conEdison

Agenda

- Welcome and introductions
- AMI customer benefits
- AMI customer portal
- Project status update
- Implementation plan
- Next steps

Smart Meters: Customer Choice, Control & Convenience

- **Empowers customers**
  - Manage energy use and costs
- **Enhances service**
  - Faster restoration and outage response
  - Eliminates estimated bills
- **Helps the environment**
  - Reduces carbon footprint
  - Encourages customers to become wise energy users

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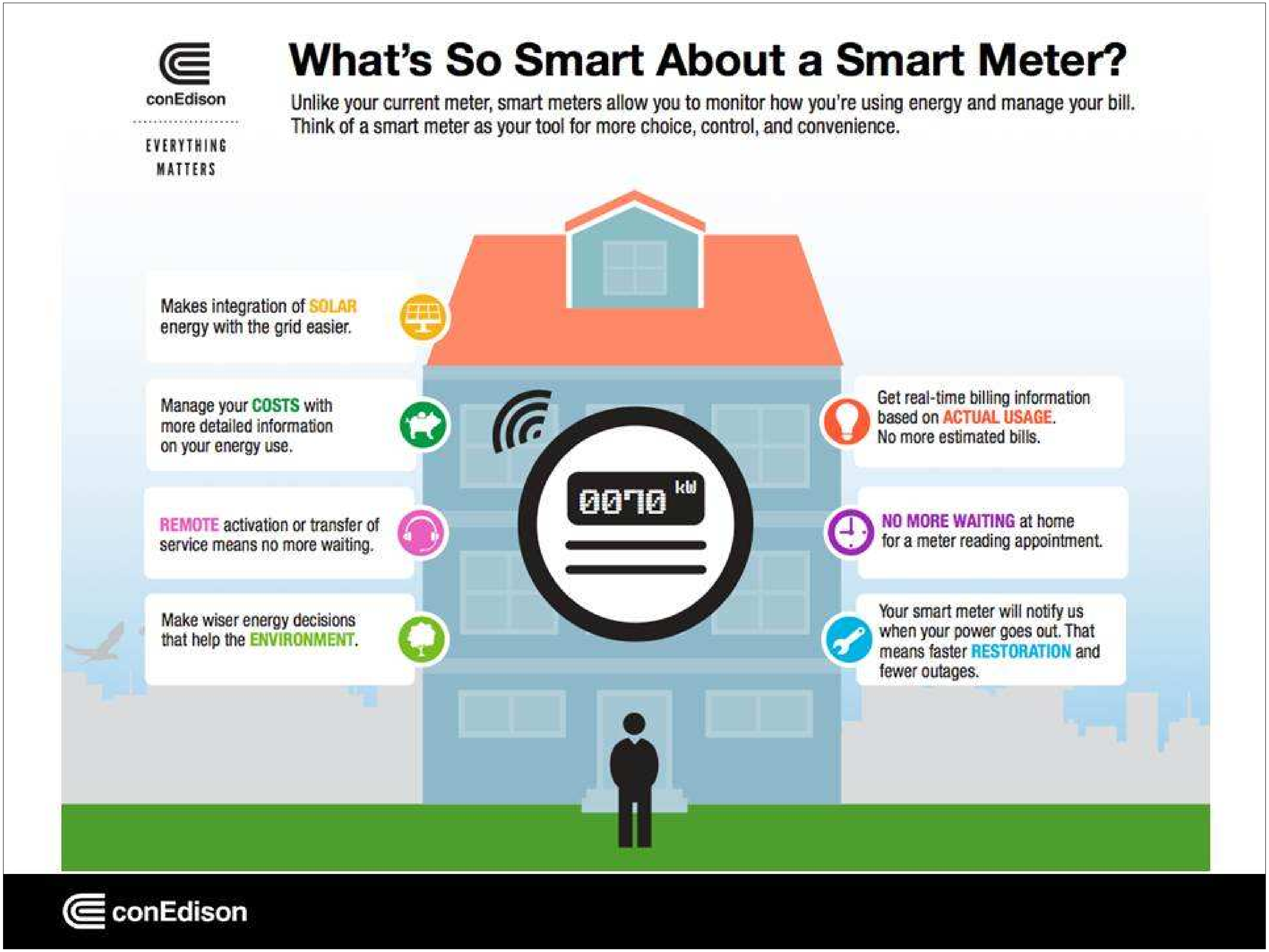
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EVERYTHING MATTERS
What's So Smart About a Smart Meter?
Unlike your current meter, smart meters allow you to monitor how you're using energy and manage your bill. Think of a smart meter as your tool for more choice, control, and convenience.
Makes integration of SOLAR energy with the grid easier.
Manage your COSTS with more detailed information on your energy use.
REMOTE activation or transfer of service means no more waiting.
Make wiser energy decisions that help the ENVIRONMENT.
0070 kW
Get real-time billing information based on ACTUAL USAGE. No more estimated bills.
NO MORE WAITING at home for a meter reading appointment.
Your smart meter will notify us when your power goes out. That means faster RESTORATION and fewer outages.
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AMI Customer Portal

