

ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL

ELECTRIC

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1 **I. Panel Member Identification and Background**

2
3 Q. Would the members of the Panel please state their names and
4 business addresses?

5 A. John F. Miksad, Timothy Cawley, Robert Schimmenti, and
6 Robert Sanchez. The business address for Mr. Miksad, Mr.
7 Cawley, Mr. Schimmenti and Mr. Sanchez is 4 Irving Place,
8 New York, NY 10003.

9 Q. By whom are you employed, in what capacity, and what are
10 your backgrounds and qualifications?

11 A. (MIKSAD) We are employed by Consolidated Edison Company of
12 New York, Inc. ("Con Edison" or the "Company"). I am
13 Senior Vice President, Electric Operations. I have been
14 employed by Con Edison since 1981. I have overall
15 responsibility for Con Edison's Electric Distribution
16 Operations and Engineering and Planning. From 1981 to the
17 present, I held positions of increasing responsibility
18 within the Company. During the past 31 years, I have held
19 operating positions in System and Transmission Operations
20 and Electric Operations. My operating experience is as
21 follows:

22 * Senior System Operator, System and Transmission
23 Operations

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* Department Manager of Queens Distribution Services

* Department Manager of the Brooklyn/Queens Control Center

* Chief Distribution Engineer

* Vice President, Manhattan Electric Operations

In September 2005, I was elected to my current position of Senior Vice President.

I earned a bachelor's of engineering degree in electric engineering from Manhattan College in 1981. I am a licensed Professional Engineer in the State of New York.

(Sanchez) I am Vice President of System & Transmission Operations. I have overall responsibility for the development of long term plans for the electric bulk transmission system, the installation and maintenance of the Company's transmission system, as well as, the safe, reliable and economic operation of the electric transmission, distribution and steam system. I have been employed by Con Edison since 1990. From 1990 to present, I have held positions of increasing responsibility in a wide variety of technical and operating positions, including Area Manager, Substation Operations - Manhattan, Senior System Operator - System & Transmission Operations, Chief Engineer - Central Engineering, General Manager - System

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1 Operations. In May 2011, I was elected to my current
2 position as Vice President of System & Transmission
3 Operations.

4 I earned an MBA from Pace University in 2004 and a
5 bachelor's of engineering degree in electrical engineering
6 from the University of Miami in 1988. I was certified by
7 the North American Electric Reliability Corporation (NERC)
8 as a System Operator in 2006 and have completed the Siemens
9 PTI (Power Technology International) Transmission
10 Engineering courses.

11
12 (SCHIMMENTI) I am Vice President, Engineering and Planning,
13 Electric Operations. I have been employed by Con Edison for
14 25 years. I have overall responsibility for Con Edison's
15 Distribution Engineering, Energy Services, Energy
16 Efficiency Programs and Regional Engineering (which was
17 recently centralized under me and will be discussed more in
18 my testimony). I have held various positions including
19 Chief Engineer of Engineering and Planning, General Manager
20 of Electric Construction and General Manager of Substation
21 Operations. In April 2010, I was elected to my current
22 position.

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I earned a bachelor's of engineering degree in electrical engineering from Hofstra University and a master's of science in management technology from Polytechnic University. I have also completed the Transmission Systems program from Siemens PTI (Power Technology International).

(CAWLEY) I am Senior Vice President of Central Operations. I have overall responsibility for the Company's area and transmission substations and our overhead and underground transmission system, our electric and steam production plants, our steam distribution system, and our Central Engineering organization. I have been employed by Con Edison since 1987. From 1987 to present, I have held positions of increasing responsibility in a wide variety of technical and operating positions, including:

- * Electric Control Center Shift Supervisor
- * Environmental Manager
- * Operations Auditing Section Manager
- * Director of Gas Operations at Orange and Rockland Utilities
- * General Manager of Transmission Operations
- * Vice President of Westchester/Bronx Electric Operations
- * Vice President of Substation Operations

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1 In December 2012, I was elected to my current position of
2 Senior Vice President.

3
4 I earned a bachelor's of engineering degree in electrical
5 engineering from Union College and master's degree in
6 business administration from New York University. I have
7 also completed both the Distribution and Transmission
8 Systems programs from Siemens PTI (Power Technology
9 International).

10 Q. Would you briefly explain the purpose of the Panel's
11 testimony?

12 A. The Panel will discuss the importance of, and overall need
13 for, Transmission and Distribution ("T&D") infrastructure
14 investment; how Con Edison's 20-year Electric Long Range
15 Plan supports and guides implementation of Con Edison's
16 mission and strategy; measures we are taking to mitigate
17 damage from future storms; our efforts to maintain
18 reliability while reducing risk and mitigating rates; the
19 details of our Capital infrastructure investment
20 requirements and changes in our O&M requirements.

21 Q. How is your testimony organized?

22 A. Section II of our testimony provides an overview of the
23 Company's electric system. In Section III, we discuss the

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Company's plans for storm hardening the electric system in the aftermath of our experience with Superstorm Sandy. In Section IV we discuss the Company's strategy for limiting capital investments. There, we will discuss the Company's overall mission and strategy and Con Edison's Electric Long Range Plan. Since our last rate case, Con Edison has developed and shared with our stakeholders an Electric Long Range Plan that describes not only our need for infrastructure but also our plans to optimize where and how we invest in the system. We will then discuss our capital optimization model and our risk reduction strategy that enable us to target our capital and O&M dollars as cost-effectively as possible to maintain safety and reliability of our system. In Section V of our testimony, we will discuss cost savings initiatives that have reduced the Company's capital and O&M costs. In Sections VI through XIV, we will discuss the Company's projected capital expenditure requirements and its changed O&M requirements. The remaining sections of our testimony – Sections XV through XXII – will discuss discrete issues.

II. Con Edison's Electric System

A. Importance of Electric Infrastructure to Service Area

Q. Please describe the importance of the electric infrastructure to the Company's service territory.

A. Con Edison is proud of its integral role in the history, growth and development of our service territory. Con Edison distributes electricity to more than 3.3 million customers in New York City and Westchester County, with a population of over nine million people. The City of New York is the most populous city in the United States. It is a leading global city, with influence over worldwide commerce, finance, culture and entertainment. The City is also an important center for international affairs, hosting the United Nations headquarters.

Because electric service reliability is critical for both the economic growth of the region and the health and well being of our customers, it is imperative that we deliver electricity continuously, in a safe and reliable manner. Electricity sustains healthcare, food storage and preservation, water delivery and purification, wastewater, communications, transportation, commerce, entertainment and the conveniences of everyday life. Loss of electricity is

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1 a particular concern for New York City with its significant
2 concentration of high-rise buildings, extensive underground
3 subway and rail transportation systems, and major health
4 care facilities. Reliability and avoidance of major events
5 are keys to the safety and economic health of our service
6 territory. Service problems can have a dramatic impact on
7 residents and businesses. Reliable energy requires ongoing
8 investment in the energy-delivery infrastructure as the
9 essential platform for New York's economic vitality and
10 growth. We pride ourselves on excellence - being the most
11 reliable utility in the nation.

12 Customer demand continues to grow and we hit a system peak
13 on July 22, 2011 of 13,189 MW. Fortunately, we were able
14 to call on (and receive) over 400 MWs of load reduction
15 from the various demand response programs available to us.
16 Otherwise this peak would have been significantly higher.
17 We are forecasting 1.3% growth per year over the next five
18 years, even taking into account our various energy
19 efficiency and targeted Demand Side Management ("DSM")
20 programs that we feel have been very successful.

B. Description of Transmission and Distribution Systems

Q. Briefly describe Con Edison's electric energy-delivery systems.

A. Con Edison's electric service territory covers 604 square miles and is comprised of the five boroughs of the City of New York, with the exception of the fifth ward (Rockaway Peninsula) in Queens, and approximately the southern two-thirds of Westchester County. Our T&D underground system Company is the largest in the United States. The electric system is comprised of approximately 94,000 miles of underground transmission and distribution lines and over 36,000 miles of overhead transmission and distribution lines. Con Edison's service territory, while relatively small geographically, represents approximately 40 percent of New York State's peak electricity demand. Our electric energy-delivery systems are classified into three major categories: the transmission system; transmission and area substations; and the distribution system.

Transmission System: The transmission system includes both underground and overhead infrastructure. Con Edison's underground transmission system is the largest underground transmission system in the United States. We have the

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1 largest underground, pipe-type transmission system in the
2 world, delivering electric energy at 69kv, 138kV and 345kV
3 from generating sources to Company substations
4 strategically located throughout our service territory.
5 Con Edison's underground transmission system is mainly
6 comprised of underground pipe-type cables. This type of
7 cable system, which comprises 85 percent of our underground
8 transmission system, is basically composed of a steel pipe
9 that houses three paper-insulated cables and is filled and
10 pressurized with 8.7 million gallons of a dielectric fluid.
11 Over 200 facilities, located throughout the system,
12 pressurize, circulate and cool the dielectric fluid. The
13 dielectric fluid provides insulation as well as cooling for
14 the cables. The first pipe-type underground transmission
15 feeder was installed in 1947. The average age of our pipe-
16 type underground system is about 42 years.

17 In addition to pipe-type cable, Con Edison's underground
18 transmission system includes other types of cable, such as
19 self-contained, fluid-filled, and solid dielectric. These
20 cables represent the remaining 15 percent of the total
21 length of the underground transmission system.

22 The overhead transmission system, located in Dutchess,

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Putnam, Westchester, and Richmond counties, consists of 1,212 towers which support 356 circuit miles. This infrastructure is situated along 113 miles of right-of-way. The Company also owns or jointly owns 393 structures which support 81 circuit miles in Orange and Rockland counties. The transmission system is subject to high daily loading as well as to a physically challenging underground environment. Accordingly, this system must be maintained, restored and programmatically replaced, to provide a safe and reliable system for delivery of electric power to customers.

Transmission and Area Substations: Substations consist of components (circuit breakers, transformers, phase angle regulators, switches, relays systems and communications systems) that are used to transform, sectionalize, control and direct power on the electrical power system. On the Con Edison system, these substations are referred to as Transmission Stations and Area Substations (or Area Stations). Currently, the Con Edison system has 39 transmission stations and 62 area substations.

The transmission stations are operated at 345kV, 138kV, and 69kV, and have an average age of 46 years. Of the 39 transmission stations, Academy, Mott Haven and West 49th

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1 St. are indoor SF6 insulated stations; Dunwoodie is an
2 outdoor SF6 insulated station; and all others are outdoor
3 open air insulated stations. Typically, transmission lines
4 and generating units are interconnected to transmission
5 stations, which step the voltage down by the use of
6 transformers, to deliver electric power to the area
7 substations that are located close to the end-use
8 customers.

9 With the exception of some of the older stations, most
10 of the 62 area stations are indoor facilities, except for
11 their power transformers. Area substations receive power
12 from the transmission stations and further step the voltage
13 down, by the use of transformers, to deliver electric power
14 to the distribution system. The area substations are
15 operated at 33kV, 27kV and 13kV, and have an average age of
16 38 years.

17 Similar to the transmission system, the substations
18 are experiencing increased capacity requirements because of
19 continuing economic growth in our service territory. These
20 facilities must be maintained, restored and
21 programmatically replaced, to provide a safe and reliable
22 system for delivery of electric power to our customers.

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Distribution System: The electric system's 62 area substations, discussed earlier, supply 83 secondary networks and load areas. The electric distribution system includes the largest underground, low-voltage, distributed secondary network system in the world. Our underground distribution system includes approximately: 249,000 manholes and service boxes; 25,000 conduit miles of duct; 95,000 miles of underground cable; and 39,000 underground network transformers that further step the voltage down from 33kV, 27kV or 13kV to 120/208 volts to supply the low-voltage secondary distribution system. The average age of the underground system is as follows: primary cables - 24.4 years; secondary cable - 37.3 years; and transformers - 18.9 years.

Our (non-network) overhead distribution system is comprised of 4kV, 13kV, 27kV and 33kV feeders. It includes 154 4kV, 13kV, and 27kV autoloops; 257 unit substation transformers; approximately 209,000 poles; about 50,000 overhead transformers; and approximately 34,000 miles of overhead wire including primary, secondary and services. The average age of our overhead distribution system is about 40 years.

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Our distribution system operates on various primary voltages: 4kV, 13kV, and 33kV in Staten Island; 4kV and 27kV in Brooklyn and Queens; 4kV and 13kV in the Bronx and Westchester; and 13kV in Manhattan. There are approximately 2,291 primary voltage distribution feeders supplying network and non-network load. Our network system is second-contingency design (i.e., it is designed to sustain the loss of any two feeders in a network under peak load conditions without any feeder or transformer overloads or adverse impact on service to customers), while the non-network system is first contingency design.

Similar to Con Edison's transmission and substations systems, our distribution system is a vital component of our energy delivery system. It must be expanded, maintained and renovated in order to provide safe, reliable electric service to our customers.

III. Plans for Storm Hardening the Electric System

Q. Please describe the impact of Superstorm Sandy on Con Edison's electric system.

A. Superstorm Sandy ("Sandy") was the largest storm ever observed in the Atlantic Ocean and was the most damaging storm to hit Con Edison in its 120 year history. The

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1 storm's diameter extended almost 1,000 miles and produced a
2 storm surge of 14 feet at the Battery in lower Manhattan
3 that was substantially higher than prior reported storm
4 tides by at least three feet. The storm's record storm
5 tide and severe winds produced extensive coastal flooding
6 and unprecedented damage. Approximately 8.5 million
7 customers along the eastern U.S. lost power during Sandy.
8 The storm resulted in approximately 1,115,000 customer
9 outages in Con Edison's electric system.

10 Q. Please discuss Con Edison's initiatives to harden its
11 electric system to mitigate impacts from future storms.

12 A. In the wake of Superstorm Sandy, the Company is planning
13 extensive new initiatives to harden its infrastructure.
14 First, we will discuss system hardening capital programs
15 and projects already in progress or planned prior to
16 Superstorm Sandy. Next, we will discuss additional system
17 hardening capital programs and projects that we plan to
18 implement over the next three years

19 Q. Did the Company undertake hardening initiatives prior to
20 Hurricane Sandy?

21 A. Yes. The reliability portion of the Company's capital
22 program includes initiatives to harden our system against
23 extreme storm and flood events. These initiatives either

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1 make equipment more robust to withstand the effects of wind
2 and water intrusion during storms, or provide for faster
3 restoration to our system equipment in the event that it
4 became unavailable, either due to electrical faults or
5 planned shutdowns.

6 Q. Please generally describe the hardening projects and
7 programs already planned within Central Operations prior to
8 Superstorm Sandy

9 A. Within Central Operations, the Transmission Operations
10 organization and the Substation Operations organization had
11 a number of capital projects and programs already in
12 progress or planned prior to Superstorm Sandy.

13 Transmission Operations had two projects planned – the
14 reconductoring of feeders running between Dunwoodie and
15 Sprain Brook Substations and the replacement of our L-Line
16 Splice and Dead End Assemblies. These projects will
17 strengthen these feeders and make them less prone to
18 failure in high wind events. In addition, Transmission
19 Operations' ongoing Upgrade Overhead 345kV Transmission
20 Structures program provides for upgrades on selected 345 kV
21 steel lattice towers based on engineering analysis. The
22 reinforcement of these towers decreases the potential for
23 tower failure during extreme weather events.

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Substations Operations' projects and programs include the following:

- The East River Automation project, which is already in progress, will move relays from the street level to the second floor and replace copper with fiber making the East River substation more resilient to shutdown due to flooding as well as allowing for faster recovery in the event of a shutdown.
- Our project to reinforce the Feeder Y94 bypass at Buchanan substation will harden the existing wooden bypass on Y94, making this critical infrastructure feeder much less susceptible to failure during wind events.
- The Pumping Plant Improvement Program will relocate and replace control cabinets and other key equipment at dielectric system pumping plants as well as install backup systems like nitrogen pumps.
- The Switchgear Enclosure Program will seal 13kV bus and switchgear to decrease water intrusion during storm events.
- The Area Substation Reliability Program funds the installation of circuit switchers, which hardens the overall subtransmission system. Certain faults will be

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1 isolated to area stations and not trip back to the source
2 station, allowing stations on common feeders to remain in
3 service. Circuit switchers also allow quicker isolation
4 of faults on common feeders, allowing faster restoration
5 of unaffected stations.

- 6 • The Control Cable Upgrade Program replaces the control
7 wire backbone at Hellgate and Astoria West, which are in
8 the flood zone, to make them less susceptible to shutdown
9 during storm events.
- 10 • The High Voltage Breaker Program replaces circuit
11 breakers in flood zone stations and hardens the unit
12 control cabinets and/or control wiring to make this
13 equipment more resilient to flooding events.

14 Q. What is the approximate cost of these Central Operations
15 storm hardening projects and programs?

16 A. We anticipate aggregate spending of approximately \$63.5
17 million towards these efforts during the four-year period
18 from 2013 through 2016. Additional details regarding these
19 programs are provided later in our testimony in our
20 discussion of the Company's reliability programs.

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1 Q. Please describe the distribution system hardening projects
2 and programs that were already underway or planned prior to
3 Superstorm Sandy.

4 A. Prior to Superstorm Sandy, Electric Operations was
5 implementing or had planned the following capital projects
6 that improve distribution system performance when storms
7 occur:

- 8 • Sectionalizing overhead feeders reduces feeder segment
9 size to limit the number of customers interrupted by
10 storm damage and allows restoration of more customers via
11 remote switching.
- 12 • Establishing additional autoloops reduces the number of
13 customers supplied on existing autoloops and consequently
14 reduces the number of customers potentially interrupted
15 by storm damage to a feeder. In addition, installing
16 additional feeders as alternate autoloop ties provides
17 alternate sources to restore storm-damaged autoloops.
- 18 • Upgrading obsolete and aging vacuum recloser switches
19 with newer, more reliable, remotely controlled switches
20 allows faster customer restoration during storms.
- 21 • Upgrading deteriorated primary and secondary wire reduces
22 vulnerability to breakage during storms.

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- 1 • Inspecting and replacing weakened wooden poles and
2 associated hardware reduces vulnerability to breakage
3 during storms.
- 4 • Installing submersible network protectors that are not
5 vulnerable to flooding allows faster restoration of
6 networks that are preemptively shut down to protect them
7 from adverse impacts of flooding during storms.

8 Q. What is the approximate cost of these distribution system
9 storm hardening projects and programs?

10 A. We anticipate expenditures of approximately \$90.5 million
11 for these projects during the four-year period from 2013
12 through 2016. Additional details regarding these programs
13 are provided later in our testimony in our discussion of
14 the Company's reliability programs.

15 Q. Has the Company established any new initiatives since
16 Superstorm Sandy to reduce the impact of future storms?

17 A. Yes. A corporate System Design Task Force was established
18 in December 2012 to develop and recommend both short and
19 long-term storm hardening initiatives and system design
20 changes that would mitigate the impacts of future weather-
21 related events, such as the damage experienced from the

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1 flooding and high winds experienced during Superstorm
2 Sandy.

3 Q. Please describe the efforts and objectives of this task
4 force.

5 A. The task force consists of a cross functional team of
6 Company employees from a variety of technical disciplines.
7 The task force is developing measures to mitigate the
8 effects of flooding and high winds as well as other storm
9 related conditions, such as, ice loading, snow/ice salt
10 spreading, and extreme heat. The task force is charged with
11 developing effective and efficient cost and capability
12 plans for short term solutions (immediate to three years),
13 near term solutions (three to seven years) and long term
14 solutions (over seven years and up to twenty years). The
15 team will develop a prioritized listing of potential design
16 changes, operational strategies, procedural modifications
17 and hardening initiatives to mitigate the impact of severe
18 weather. Their analysis will include potentially impacted
19 Company facilities, such as electric production facilities,
20 transmission substations, area substations, unit
21 substations, the overhead and underground distribution
22 systems, communications systems and customer generation
23 support.

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1 Q. Has the Company made any preliminary decisions regarding
2 projects and/or programs to enhance and/or reinforce its
3 electric system as a result of its experience with
4 Superstorm Sandy?

5 A. Yes. As we will explain, the Company has preliminary plans
6 to invest approximately \$716 million in new electric
7 system, storm hardening initiatives during the four year
8 period of 2013 through 2016. We will also describe
9 additional storm hardening projects and programs still
10 under evaluation.