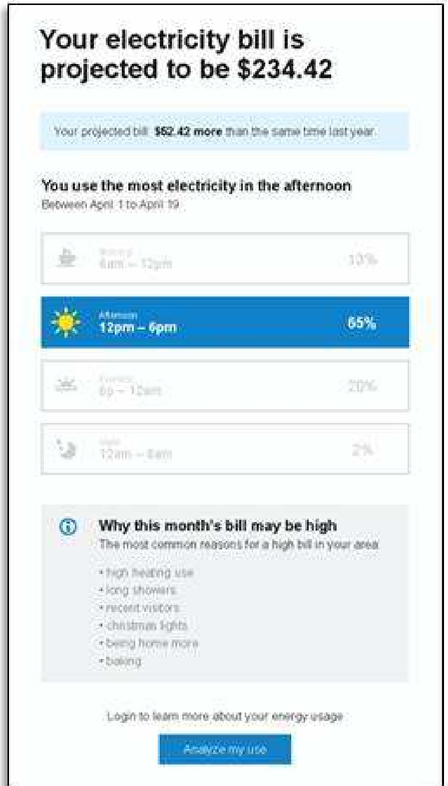
- Portal will provide AMI meter data to all customers
  - Download data in various formats (excel, csv, green button)
- Use customer analytics to turn AMI usage data into insights and customer action
- Customer Engagement through proactive messaging and alerts

Hourly data presentment
Alerts
Bill compare
Rates calculator
Personalized tips
Load disaggregation
Account settings
Bill forecast

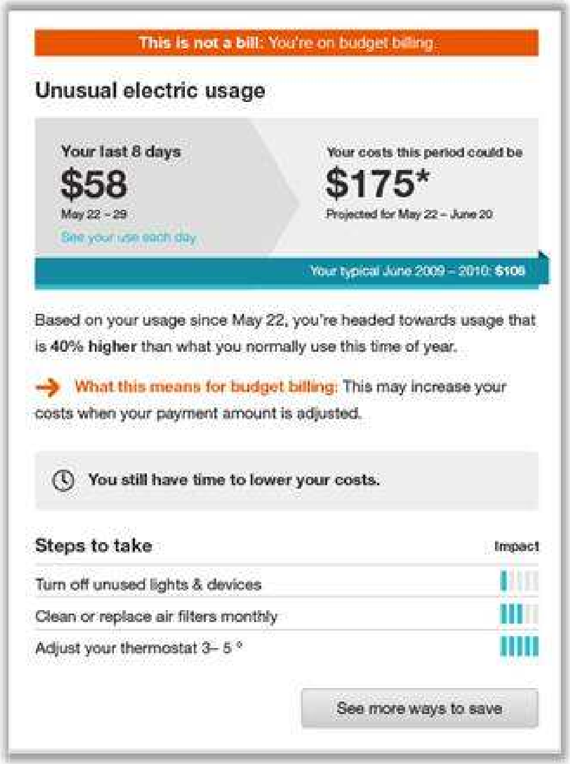
AMI Meter Data → AMI Meter Data Portal → Customer Insights → Customer Action