11 Q. Please describe some of the initiatives to protect against
12 flooding at various Company facilities?

13 A. Power generation facilities, transmission substations, area
14 substations, and unit substations all have similar concerns
15 when it comes to flood water. We have evaluated 14
16 Substations Operations facilities that were most
17 significantly impacted by Hurricane Sandy - the East 13 St.
18 complex (E13th Street substation, East River substation and
19 E15th St PURS), and the Gowanus, Goethals, Fresh Kills,
20 E36th Street, World Trade Center, Seaport, W49th Street,
21 Hellgate, Bruckner, Sherman Creek and Academy substations.
22 We have evaluated six power generation facilities that were
23 operationally impacted by Sandy - East River, East River

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1 South Steam Station, 59th St., 74th St., Ravenswood A House,
2 and 60th St. We plan to evaluate other facilities not
3 directly impacted by Sandy, such as Farragut substation.

4 We determined that the following equipment at
5 substations is most susceptible to flooding: relay houses,
6 control panels, control rooms, diesel generators, AC and DC
7 power supplies, and pumping plants.

8 One method to protect these facilities is elevating
9 equipment such as pumps, relays, control panels, or entire
10 modules such as control rooms and emergency diesel
11 generators, and enhancing the seals around connection and
12 termination points. In parallel with this, non-
13 operationally critical equipment can be preemptively de-
14 energized to protect against control/power supply short
15 circuits due to salt water intrusion that would
16 significantly increase post-storm restoration durations.
17 Another measure, applicable more to generation facilities,
18 is installing flood barriers, watertight doors, sluice
19 gates, and flood pumps to prevent the migration of water
20 into the stations. For unit substations, in addition to
21 the option to raise, relocate, or build barriers, there is
22 a possibility of eliminating facilities by converting the
23 local distribution system to 13kV or 27kV autoloops.

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1 Additionally, to eliminate salt water intrusion-based
2 failures at transmission and area substations, which
3 results in de-energization of non-faulted equipment, we are
4 evaluating more extensive use of fiber optic-based
5 communications and control in order to provide more
6 effective fault protection during flooding. Our recent
7 experience with such technologies in a flooded substation
8 validates this approach.

9 Q. Please describe the Company's plans to reconfigure
10 substation relay protection systems.

11 A. Traditionally, in a substation, relay houses contain relay
12 protection and communications equipment to provide high
13 speed fault clearing for the high voltage equipment. These
14 relays typically operate with current and voltage inputs
15 from the high voltage equipment, such as transformers and
16 breakers. In addition, the relays provide a DC output to
17 operate the circuit breakers that clear faults and to send
18 trip signals to the remote end energy sources (breakers).
19 By design and because of reliability and risk management,
20 there are typically two independent lines of relay
21 protection for major equipment. This leads to extensive
22 copper cable runs to connect both lines of protection for

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1 the various pieces of equipment to the relays in the relay
2 houses.

3 We are evaluating a new method of installing local
4 relay panels in the direct vicinity of the equipment they
5 are protecting. The current and potential transformer
6 wiring would be run locally to the panels with traditional
7 copper cable (very short runs of 50 feet or less as opposed
8 to hundreds of feet to relay houses), and the extensive
9 runs between equipment throughout the yard would be changed
10 to fiber. The control room in the legacy substations
11 currently uses a hard wired mimic board for local control.
12 Using currently available technology, this will be
13 eliminated by using a computer based Human Machine
14 Interface (HMI) connected to a similar state of the art
15 Remote Terminal Unit (RTU) at the substation. This design
16 allows us to place the "control room" at a higher elevation
17 without extensive rewiring and to eliminate the wiring by
18 using the fiber optics and multiplexors. This design could
19 eliminate relay houses in their entirety, thus eliminating
20 the need to raise or relocate them, while meeting all of
21 the reliability, design and best practice standards. In
22 addition, this design is much more reliable and reduces
23 future maintenance costs.

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1 Q. Please discuss flooding and high wind concerns for the
2 overhead transmission system.

3 A. We did not experience any structural and/or electrical
4 failures due to flooding on the overhead transmission
5 system during Superstorm Sandy. However, we experienced
6 insulator failures and transient faults on overhead lines
7 due to high winds and experienced the loss a couple of
8 transmission lines during the course of the storm. In most
9 cases, the transmission line was restored to service by
10 reclosures. The issues with insulators, which have been
11 replaced, are currently being assessed at a laboratory
12 (EPRI - Electric Power Research Institute) to better
13 understand their mode of failure.

14 Q. Please discuss flooding concerns for the distribution
15 system and/or customer facilities.

16 A. Storm surge levels such as those experienced during
17 Superstorm Sandy may cause damage to non-submersible
18 120/208 volt and 460 volt installations. In addition,
19 flooding of customer premises poses a threat to the safety
20 of the public as a result of stray voltage. In order to
21 mitigate and/or eliminate the potential safety hazard and
22 risk of equipment damage to non-submersible equipment, we
23 have identified a number of networks that have vulnerable

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1 non-submersible equipment within the Zone 1 and Zone 2
2 hurricane flood areas. We will address this issue in
3 several ways.

4 First, we are working on developing submersible 460
5 volt equipment. Second, we can install barriers and
6 pumping equipment, or relocate equipment to higher levels
7 within customer buildings. Third, a new 3G distribution
8 effort to design smaller, more modular equipment that can
9 be installed inside buildings may provide greater
10 protection against damage caused by flooding.

11 We can also install remotely operated flood switches
12 on our network feeders to isolate non-submersible
13 facilities during an event, protecting the integrity of the
14 rest of the network and limiting the power outage area to
15 only flood prone parts of the network. And we can
16 reconfigure network boundaries to separate flood prone
17 areas into their own networks, limiting the impact of
18 preemptive network shutdowns.

19 Q. Please elaborate on what you mean by reconfiguring network
20 boundaries.

21 A. The scope of work would entail changing the network
22 boundaries for seven networks to align with the Zone 1 and
23 Zone 2 hurricane flood impact areas. The affected networks

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would be Brighton Beach, Bowling Green, Fulton, Kips Bay, Chelsea, Cooper Square, and Madison Square. Two of these networks would be divided into two smaller networks, one supplying customers located in the potential flood zone and one supplying the rest of the customers. This will allow for specific isolation of the new network, which would impact a smaller geographic area during a preemptive shutdown in storm response activities. For the remainder of the networks mentioned, three phase switches would be added to the feeders to provide the means to isolate affected 460 volt equipment. The scope of work for the network reconfigurations includes, but is not limited to, new primary cable runs, additional manholes, splicing transfers, establishment of new feeders, and substation work to accommodate the new networks.

Q. Please describe some of the initiatives intended to protect the electric transmission system and generation facilities against wind/rain events.

A. Overall, equipment in each substation that is deemed critical to station function will be raised and protected, particularly control room equipment, the dielectric control system, and relay/control panels, and power supplies will be sealed. Fiber optic-based, salt water-resistant

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1 equipment will be used wherever possible. Procedures will
2 be modified for the preemptive shut down of non-
3 operationally critical equipment to avoid electrical
4 failures due to flooding. For power generation facilities,
5 the focus will be on the mitigation of the ingress of water
6 by utilizing and installing physical barriers around the
7 perimeter of the facilities as well as for protection of
8 equipment inside the stations.

9 Q. Please describe some of the initiatives intended to protect
10 the electric distribution system against wind/rain events.

11 A. Wind and rain events typically affect our overhead
12 distribution systems. Tree limbs and uprooted trees can
13 cause circuits to trip and severe damage to wires, poles,
14 transformers, switching equipment, and other
15 infrastructure. Throughout the years, there have been many
16 initiatives to reduce the number and/or duration of
17 customer interruptions from such events.

18 The cross-functional team that has been assembled is
19 looking at enhancing these efforts and is exploring many
20 other measures. For instance, we are looking at tree
21 trimming cycles, impact zones, clearance requirements,
22 ground to sky trimming, condition based trimming,
23 replanting, and programs to address dead or dangerous

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1 trees. We are looking at the possibility of breakaway
2 primary, secondary, and service wires and even breakaway
3 poles. Breakaway components can prevent forces from being
4 transferred from wires, crossarms and attachments to the
5 poles to prevent pole damage. An alternative to breakaway
6 components is stronger poles, more resilient overhead
7 conductor designs, involving shorter segment lengths,
8 limiting the number of circuits per pole line, and aerial
9 use of underground residential distribution (URD) cable
10 which is more resilient and has a lower profile than
11 overhead wire. Switching to polymer insulators on cutouts,
12 switches, and transformer provides more resistance to
13 breaking or shattering. Adding switches provides
14 flexibility to isolate damage areas and restore customers
15 by tying unaffected areas to alternate supplies. We will
16 continue to add automated, remotely controlled switches to
17 our system for this purpose. Additionally, we are
18 considering manual switches that can be operated from
19 ground level to expand the number of operators capable of
20 making such moves. We are considering splitting up some of
21 our larger recloser loops to reduce the number of customers
22 impacted by a single point of damage.

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1 We have initiated a review of a previous
2 undergrounding study that evaluated the cost, benefits and
3 feasibility of undergrounding selected portions of our
4 overhead system. Additionally, we will continue our efforts
5 to benchmark with other utilities to find innovative storm
6 hardening or storm response techniques. Finally, we are
7 reviewing how technology, such as overhead transformer
8 metering, fuse monitoring or targeting smart meter
9 applications, can help us to monitor the impact of a storm
10 and our restoration progress. Since most of the efforts
11 mentioned in this response rely on communication systems,
12 we are looking at those systems to determine which will
13 need to be enhanced.

14 Q. Are there any other initiatives that you would like to
15 discuss?

16 A. Yes, we have work underway in our Energy Efficiency, 3G,
17 and Research and Development groups that will ultimately
18 improve our ability to mitigate the effects of major storm
19 events. We have developed a platform that can communicate
20 with and manage distributed energy storage and generation
21 assets, which can provide localized emergency support to
22 the electric grid. 3G has been conducting international
23 benchmarking and looking at low voltage switches that can

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1 be used to subdivide a network in an emergency. Also, we
2 are working with the Electric Power Research Institute on
3 the "Grid Resiliency Initiative (GRI)" project. This
4 initiative will evaluate aerial structure resiliency,
5 vegetation management, undergrounding, smart grid,
6 practices for storm response, and prioritization of
7 distribution resiliency investments.

8 Q. How are you planning to prioritize these initiatives?

9 A. Our prioritization process seeks to implement solutions
10 based on realizing the greatest benefits, as early as
11 possible, for the costs expended. We envision a mix of
12 solutions across transmission, substation and distribution
13 at varying levels of individual program spend to optimize
14 overall risk reduction. We recognize that early
15 coordination of programs will allow us to benefit from
16 synergies among the various solutions. Our storm hardening
17 prioritization process considers factors such as public
18 safety, population impact, critical infrastructure reliance
19 on the electrical system, the vulnerability of our systems,
20 and the financial expenditures necessary to achieve
21 hardening.