AMI Customer Portal
Proactive Messaging and Alerts

Projected Bill



Unusual Usage



Weekly Use Summary

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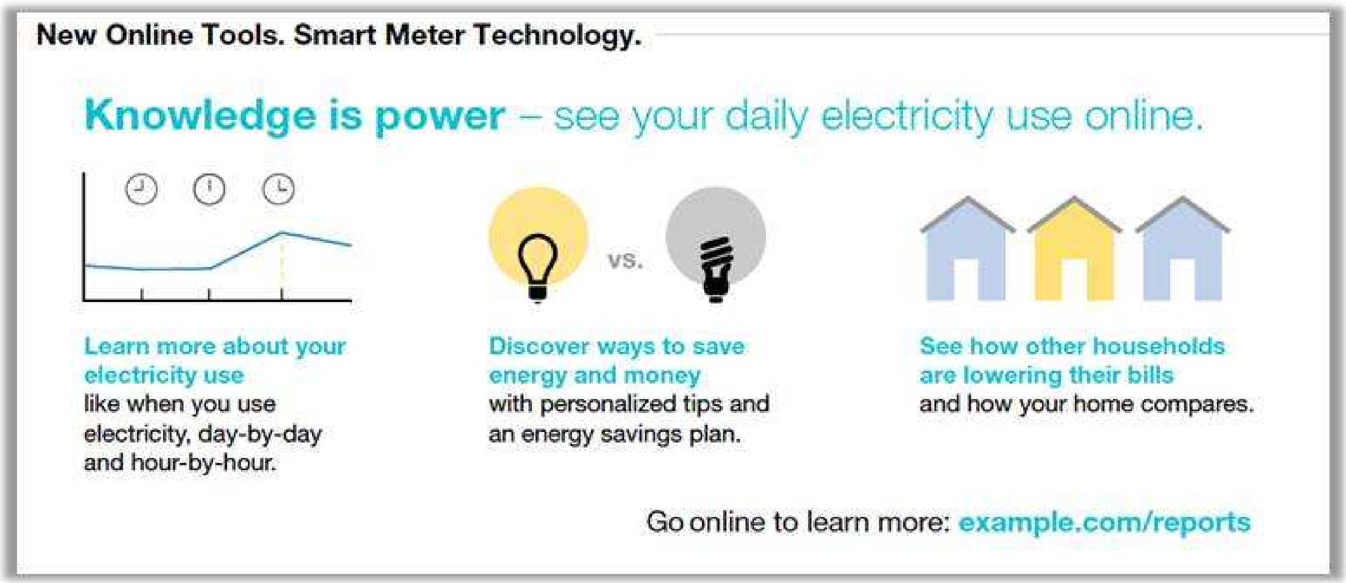
AMI Customer Portal
Proactive Messaging and Alerts

- Increase awareness when meter is installed and tools are available



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AMI Customer Portal
Implementation Plan and Timeline

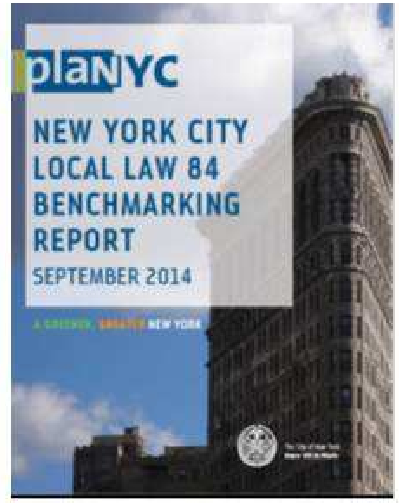
- Address needs of different customer segments
- Optimize for viewing on all devices (Mobile, tablet)
- Align with Digital Customer Experience (web and mobile re-design) and REV Demonstration Projects
- Integration of the AMI meter portal with the coned.com MY ACCOUNT portal
- CSR access to ensure multi-channel assistance
- Customer centric approach during development
  - Workshops, focus groups

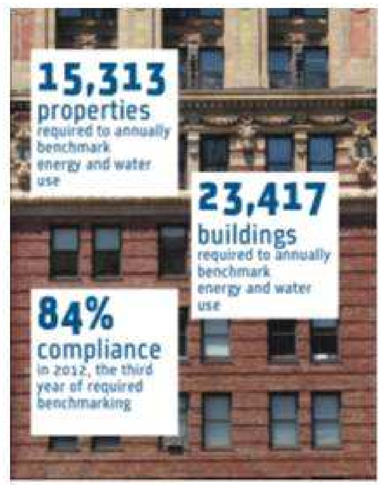
AMI Customer Portal
Data Access and Exchange