22 Q. Please describe the storm hardening initiatives for the
23 transmission system and substations.

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1 A. Substation Operations will initiate a Storm Hardening
2 Program that consists of improvements to a number of area
3 and transmission substations that are recommended following
4 assessments of the damages and system impacts that were
5 experienced during Superstorm Sandy. The planned work
6 focuses on near term improvements that we intend to make to
7 the stations that were most impacted by Sandy, as well as
8 stations that shut down as a result of the storm and had
9 the greatest impact on our customers. We anticipate
10 additional work under this program in future years as we
11 further evaluate our entire system and potential hardening
12 options.

13 Much of the initial work will be focused on nine
14 facilities:

- 15 • East 13th Street Substation
- 16 • East River Substation
- 17 • East 16th Street PURS Plant
- 18 • Gowanus Substation
- 19 • Goethals Substation
- 20 • Fresh Kills Substation
- 21 • East 36th Street Substation
- 22 • Trade Center Substation
- 23 • Seaport Substation

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1 At some of these locations, such as East River Substation,
2 East 36th Street, Seaport, and Trade Center, we are
3 planning to modify the substations with items such as flood
4 barriers in the transformer vault walls, flood gates, water
5 tight roll up doors, backflow preventers, and moat walls.
6 At other locations, we are focusing on installing perimeter
7 surge barrier walls to protect the entire facility from
8 flood waters and storm surges. At the East 13th Substation
9 and East 16th Street PURS, our focus is on elevating
10 critical equipment. We intend to relocate the control room
11 at each facility to a second story elevation. This will
12 involve substantial wiring upgrades and replacements to
13 migrate all of the control wiring from one site to another.
14 We also intend to raise the control panels in our
15 pumphouses and cooling plants, install flood barriers and
16 doors, and elevate some key pieces of equipment, such as
17 light and power transformers, diesel generators, and
18 critical load boards and switchgear.

19 We also are evaluating immediate hardening measures
20 that would be in place prior to the summer of 2013 or as
21 soon as practicable thereafter at various other facilities.
22 These immediate hardening measures would include items such
23 as sealing and/or waterproofing control cabinets and cable

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1 troughs and installing flood barriers for individual pieces
2 of critical equipment, such as pumphouses and relay houses.

3 We expect the majority of this initial work to be
4 completed in 2014, with some of the larger scale projects,
5 such as the relocation of the East 13th Street control room
6 and the installation of large-scale surge walls, carrying
7 into 2015 and 2016.

8 Q. Do you anticipate the need for any additional work to be
9 done in the area of storm hardening in the future?

10 A. We do. Our ultimate goal is to provide for full storm
11 hardening of each station. This effort will include
12 protecting all stations and critical substation equipment
13 and assets against future storms. We are anticipating the
14 need to harden other stations based on different
15 hurricane/flooding scenarios. We have evaluated some of
16 these stations; some still need to be evaluated; and work
17 scopes will need to be developed for all of them.
18 Accordingly, we anticipate undertaking some level of
19 hardening initiatives similar to the ones mentioned above
20 at the following stations:

- 21 • Sherman Creek
- 22 • Bruckner/Hellgate
- 23 • West 49th Street

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- 1 • Academy
- 2 • Astoria East/Astoria West/North Queens
- 3 • Farragut
- 4 • Rainey
- 5 • Vernon

6 We may also determine that hardening efforts related
7 to wind events are required at additional facilities. We
8 would anticipate that the hardening efforts at these
9 facilities would commence in 2015 and would be completed in
10 2016.

11 Q. What is the projected cost of the transmission and
12 substation work that you currently have planned for the
13 four-year period 2013 through 2016?

14 A. At this time, we estimate that this storm hardening work
15 would cost approximately \$30 million in 2013, \$60 million
16 in 2014, \$70 million in 2015 and \$80 million in 2016.

17 These figures reflect preliminary order of magnitude
18 estimates for our initial designs. As noted above, there
19 is additional design and estimating work to do. We will
20 update these estimates during the course of this
21 proceeding, as appropriate. Further details regarding this
22 work can be found in Exhibit___ (IIP-6), which discusses

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1 the Company's project and programs related to our
2 "Reliability" work category.

3 Q. Please describe the near term storm hardening initiatives
4 for the distribution system.

5 A. The Distribution System Storm Hardening program expands the
6 Company's existing storm hardening efforts, particularly in
7 low-lying and other vulnerable areas. For example,
8 southerly networks in Brooklyn and Queens and Manhattan
9 would be completely submerged by at least several feet of
10 flood water during a Category 1 or 2 storm. Non-
11 submersible equipment in those networks would be damaged.
12 In that event, it could take days or weeks to restore our
13 systems to normal operating conditions.

14 A number of near term distribution system hardening
15 initiatives have been identified thus far to address both
16 flooding and overhead storm impact. The initiatives to
17 address flooding include reconfiguring the boundaries of
18 vulnerable networks, installation of flood isolation
19 switches, and upgrading vulnerable equipment with
20 waterproof designs.

21 Reconfiguration of the boundaries of the Bowling Green
22 and Fulton networks will allow the Company to preemptively
23 de-energize vulnerable areas of the underground system to

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1 maintain public and employee safety and limit flooding
2 damage while avoiding interruptions to customers in non
3 flood zones. Installation of flood isolation switches in
4 these networks would minimize the outage area on feeders
5 and provide a means of remotely de-energizing 265/460 volt
6 transformers before a storm, rendering them inert in the
7 event of flooding.

8 Approximately 400 non-submersible 265/460 volt
9 underground transformer/network protector units will be
10 storm hardened by installing submersible network
11 protectors. Approximately 1,000 non-submersible 120/208V
12 underground transformer/network protector units will be
13 storm hardened by replacing them with new, submersible
14 units.

15 The initiatives to address overhead storms include the
16 upgrade and retrofitting of overhead distribution circuit
17 equipment and the retrofitting as well as the selective
18 undergrounding of existing overhead lines. The upgrade and
19 retrofitting of overhead distribution equipment would
20 reduce damage to distribution circuits and expedite
21 restoration efforts after storm events. This program
22 involves strategic use of aerial cable that is more
23 resilient to tree impact, reduction of the size of circuit

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1 segments, which results in fewer customers being
2 interrupted, and increased use of automation
3 (sectionalizing devices, fuses and reclosers), which will
4 also reduce the number of customers interrupted by events
5 like tree damage and speed restoration after such events.
6 Approximately 50 miles of aerial cable, 300 sectionalizing
7 switches and 4,000 fuses are projected to be installed to
8 upgrade and retrofit the distribution system for storm
9 hardening.

10 Selective undergrounding of portions of overhead
11 infrastructure would provide immunity from overhead storm
12 damage. Undergrounding would be applied to areas with a
13 prior history of significant damage where tree trimming
14 alone has not been sufficient to prevent significant storm
15 damage. We anticipate selectively undergrounding the ten
16 worst performing linear miles of main run overhead system
17 based on analysis of outage data and field surveys of
18 vegetation density.

19 Q. What is the projected cost for this distribution storm
20 hardening work?

21 A. At this time, we estimate that this additional storm
22 hardening work would cost approximately \$40 million in
23 2013, \$85 million in 2014, \$175 million in 2015, and \$176

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1 million in 2016. Further details regarding this work can
2 be found in Exhibit ____ (IIP-6), which discusses the
3 Company's project and programs related to our "Reliability"
4 work category.

5 Q. Does the electric rate request reflect increased spending
6 on storm hardening projects?

7 A. For the work planned for 2013, the Company plans to perform
8 approximately \$28 million of storm hardening work within
9 the capital budget established for Electric T&D for 2013 by
10 reallocating costs across programs. For the balance of the
11 work planned for 2013 (approximately \$42 million) and the
12 work planned for 2014 (approximately \$145 million), the
13 projected expenditures are in addition to the capital
14 expenditures originally forecasted for Electric for 2013
15 and 2014. As discussed by the Company's Accounting Panel,
16 the revenue requirement for the Rate Year reflects
17 incremental spending on storm hardening of approximately
18 \$150 million. However, the \$42 million of 2013 costs for
19 this initiative were not developed in time to be reflected
20 in the revenue requirement and will be reflected in the
21 Company's update in this proceeding.

22 Q. Are there any other storm hardening initiatives you would
23 like to discuss?

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1 A. Yes, in support of customers who may provide their own
2 generation when grid supply is interrupted, we are
3 exploring several options to improve the ability of
4 customers to provide their own emergency back-up
5 generation, stand-alone Central Heat and Plant (CHP),
6 and/or off-grid renewable supply. For example, we are
7 considering a program that would provide funding to improve
8 the reliability and the environmental profile of customer-
9 owned emergency generation while at the same time providing
10 a dispatchable peak shaving resource for Con Edison. Also,
11 we are working with vendors to address any gaps and crew
12 safety concerns that might exist with our emergency
13 generation specifications for connecting residential and
14 non-residential generators. Resolving these would
15 facilitate the re-energization of customers after storms.

16 Q. Are there any other efforts that would support back up
17 supply for customers?

18 A. Storage technologies could help renewables to self-supply
19 while disconnected from the grid.

20 Q. Do the foregoing efforts represent final plans for storm
21 hardening as a result of Sandy?

22 A. No, they do not. As indicated above, evaluation of storm
23 hardening alternatives is an ongoing effort. The projects

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1 and programs identified in this testimony reflect the
2 Company's best thinking as a result of diligent efforts to
3 focus on storm hardening requirements immediately following
4 the storm. Accordingly, these projects and programs will
5 continue to evolve and may be modified, accelerated or
6 deferred and/or replaced by other programs deemed more
7 beneficial to customers and the service territory in
8 general.

9 Q. Does the Company have a proposal for addressing costs and
10 cost recovery of storm hardening projects and programs that
11 cannot be timely considered for inclusion in rates that are
12 established in this rate proceeding?

13 A. Yes. Company witness Muccilo proposes a framework for
14 addressing the recovery of such costs through a surcharge
15 mechanism.

16
17 **IV. Strategy for Limiting Capital Investments**

18 **A. *Company Mission and Strategy***

19 Q. What is the Company's mission?

20 A. Con Edison's mission is to deliver safe and reliable
21 electric service to customers in a cost effective,
22 environmentally responsible, and innovative way. This
23 mission entails building and maintaining the electric

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1 infrastructure necessary for the transmission and
2 distribution of electricity, procuring energy supply, and
3 providing meter reading, billing and other services to our
4 customers.

5 We recognize the need to do all that we can to hold
6 costs down at all times and are working diligently towards
7 this end. We also realize that our customers will not
8 tolerate reductions in service reliability nor will any of
9 our stakeholders wish to bear increased risk as we endeavor
10 to strictly manage our costs. As such, we have implemented
11 a number of initiatives that allow us to best balance these
12 sometimes competing goals.

13 Q. What guides you toward achieving the Company's mission?

14 A. The Corporate Strategy provides direction to the Company.

15 The Corporate Strategy, as it relates to electric
16 Transmission and Distribution operations, focuses on:

- 17 • providing reliable energy services at reasonable costs;
- 18 • maintaining public and employee safety;
- 19 • promoting energy efficiency;
- 20 • developing cost-effective ways of doing business through
- 21 improved process control (like the Work Management System

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1 we are implementing), new technologies and advanced
2 system designs;

- 3 • strengthening the Company's support activities such as
- 4 systems and technologies that can improve and streamline
- 5 operations;
- 6 • promoting responsible stewardship of the environment; and
- 7 • enhancing relationships with customers, regulators and
- 8 members of the communities.

9 Q. How do Con Edison's employees contribute to the Company's
10 success in performing its mission?

11 A. The Company's success in performing its mission and ability
12 to continue improving depends on the skills and dedication
13 of all our employees who carry out the Company's commitment
14 to excellence and fully embrace our processes, which
15 includes planning the work, communicating openly, accepting
16 responsibility and working as a team. To maintain reliable
17 electric service, the Company must continue to attract,
18 retain and develop a talented workforce focused on current,
19 day-to-day operations, and infrastructure reliability
20 needs.

21 Q. How do Con Edison employees contribute to customer service?

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1 A. The Company seeks to develop a proactive, customer-centric
2 culture that will consistently deliver high quality
3 outcomes for our customers. We understand that customers
4 count on us to deliver safe and reliable service while
5 meeting or exceeding their service expectations.

6 We are working to achieve this objective by focusing
7 on training, communications, performance evaluation and
8 customer feedback. We've enhanced our training to
9 underscore the importance of being a customer-focused
10 organization and to provide employees better strategies for
11 handling customer inquiries. We've improved communications
12 of our front-line employees to focus on the importance of
13 expressing care, concern and empathy when speaking with
14 customers. We've developed observation forms which allow
15 employees to share observations and suggest possible
16 process improvements regarding customer service. We've
17 also utilized customer feedback from survey data to improve
18 the way in which we communicate to customers, particularly
19 during electric emergencies.

20 Q. Has the Company's approach to infrastructure investment
21 planning changed since the last rate case filed in May
22 2009?

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1 A. Directionally, it is still the same; the Company has always
2 strived to provide highly reliable service at a reasonable
3 cost to our customers. However, the Liberty Management
4 Audit, along with additional input from our stakeholders,
5 has underscored for us the need to more explicitly link
6 infrastructure investments to long term planning and to
7 performance, risk and customer bill impacts. As a result,
8 Con Edison has developed an Electric Long Range Plan to
9 guide our efforts to maintain safe and reliable service
10 while minimizing risk and the impact of our infrastructure
11 requirements on customer's bills.

12 In addition, we have developed a consistent, capital
13 planning approach across all electric operations
14 organizations. Our long range plan guides the development
15 of our annual budgets and shorter term plans. Annual
16 budgets and shorter term plans must be linked to the long
17 range plan through the development of annual business
18 plans. Starting with our 2011 annual business planning and
19 budget process, these annual business plans were
20 standardized with uniform guidelines and templates.

21 Risk management is integrated into the budget process.
22 Annual business plans require an enterprise risk management
23 update and discussion of resources committed to mitigate

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1 risks, cost of risks, and quantified dollars in projects
2 devoted to specific risks.

3 The Company uses a Capital Optimization process to
4 evaluate projects and programs enterprise wide, and make
5 optimized expenditure decisions across operating units
6 utilizing standardized analytical methods and guidelines.
7 The Capital Optimization process supports the efficient
8 allocation of funds to reduce operating risks and meet
9 strategic objectives. This methodology takes into account
10 the portfolio's cost, benefits, and weighted strategic
11 value allowing for analysis of all projects and programs as
12 an integrated portfolio. We will discuss the Capital
13 Optimization process in more detail later in our testimony.

14
15 ***B. Electric Long Range Plan***

16 Q. Please describe Con Edison's Electric Long Range Plan.

17 A. Our Electric Long Range Plan ("ELRP") is a road map over
18 the next two decades for serving our customers with cost
19 effective, safe, and reliable power. It provides a
20 strategic framework for implementing our plans to manage
21 demand and supply, invest in our infrastructure, provide
22 environmental stewardship, and to serve our customers at a

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1 reasonable cost. The past decade has been a challenging
2 one for the Company. The next 20 years is expected to be
3 even more challenging as it is reasonable to expect that
4 the pace of technological and social change will
5 accelerate. It is clear that reliable and cost-effective
6 electric service will continue to be necessary to fuel
7 economic growth and customer expectations for our
8 performance will only increase.

9 The Company first published its Electric System Long
10 Range Plan in December 2010. The Company updated the Plan
11 in December 2011. This Plan presents our expectation of
12 customer demand on our electric system for the next 20
13 years (2011-2031), and describes the infrastructure that
14 will be required to safely and reliably accommodate
15 customer demand. The Plan estimates the costs of the
16 investments required to accommodate this demand, and the
17 resulting impacts on our customer bills. The Plan commits
18 the Company to working towards minimizing bill impacts to
19 our customers. The Plan also provides the framework for
20 our nearer term one, five, and ten year plans. Many of the
21 strategies and initiatives discussed in the Long Range Plan
22 are an intrinsic part of this filing.

23 Q. Please provide an overview of the ELRP.

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1 A. The ELRP establishes a comprehensive and quantitative
2 approach to infrastructure-investment optimization over a
3 twenty year period. The Plan integrates transmission and
4 distribution system infrastructure planning with non-
5 infrastructure related elements of our business, such as
6 demand side solutions and renewable resources. The Plan
7 includes major investments in our electric system, specific
8 programs to maintain and upgrade it, and various
9 initiatives to manage customer demand for the benefit of
10 customers and the environment.

11 To support the development of the Plan, the Company
12 created a capital investment database and analytical model
13 to evaluate the impact of programs and initiatives.
14 Capital investment projects were evaluated for impacts on
15 performance, risk, and cost characteristics of the electric
16 system. This analysis is consistent with the Company's
17 asset management practices, annual capital expenditure
18 prioritization process, and our focus on enterprise risk
19 management.

20 The Plan provides a framework that links short and
21 long term projects and programs to the Company's goal that
22 our transmission and distribution systems have sufficient
23 capacity to meet customers' peak electricity demand and

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1 that we can procure adequate energy supply to meet at the
2 least possible cost a projected 25% increase in demand over
3 the planning horizon. The Plan establishes the following
4 objectives:

- 5 • Over the next twenty years we will continue to
6 integrate energy efficiency, distributed generation
7 and demand response that reduce system peak to further
8 our goals of deferring new infrastructure investments
9 and providing safe, reliable, and reasonably priced
10 service that is environmentally responsible. We will
11 provide various methods for customers to manage their
12 energy consumption, expenditures, and to make green
13 choices such as using solar energy sources and
14 electric vehicles.
- 15 • To manage our existing infrastructure, and expand it
16 as required, in a cost-effective manner that maintains
17 our reliability objectives, we will implement
18 innovative designs to defer or minimize the investment
19 requirements of new substations, increase asset
20 utilization, and improve the performance of our
21 electric system. We will challenge some of our long-
22 term ways of doing business to maximize the impact of

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our capital investments. The Plan details initiatives that challenge and fundamentally change key aspects of our current design criteria, moving us from a prescriptive and deterministic engineering design basis to one that is driven by a probabilistic approach. Less asset intensive designs will be implemented on a targeted basis as we tailor our engineering and operational approaches to meet the specific needs of the customers we serve. We will increase efforts to improve our asset management practices as we continue to move from time-based asset management to a condition-based approach optimizing what we spend on our asset maintenance, repair, and replacement decisions. We will continue to implement various Smart Grid technologies that provide greater visibility into the status of our system components and enhanced control over the grid. This technology allows us to increase system automation, improve the accuracy of our predictive system models, and direct us to those system components that need the most attention.

- Just as our business drivers are changing, so are our planning, engineering, and job-based processes and

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1 skills. We will support our workforce by introducing
2 new training that increases our capability to meet the
3 needs of a rapidly changing energy economy.

- 4 • A key to our long range planning process is to provide
5 a direct line of sight between our various initiatives
6 and the customer bill. Our delivery charges,
7 representing the cost of transporting energy from the
8 point of supply to the Con Edison system and
9 ultimately to the customer, constitute less than a
10 third of the typical residential bill; the remaining
11 two thirds are attributable to costs of supply and
12 costs to cover taxes and fees imposed by various
13 government agencies and electricity suppliers. To
14 reduce its electricity costs for customers, the
15 Company will promote governmental and policy reforms
16 in the areas of taxes, financing, supply, ratemaking,
17 operations, customer service, and social policy.

18 These initiatives all have the goal of reducing our
19 total costs and ultimately, the customer's bill. The ELRP
20 forecasts that reliability and replacement investments will
21 be \$600 million lower over the twenty years due to
22 aggressive asset management enabled by improved monitoring
23 and control capabilities and that system expansion

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1 investment will be \$3.6 billion lower over the planning
2 period because of savings from the implementation of 3G
3 substation engineering designs. Our next iteration of the
4 ELRP will look to maintain these savings, but we will need
5 to evaluate the impact of the extensive storm hardening
6 initiatives we are undertaking as a result of Hurricane
7 Sandy.

8 In the next twenty years we expect to invest roughly
9 \$26 billion in capital infrastructure in real 2011 dollars,
10 or an average of \$1.3 billion a year. Replacing components
11 of our electric grid, which have a low average cost due to
12 the vintage of equipment, with a much higher replacement
13 cost will necessarily cause the cost of providing service
14 to increase.