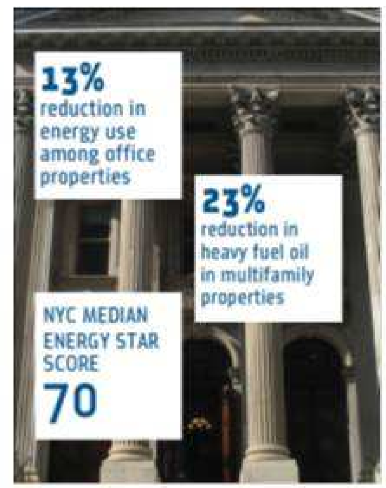
- All customers
  - Existing capability to download via Green Button
- Third Party access to data
  - Evaluating Green Button Connect standard
    - Customer control of sharing of data with third parties
    - Registration of Third Parties to receive automated access to data
  - Benchmarking with PG&E, ComEd and SCE
  - Implementation plan and funding to be considered in REV Track 2

Local Law 84

- Con Edison will work with customers to simplify data aggregation and reporting process
- Researching options – intention to improve process through AMI Portal







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Project Status Update

AMI Plan Overview

- Full scale AMI implementation
  - 4.7 million meters: 3.5 million electric, 1.2 million gas
  - Estimated cost of project - $1.35 billion
- Project phases:

2015
Implementation Planning Effort

- Develop business case
- RFPs & vendor selection
- Implementation/integration planning

2016
Communications and IT Work

- IT platform implementation
- Communication system design and planning

2017 – 2021
Implementation

- Rollout of AMI communication system and smart meters

Project Update – Technology Evaluation

Meters / AMI communication system	• Technical evaluation completed - Negotiating terms
Meter Asset Management System (MAMS)	• Technical evaluation completed - Selected vendor
Meter Data Management System (MDMS)	• Technical evaluation in progress
Others	• Meter & Communication install vendors – RFP issued. Bids due - 10/12 • IT system integrator(s) - RFP issued. Bids due – 10/9

AMI Meter and Communication System RFP

Unique opportunity to capitalize on competitive market and advanced network capability

- Evaluated bids from four leading AMI vendors
  - Shortlisted to two vendors
- Significant savings realized vs. original estimates
- Value added additional offerings
  - Integration of sensors
  - Streetlight and smart city application pilots
  - Enhanced outage management capabilities

Meter and Communication System RFP

Real time data presentment

- Supports data requirements of REV market and desires of stakeholders
- Improved outage performance
- Drives customer behavior changes
- Provides additional network infrastructure for:
  - Integration of DER
  - Control of network protector switches
- Modest price differential between real time and next time data availability

AMI Meter & Communication System RFP

Vendors agreed to conform to performance specifications

Distribution Automation

- Network protector control
- Contingency management – control at meter level to mitigate risk of network shutdown

Outage Notification

- >99% notification of outages to outage management system (OMS)
- Identification of nested outages

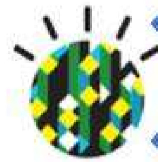
Network Cost Overrun Protection

- Vendor responsible for communication system equipment, installation & future maintenance costs if required equipment quantities are 10% greater than base bid

Leveraging the AMI Network

Customer Convenience

- Eliminates need to provide home access for meter reading or turn-ons/turn-offs



Enabled Electricity Market

- Foundation for time variant pricing plans & demand response growth

Reduced Operating Risk

- Contingency management

Environmental Benefits

- Reduced CO_2 emissions & fuel consumption

Future Operating Benefits

- Advanced sensor technologies

New Business Opportunities

- Pricing plans for usage data
- Smart City applications

Reforming the Energy Vison (REV)

AMI provides foundation for REV

Foundational for Distributed System Platform (DSP)	• Monitoring and verification of DER • Real time metering to support alternative pricing programs • Granular data to optimize planning and market participation
Enables interoperability with other systems	• DER integration and customer sited resource control • Distribution automation integration
Promotes system-wide efficiencies, enhanced visibility and control	• Maximize utilization of distribution system feeders and transformers • Reshapes load curve through responsive device integration • Energy savings and reduced carbon emissions via CVO