15 Projected customer bills over the twenty-year planning
16 period reflect the impact of higher infrastructure
17 replacement costs, higher energy costs, as well as rising
18 service fees and taxes. We are sensitive to the impact of
19 rate increases on our customers, and we will work very hard
20 to keep costs down. Concurrently we also need to address
21 the needs of service reliability, system safety, and
22 regulatory requirements to maintain the critical electric

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1 infrastructure that supports the economic viability and
2 security of New York City and Westchester County.

3 **C. Capital Investment Optimization Process**

4 Q. Please describe the Company's approach to optimizing their
5 capital investment costs.

6 A. Starting in 2009, the Company systematized its focus on
7 identifying transmission and distribution system capital
8 investments that provide the optimal benefit to our
9 customers. In order to effectively compare the wide array
10 of capital work that we do across our systems, we
11 established a consistent, repeatable and quantifiable
12 process for evaluating and ranking the strategic value
13 associated with each proposed capital program or project by
14 organization and across the Company.

15 This Capital Project Optimization process is a senior
16 management led governance structure that aligns capital
17 project investments to the corporate risks, strategy, and
18 long-term goals in order to maximize the strategic value
19 per dollar spent given our regulatory and operational
20 requirements. The process reviews each capital project and
21 program in relation to their impacts on ten specific
22 strategic drivers such as improving public and employee

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1 safety, providing reliable service, and reducing and
2 managing risk.

3 This approach results in the quantification of
4 benefits from targeted investment to capital programs.
5 Supporting cost-benefit relationships provide an effective
6 means of gauging program effectiveness across investments
7 and at varying levels of investment. Calculated benefits
8 of a program's contribution to risk reduction and
9 achievement of strategic objectives are used to prioritize
10 programs and to dictate program investment across programs.
11 This review ultimately generates a portfolio of projects
12 and programs, each of which has a numeric strategic value.
13 Portfolios then go through an iterative process of
14 aggregation and refinement until an "optimized" portfolio
15 is agreed upon with the appropriate governance committee.

16 ***D. Risk Management***

17 Q. Please describe how the Company approaches risk management.

18 A. In order to pursue safe, reliable, cost effective service
19 to our customers, risk management is of paramount
20 importance to the Company. To mitigate risks to the
21 Company and our customers, in 2005, Con Edison established
22 an Enterprise Risk Management ("ERM") program that

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1 “identifies, analyzes, integrates, assesses, manages
2 monitors, mitigates, and communicates the most significant
3 operating and administrative risks across the enterprise.”
4 In response to a Management Audit recommendation in 2009,
5 the Company has expanded the ERM program by developing
6 departmental level risk profiles and new guidance for risk
7 indicators, and by integrating Enterprise Risks further
8 into our planning and budget processes.

9 A comprehensive Departmental Risk Profile Plan has
10 been developed to facilitate the development of risk
11 profiles across all organizations. This new ERM
12 methodology provides a detailed view of departmental risks
13 and prioritizes risks at the department level. Mitigation
14 plans for each risk are prioritized. These action plans
15 are integrated into the annual budgeting process and long-
16 range planning. The Company has also launched new risk
17 management system. This system has improved the
18 quantification of risk assessment and the monitoring of
19 risks and the projects/programs committed to reduce risk.

20 Annual business plans require an enterprise risk
21 management update and discussion of resources committed to
22 mitigate risks, cost of risks, and quantified dollars in
23 projects devoted to specific risks. Each department

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1 reviews the programs and projects it has in place to
2 address its risks and the progress being made toward their
3 mitigation. Risk mitigation is one component which must be
4 considered in the prioritization of funding. For each risk
5 within their responsibility, departments identify the
6 projected expenditures for both O&M and capital programs.
7 In the Capital Optimization process, one of the 10
8 strategic drivers used in evaluating the strategic value of
9 projects and programs is impact in reducing and managing
10 risk.

11 **V. Cost Savings Initiatives**

12 **A. *Cost-Savings Strategy for Planning Infrastructure***
13 ***Investments***
14

15 Q. Have you explored opportunities that would defer the need
16 for infrastructure investment thereby limiting the level of
17 funding requested in this rate filing?

18 A. Yes. Prior to Hurricane Sandy, our projection for the
19 period of 2013 through 2017 held our projected capital
20 spending virtually flat. However, the storm hardening
21 initiatives that we discuss here have significantly
22 increased our overall capital spending request. Although
23 the new storm hardening work has resulted in an overall
24 increased need for capital funding, we have worked

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1 diligently to minimize this increase to the extent
2 practicable.

3 We will discuss six strategies that will mitigate our
4 capital expenditures:

- 5 1. Capital investment reduction initiatives, including
- 6 the Company's 3G System of the Future Initiative,
- 7 2. Asset management initiatives, including Smart Grid
- 8 3. Demand management initiatives,
- 9 4. Substation construction deferrals,
- 10 5. Modification of programs and projects, and
- 11 6. Cost reductions from improved work practices and
- 12 capital investments.

13 We will then discuss the Company's productivity
14 achievements and make a proposal regarding productivity
15 imputation in this case.

16 Q. What is the Company's strategy for planning infrastructure
17 investments?

18 A. Cost considerations are a major part of our capital
19 planning process. We recognize the need to do all that we
20 can to hold costs down at all times and are working
21 diligently towards this end. We also realize that our
22 customers will not tolerate reductions in service
23 reliability nor will any of our stakeholders wish to bear

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1 increased risk as we endeavor to strictly manage our costs.
2 As such, we have implemented a number of initiatives that
3 allow us to best balance these sometimes competing goals.
4 Our strategy is to invest in infrastructure enhancements
5 only when less expensive alternative solutions are not
6 available to sustain existing reliability levels, provide
7 for localized delivery capacity needs, and support employee
8 and public safety. Through the efforts of our planning
9 processes, we have been able to identify various savings
10 opportunities that will help to minimize customer bill
11 impact. We are employing a more integrated approach to
12 overall system investment.

13 Managing system expansion allows for the deferral of
14 capital-intensive infrastructure investments, which result
15 in substantial cost savings to our customers. Major
16 savings come from our efforts in managing system expansion
17 by using tailored and innovative approaches to system
18 design and better managing our existing assets. We have
19 been successful in targeting smaller, incremental capital
20 investments to the system that help us defer larger, more
21 capital intensive upgrades like new substations and
22 transmission lines over the twenty-year planning horizon.

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1 To manage our existing infrastructure, and expand it
2 as required, in a cost-effective manner, the Company is
3 implementing innovative Third Generation ("3G") System of
4 the Future Initiative designs that have challenged our
5 current design criteria, moving us from a prescriptive and
6 deterministic engineering design basis to one that is
7 driven by a probabilistic approach. These designs are a
8 critical component of our infrastructure-planning
9 framework, allowing us to increase asset utilization and
10 reduce our investment requirements. For certain substation
11 investments that are required to meet system demand, Con
12 Edison plans to adopt innovative, engineering-design
13 techniques developed through the 3G initiative, which we
14 will discuss later in our testimony. We expect that these
15 initiatives will increase asset utilization and reduce
16 overall costs by \$3.6 billion over the next 20 years.

17 Improved asset-management practices, realized through
18 enhanced monitoring and control, will allow us to defer
19 additional capital investment of \$600 million. The Company
20 is also enhancing asset management practices to optimize
21 maintenance expenditures, effectively moving from a time-
22 based to a condition-based approach. Additional

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1 opportunities for savings will be continually and
2 aggressively pursued.

3 The Company is actively integrating innovative designs
4 and advanced technologies with targeted demand and supply
5 side management programs, and traditional designs to
6 implement tailored, "best fit" solutions. Various demand
7 and supply management programs will reduce demand on the
8 constrained parts of our system, thus reducing
9 infrastructure expansion and reinforcement expenditures.

10 Q. Please describe the process by which the Company reflects
11 cost savings in its annual budgets.

12 A. Cost savings can be achieved through efficiency gains from
13 productivity, process improvements that result in cost
14 reductions, or an improved planning process that results in
15 cost avoidance or cost deferrals. The Company's budget
16 process identifies and incorporates cost savings in the
17 authorized expenditures established for the programs and
18 projects set in annual budgets and in the forward-looking
19 projected expenditures.

20 Q. What is the flow of the budget process? How does the
21 budget process begin?

22 A. The budgeting process begins with development of the work
23 plan by each organization. The work plan supports the

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1 goals and objectives of the organization. For operating
2 areas, the work plan focuses on work volumes, projects and
3 programs. Work volumes are forecasted by determining
4 requirements to meet major objectives of each department.
5 Additionally, departments factor in efficiency improvements
6 to incorporate new or enhanced technology and work
7 processes improvements.

8 After the work has been identified, resources are
9 allocated and costs are derived at which point the work
10 plan becomes the budget. As needed, the budgeted work plan
11 is assessed for further productivity and cost saving
12 potential. The budget development process is iterative in
13 nature.

14 As part of this planning and budget process, the
15 Company utilizes a capital optimization methodology to help
16 evaluate projects and programs enterprise-wide and make
17 optimized expenditure decisions across operating units
18 utilizing standardized analytical methods and guidelines.
19 This process evaluates projects and programs to establish
20 the most efficient and effective allocations of funds to
21 reduce operating risks and meet strategic objectives.

22 Q. What tools and methods are used to identify potential cost
23 savings as part of the planning and budgeting process?

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1 A. The electric business operating organizations employ
2 analytical tools and enhanced data analyses that help to
3 optimize the work plan. For example, the Electric
4 Operations' (Distribution) planning process measures the
5 cost-benefit relationship of reliability investment
6 programs to optimize the use of capital and the useful
7 lives of assets. These cost-benefit relationships provide
8 an effective means of gauging program effectiveness across
9 varying levels of spending. These relationships can
10 indicate levels of maximum benefit per dollar spent
11 together with levels of spending at which diminishing
12 returns for the investment program begin to appear. Cost-
13 benefit curves measure one or more specific benefit metrics
14 associated with each program and the realizable amount of
15 benefit the Company can achieve for every dollar spent on
16 the program. Electric Distribution load relief (growth)
17 investment programs have been reduced as a result of the
18 application of enhanced data analysis such as power factor
19 analysis and feeder rating evaluations, which help identify
20 extra capacity in the system that defers the need for load
21 relief expenditures.

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1 Q. Once these savings are identified and reflected in the
2 current business plan and budget, are the savings carried
3 into the future business plans and budgets?

4 A. Yes. The reduced funding levels from cost savings
5 incorporated in the current budget would be embedded in our
6 future forecasts and budgets. For example, Electric
7 Distribution focuses network reliability capital
8 expenditures to obtain reliability improvement in the
9 networks with the highest risk. As the number of networks
10 with unacceptable risk levels decrease each year, fewer
11 network require focused reliability expenditures, and as a
12 result, the projected annual budgets for network
13 reliability expenditures show a decline.

14 ***B. 3G System of the Future Initiative***

15 Q. Please discuss the 3G System of the Future Initiative.

16 A. We intend to meet our service reliability objectives in
17 less asset intensive ways through the implementation of
18 innovative 3G designs. The first generation design,
19 implemented during the initial construction of the electric
20 system, was characterized by radial overhead construction.
21 The second generation design moved much of the
22 infrastructure underground and provided for more reliable
23 service through multiple supply paths. Our newest

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1 generation of engineering designs, developed in our 3G
2 System of the Future initiative, leverage asset sharing
3 approaches and are enabled by enhanced system monitoring
4 and advanced underground switching.

5 3G designs are a critical component of our strategy to
6 defer or minimize the investment requirements of new
7 substations, increase asset utilization, reduce cost and
8 improve the performance of our system. To manage our
9 existing infrastructure, and expand it as required, in a
10 cost-effective manner, the Company is implementing
11 innovative 3G engineering designs that have challenged our
12 current design criteria, moving us from a prescriptive and
13 deterministic engineering design basis to one that is
14 driven by a probabilistic approach. These designs are a
15 critical component of our infrastructure-planning
16 framework, allowing us to increase asset utilization and
17 reduce our investment requirements.

18 3G designs have the potential to result in significant
19 savings in capital investment because they provide the
20 ability to increase system capacity incrementally. This
21 allows us to defer large capacity investments by closely
22 matching relatively small increases in system capacity to
23 customers' growing demand for electricity as it occurs.

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1 The 3G designs also increase the utilization of our
2 existing asset base, deferring a portion of the need for
3 new infrastructure investment. We know our customers value
4 high reliability. Our 3G design concepts were created with
5 the goal of maintaining our reliability levels by
6 considering the probabilities of simultaneous system
7 component failures. Our asset-sharing approach achieves
8 comparable reliability to our existing standards at lower
9 cost than traditional infrastructure investments. Spare
10 substation transformers are shared among multiple
11 substations, thereby eliminating the need for separate
12 spare transformers in each substation.

13 3G design is now fully integrated into Con Edison's
14 design process, and we plan to implement several 3G
15 concepts, including the installation of virtual
16 substations, intelligent underground autoloops,
17 establishing sub-networks with underground auto loops, and
18 automatic primary feeder switches. The asset-sharing
19 technology enables automatic transfers of customers between
20 substations to provide interim demand relief and defer the
21 need to construct a new substation.

22 With growing demand in a certain area, asset-sharing
23 approaches would defer, but not eliminate, the need for

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1 infrastructure investment. The virtual substation is an
2 innovative, responsive capacity expansion process that can
3 be used to better match investment with demand. In a
4 virtual substation design, a new substation is constructed
5 with the requisite switchgear and protection equipment but
6 without transformers. It is supplied via connections to
7 nearby substations. The necessary ducting and cables are
8 built with the ability to supply future transformers,
9 however the transformers are not installed until demand
10 growth is sufficient to require them. This approach lowers
11 the overall size and cost of incremental capacity
12 expansion, thereby lowering costs and improving asset
13 utilization. Each of these designs will serve to advance
14 the achievement of our infrastructure investment objectives
15 and will be used to further reduce customer cost increases.

16 As we mentioned previously, system expansion
17 investments are expected to be \$3.6 billion lower over the
18 twenty year planning period because of savings from the
19 implementation of 3G substation designs.

20 **C. Asset Management**

21 Q. Please discuss the Company's Asset Management initiatives.

22 A. The need to maximize utilization and performance of our
23 existing assets and to optimize maintenance expenditures

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1 makes strong and effective asset management essential.
2 Approximately 45% of the total ELRP capital expenditure is
3 allocated to the Company's asset management and equipment
4 replacement. Therefore, developing the optimal approach to
5 management of component maintenance, repair, and
6 replacement decisions is critically important to the
7 Company and its customers. An effective asset management
8 program affects maintenance patterns, repair and
9 replacement decisions, as well as overall electric system
10 planning and design. Greater precision in identification
11 of the right time to add or replace an asset allows the
12 best directed use of capital and operations and maintenance
13 expenditures. In addition, accurate information on
14 operating conditions allows planners and operators to
15 optimize system configurations when evaluating network
16 reinforcements and replacements.

17 The Company's asset management initiative is
18 designed to facilitate the optimization of "maintain-
19 repair-replace" decisions among all asset classes and
20 asset-related programs. Our planned asset management
21 programs and processes consider the performance, cost
22 and risk profiles of components that, collectively,
23 make up our electric transmission and distribution

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1 system. We use various methods and tools to monitor,
2 analyze, assess and control our assets to obtain
3 optimal performance of our electrical components,
4 asset classes and overall system. The information we
5 capture, trend, and analyze allows us to evaluate and
6 compare the performance across various components or
7 asset classes so that we are targeting our programs in
8 the right places and, therefore, optimizing what we
9 spend on our asset maintenance, repair, and
10 replacement decisions.

11 Enhanced monitoring and control will produce long-term
12 improvements in system performance and lower costs. By
13 gathering and analyzing data from in-field sensors, we are
14 better able to understand performance trends on specific
15 asset classes. Increasingly granular asset health and
16 performance information will enable us to optimize future
17 system investment. As we add more advanced monitoring on
18 our components, we will be able to continue to move away
19 from time-based to condition-based maintenance, which
20 drives towards better cost and performance management, and
21 we have and will continue to develop planning tools like
22 enhanced work management systems to help accomplish this.
23 This may allow us to alter maintenance cycles, increase the

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1 life of various components, improve the design of specific
2 assets, and predict and prevent failures. We are actively
3 pursuing a variety of Smart Grid pilot initiatives to
4 improve the monitoring and control of our system.

5 Improved asset-management practices, realized through
6 enhanced monitoring and control, will allow us to defer
7 additional capital investment of \$600 million by
8 identifying optimal maintenance cycles, determining
9 replacement strategies, and analyzing the system
10 performance, cost, and risk trade-offs over the twenty-year
11 planning period of the Electric Long Range Plan.

12 **1. Smart Grid**

13 Q. Please discuss the Company's Smart Grid initiatives.

14 A. The Company is implementing various Smart Grid technologies
15 that will provide greatly enhanced control over the grid
16 and better system performance. Advances in communications,
17 similar to those known as Smart Grid technologies, have and
18 will continue to give us greater visibility into the status
19 of our system components, allowing us to increase system
20 automation, improve the accuracy of our predictive system
21 models, and direct us to those system components that need
22 the most attention, all with the goal of reducing our total
23 costs. The Company expects a wide range of benefits to

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1 accrue from our Smart Grid initiatives, including the proof
2 of concept of new wireless monitoring and control
3 technologies, new data collection opportunities on
4 distributed supply and customer demand patterns, and
5 secondary model validation from the increased demand and
6 power flow data. We anticipate that change in information
7 and telecommunication technologies will continue to help
8 reduce the overall cost and improve the performance of our
9 electric system. Our long term objective is to develop a
10 smarter grid that will capture the full benefits of
11 improved and additional monitoring, modeling, and control.

12 One element of Con Edison's long range plan is to
13 continue seeking to define and develop the next generation
14 electric transmission and delivery system that will meet
15 our customers' needs 20, 30, or even 50 years from now. We
16 have expanded our dedicated project team in exploring
17 world-wide energy delivery challenges while leveraging
18 federal stimulus monies to deploy new technologies today
19 with as much as 50% government cost sharing. In total, Con
20 Edison leveraged approximately \$200 million in government
21 stimulus money to increase network reliability with
22 sectionalizing switches, deploy PTO (pressure, temperature
23 and oil) sensors to the majority of our underground

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transformers, and pilot smart meters that will ultimately help us improve the way we deliver power. Later in our testimony we will discuss the Company's proposal to include costs of Smart Grid projects in rate base.

D. Demand Side Management Initiatives

Q. Please discuss how Demand Side Management initiatives are contributing to capital expenditure mitigation.

A. While significant business and economic development can accelerate demand growth, especially in the short term, we seek to moderate increasing demand for electricity in our service territory over the long term through comprehensive demand side management including energy efficiency and demand response initiatives. This approach, which reduces demand as well as overall energy consumption, may postpone specific infrastructure investment, and reduces CO₂ and other emissions. While difficult to quantify, this strategy may also reduce the wholesale electric energy and capacity market prices.

As a steward for the environment, Con Edison has long championed energy conservation and efficiency programs. Our "Enlightened Energy" program, launched in the late 1980's realized a savings of approximately 740MW. We continue these efforts today with our demand side

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1 management initiatives through our Energy Efficiency
2 Portfolio Standard ("EEPS"), Targeted DSM, and Demand
3 Response ("DR").

4 Q. Please discuss energy savings and the demand reductions
5 achieved through the Company's Energy Efficiency Portfolio.

6 A. **Energy Efficiency Portfolio** - In response to the
7 Commission's June 23, 2008 *Order Establishing Energy*
8 *Efficiency Portfolio Standard and Approving Programs* (Order
9 Establishing EEPS) in Case 07-M-0548, the Company filed a
10 portfolio of energy efficiency programs on August 21, 2008
11 and September 22, 2008. The Company subsequently
12 implemented a variety of energy efficiency programs serving
13 the residential, small business and commercial and
14 industrial sectors which have saved 350 GWh as of August
15 2012. In addition, the EEPS programs have reduced system
16 peak by approximately 50 MWs through the same period.

17 Q. Please discuss energy savings and the demand reductions
18 achieved through the Company's Targeted DSM program.

19 A. **Targeted DSM** - The Company has implemented a Targeted DSM
20 program since 2003, pursuant to various Commission
21 authorizations, and has achieved 108 MW of load reductions
22 and approximately 279 GWh of annual energy savings as of
23 August 2012. On June 1, 2011, in its *Order Adopting with*

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1 *Modifications a New Targeted Demand Side Management Program*
2 *for Consolidated Edison Company of New York, Inc. in Case*
3 09-E-0115, the Commission authorized the Company to
4 contract for up to another 100 MW of Targeted DSM demand
5 reductions over the following four years. The Company will
6 continue its efforts to target DSM across capacity-
7 constrained areas of its electric system - deferring or
8 eliminating the need for new capital expenditures
9 associated with load relief.