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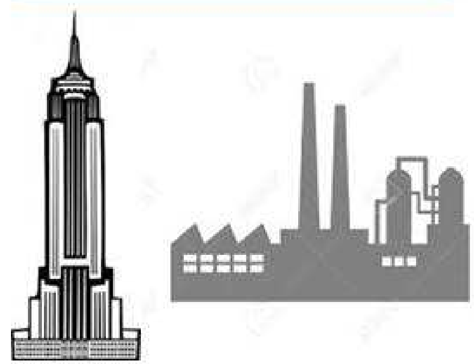
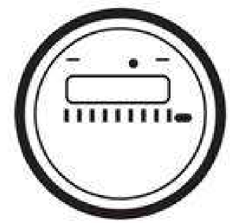
AMI Alternatives Considered

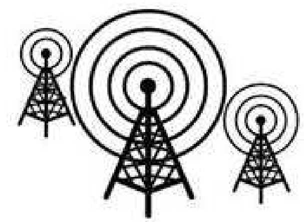
Customer Equipment Solution

Targeted AMI Deployment



Full Scale AMI Deployment



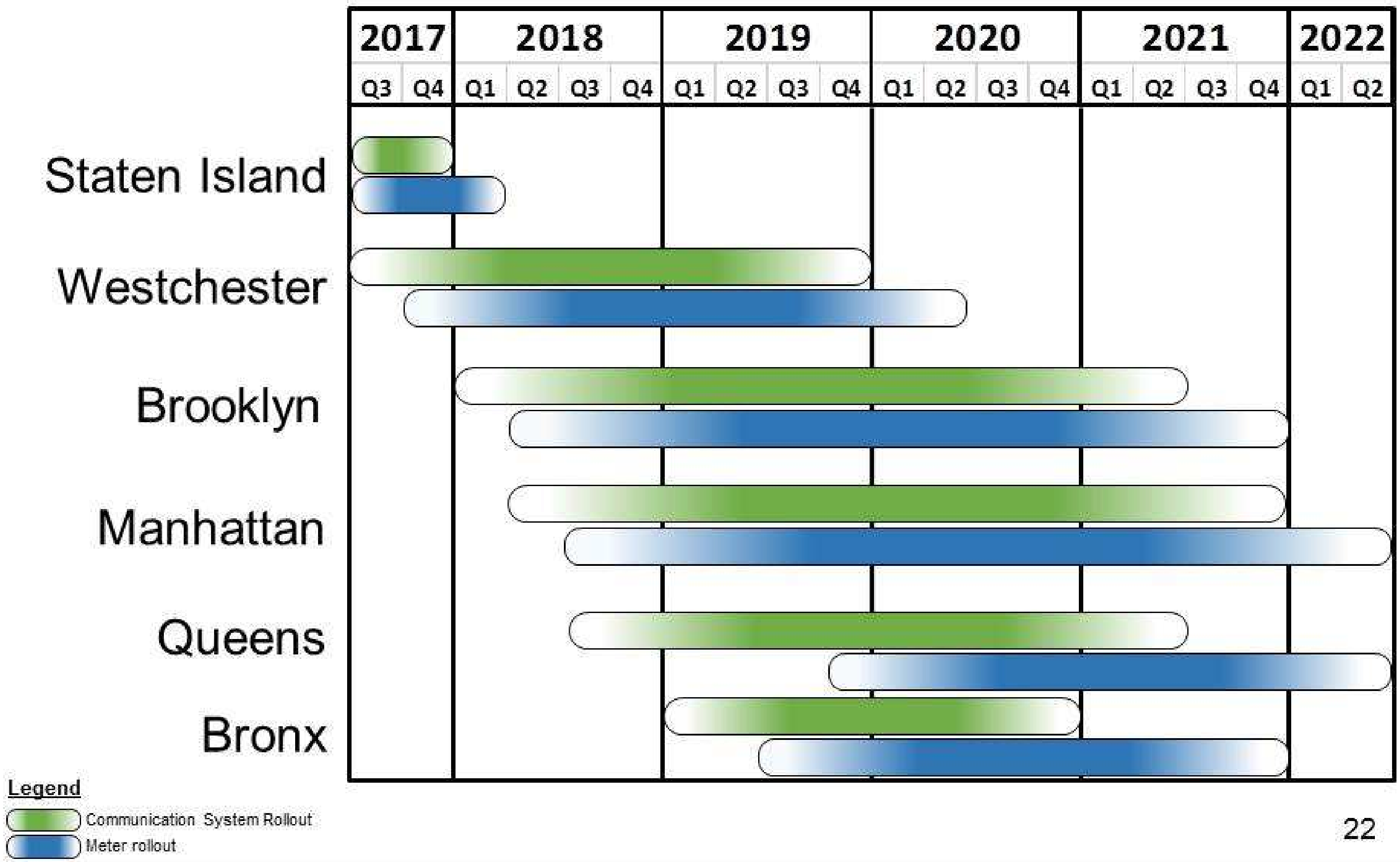


AMI Alternative Comparison

Key Issues	Customer Equipment Solution	Targeted AMI Deployment	Full AMI Deployment
REV Objectives • Promote system-wide efficiency • Enhance system reliability and resiliency • Reduce carbon emissions • Enable Time of Use / Demand rates for all customers • Integration with DER; resource diversity	○	◔	●
Cybersecurity	○	●	●
Smart City Applications • Intelligent sensors • Streetlight controls	○	◑	●
Benefit cost analysis	○	○	●

Implementation Plan

AMI Roll Out Plan



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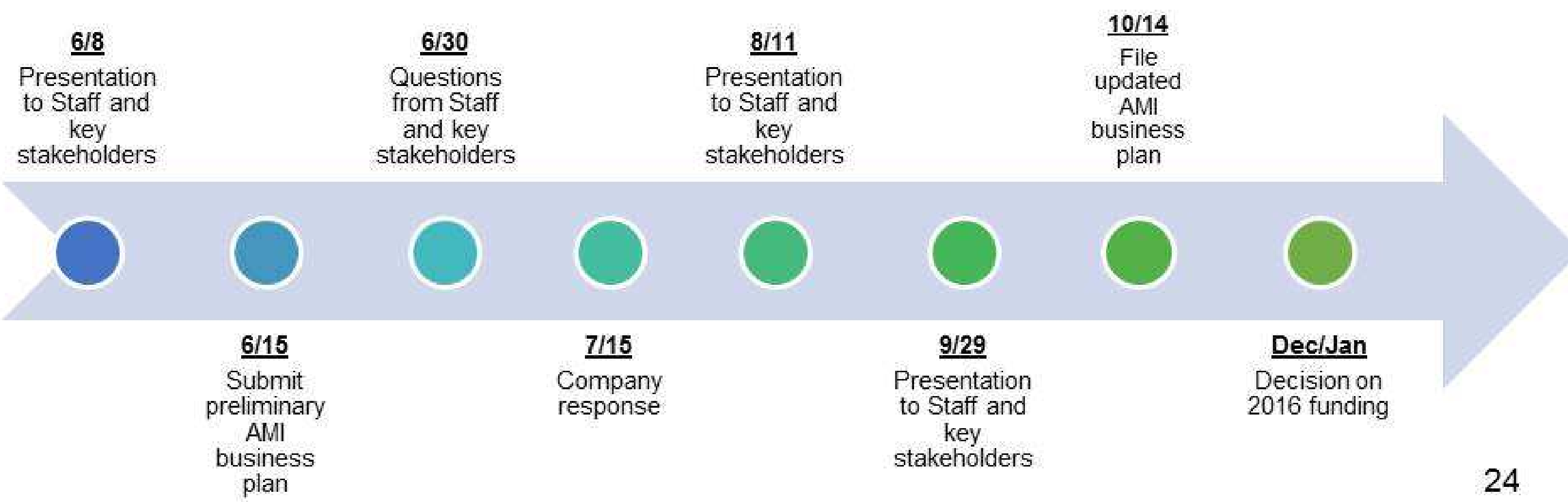
Updated Benefit Cost Analysis

- BCA results being revised with updated cost and benefit information
- 10/14 AMI Business Plan to include updated BCA, reflecting revised inputs:
  - Actual prices from technology RFPs; competitive bids received from AMI vendors
  - Revised benefit realization estimates based on implementation timeline

Regulatory Process
Joint Proposal Commitments

- Agreement with PSC Staff and key stakeholders includes $68 million in 2016
  - Committed to series of updates and reports in 2015
  - Decision on 2016 funding in Dec. 2015 or Jan. 2016
  - Plan to file for remainder of project in Jan. 2016



Next Steps

- Submit AMI Business Plan – 10/14
- Submit revised Business Plan with updated BCA with services vendor costs – 11/15
- File for remainder of AMI project in January 2016