10 Q. Please discuss the Targeted DSM Steam Air Conditioning
11 Incentive.

12 A. **Targeted DSM Steam Air Conditioning Incentive** - The Company
13 has created a new Steam Air Conditioning Incentive, as a
14 component of the Targeted DSM program, to mitigate the
15 impact of customer migration from steam to electric air
16 conditioning in electric networks with sub-transmission and
17 area substation load relief needs identified in the 10-year
18 Load Relief Program. The primary objective of the Steam
19 Air Conditioning Incentive is to retain existing steam air
20 conditioning customers or attract new steam air
21 conditioning customers in those networks where avoiding new
22 or reducing existing electric chiller loads will make it
23 possible to defer capital expenditures on new electric

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1 infrastructure. Incentives will be offered in the targeted
2 electric networks to both existing steam air conditioning
3 customers and electric air conditioning customers who
4 switch to steam air conditioning. Additionally, new or
5 major renovation projects that install steam chillers in
6 lieu of electric chillers will also be eligible.

7 **Demand Response(DR)** - On October 23, 2009, the Commission
8 issued its *Order Adopting in Part and Modifying in Part Con*
9 *Edison's Proposed Demand Response Programs*, in Case 09-E-
10 0115, authorizing the Company to implement DR programs.

11 Pursuant to the October 23, 2009 and subsequent DR orders,
12 the Company's DR programs currently have 300 MWs and 26,000
13 customers enrolled (over 200 unique MWs) that were called
14 on when needed this summer. DR programs are an
15 increasingly important component of Con Edison's efforts to
16 cost-effectively reduce peak-load related economic, social
17 and environmental costs. The Company's load forecasts now
18 include the anticipated demand reductions associated with
19 DR programs during peak periods across the Company's
20 electric networks. Program performance, participant
21 diversity risk, likelihood of re-enrollments, growth,
22 allocation uncertainty, etc. are all factors that adjust
23 the DR "baseline" demand reductions established using

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1 actual program enrollments. This allows the Company to
2 incorporate DR resources into its planning and defer system
3 capacity upgrades that would otherwise be required.

4 ***E. Substation Construction Deferrals in Long Term Load***
5 ***Relief Plan***

6 **1. Deferred Substations and Cost Deferral**

7 Q. Please discuss the Company's deferral of Substation
8 Construction Projects as projected in the Company's long-
9 term Load Relief Program

10 A. A substation cannot supply more electricity to its networks
11 or load areas than the capacity of its transformers and/or
12 its supply feeders. When the electric demand from
13 customers in a network or load areas begins to approach the
14 design capacity of the substation supplying that network or
15 load areas, Con Edison follows a least cost evaluation
16 process in order to provide adequate service to its
17 customers. The first step is evaluating the best approach
18 to meet the demand requirements utilizing the least cost
19 option. The best approach at least cost may include one,
20 or a combination of, the following activities: targeting
21 Energy Efficiency Programs and exploring potential Demand
22 Side Response initiatives in the area; maximizing the
23 substation's design capacity by installing additional

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1 equipment, such as transformers, transformer cooling, and
2 static capacitor banks; reducing the size of the
3 distribution network or load area by transferring some of
4 the load to a nearby substation with spare capacity; and as
5 a last resort, building a new substation and transferring a
6 portion of the load to the new substation.

7 The Company has been able to defer a substantial
8 number of substation construction projects as a result of
9 its initiatives to more effectively utilize existing
10 substation capacity through the 3G initiative, demand side
11 management measures, and distribution system load
12 transfers, in addition to a decline in the projected growth
13 of load. Our 2008 – 2017 10-year Area Substation and Sub-
14 transmission Feeder Load Relief Program (Load Relief
15 Program), which was based on our September 2007 load
16 forecast, deferred eight new substations (Gateway Park,
17 Idlewild, Hudson Yards, Nevins Street, Hillside, Westside,
18 Gowanus, and Queens), the installation of two major feeders
19 connecting the Bronx (Mott Haven Substation) to Queens
20 (Queens Substation), and two feeders connecting from Queens
21 to Brooklyn (Gowanus Substation). This resulted in a
22 significant capital investment deferral of about \$1.2
23 billion (substations and transmission combined). Based on

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our 2012-2021 Load Relief Program, these deferrals will extend beyond 2022. Additional new area substations have been identified in forecasts after the 2008-2017 Load Relief Program forecast; however, they have also been deferred beyond 2022. Additional new area substations have been identified in forecasts after the 2008-2017 Load Relief Program forecast; however, they have also been deferred beyond 2022. The Queens switching station, which was originally conceived as a 345kV station has been replaced with a more cost effective option using 138 kV ties to LIPA, Corona and Jamaica.

2. New Load Relief Program Initiatives

Q. In addition to 3G design changes, demand side management measures, and distribution system load transfers, what other initiatives has the Company undertaken to defer substation projects?

A. The 2012-2021 Load Relief Program has incorporated the following three new initiatives that have been effective in deferring substation projects:

- Incorporating distributed generation that meets certain reliability criteria as part of the area station/sub-transmission feeders' capability

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- 1 • Utilizing voltage reduction at certain area stations
- 2 to deload the sub-transmission feeders
- 3 • Power factor engineering analysis

4 These three initiatives, in essence, provide additional
5 capacity that can be used to meet existing and future loads
6 and has allowed the deferral of several projects in the
7 2012-2021 Load Relief Program. The cost of the deferred
8 projects total approximately \$270 million.

9 Q. Please discuss each of these initiatives.

10 A. **Distributed Generation** - We are beginning to incorporate
11 reliable Distributed Generation ("DG") when reviewing load
12 relief requirements for an area substation. Improvements
13 in DG technology coupled with the deployment of
14 sophisticated, multi-megawatt systems by some of our
15 largest customers provides DG customers the opportunity to
16 achieve total energy cost savings and the Company the
17 opportunity to avoid infrastructure investments at the
18 substation level, where the Company determines it can
19 reasonably rely on these units to run and operate reliably
20 during the summer peak, with operating protocols in place
21 to meet load under circumstances where the DG units are out
22 of service on peak summer days. In our 2012-2021 Load

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1 Relief Program, we considered 24MW of DG to offset capital
2 requirements for load relief. The incorporation of CHPs in
3 our program deferred over \$8 million in load relief
4 projects.

5 **Area Station Voltage Reduction:** A planned voltage reduction
6 in area substations lowers the load in those substations.
7 This, in turn, reduces the load experienced by the sub-
8 transmission feeders that supply the area stations, and
9 will allow us to defer planned upgrades to sub-transmission
10 feeders in certain instances. The incorporation of area
11 station voltage reduction to reduce loading on sub-
12 transmission feeders resulted in deferral of over \$1
13 million in load relief work over the period of the 2012-
14 2021 Load Relief Program.

15 **Area Station Power Factor:** As a result of advances in our
16 ability to model and analyze data from our SCADA systems,
17 we are able to analyze and more accurately determine power
18 factors at our area substations. The revised power factors
19 have been reflected in increased substation, sub-
20 transmission and transmission capability in the 2012-2021
21 Load Relief Program. The increased capabilities have
22 allowed the deferral of over \$260 million in several costly

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1 load relief projects during the period of the 2012-2021
2 Load Relief Program.

3 ***F. Modification of Projects or Programs to Mitigate Rates***

4 **1. Projects or Programs Deferred or Reduced in Scope**

5 Q. Can you provide some examples of non-mandatory projects or
6 programs that have been deferred or reduced in scope to
7 mitigate rate impacts on customers?

8 A. Yes. The following projects or programs were either
9 deferred or reduced in scope to mitigate rate impact on
10 customers:

11 **Substation Transformer Replacement Program** – There are
12 approximately 400 power transformers on the system of which
13 approximately 150 are over 40 years old. As these units
14 approach the end of their life cycle, corrective
15 maintenance and the probability of failure increase. Based
16 on the current population of 150 large power transformers
17 that are over 40 years of age, the Company would need to
18 replace 10 transformers per year over a 15 year period to
19 proactively address transformer life cycle aging issues,
20 but it is not cost effective at a cost of approximately
21 \$60-70 million per year. As an alternative approach, the
22 Company has initiated an asset management program, which
23 blends operational needs and effective cost management by

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utilizing diagnostic tools. These tools include dissolved gas-in-oil analysis ("DGOA") to identify those transformers that have the highest risk of failure. This effort has consequently enabled the Company to limit the program to replacement of approximately 2-3 units per year at a cost of \$21.1 million in 2011, \$13.8 million in 2012, and about \$25.5 million annually from 2013 through 2017. This approach mitigates approximately \$35 million per year while maintaining system reliability.

138 and 345kV Breakers - We have worked with EPRI to develop new condition monitoring based replacement and overhaul criteria for high voltage breakers. This has reduced the annual average expected funding requirements for this program from an average of \$14.5 million for the period 2007-2011, to an average of \$9.5 million going forward, for an annual savings of \$5 million.

Paper Insulated Lead Cable (PILC) - Working with PSC staff, the Company has developed a more balanced approach to targeted PILC removal. The new goals of this program, working with other PILC cable removal methods, will now reduce the amount PILC cable to less than 10% of the total population of primary distribution network cable by year-

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1 end 2020. This will lead to a savings of approximately \$6
2 million over the next three years from 2013 to 2015.

3 **Vented Service Box Covers** – The original plan was to
4 complete the program at the end of 2017. With
5 approximately 34% of the system vented, we have performance
6 data that will guide in deploying vented covers in the
7 optimal way that supports public safety. We plan to extend
8 the program to 2025 and continue to evaluate the return on
9 investment and refine the optimal method of deploying
10 covers. By extending the program, the total savings from
11 2013 to 2015 will be approximately \$5 million.

12 **Transformer Purchases** – The purchase of some transformer
13 line items will be deferred due to our using more
14 reconditioned transformers and salvaging more components
15 from our network protectors. The total savings from 2013
16 to 2015 will be approximately \$26 million.

17 **Network Reliability** – As a result of the effectiveness of
18 our reliability program actions including component
19 replacement and sectionalizing switch installations, we
20 anticipate achieving our reliability NRI targets with fewer
21 feeder installations. This program has been modified to
22 establish four to five feeders per year versus five to six

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1 feeders per year. The total savings from 2013 to 2015 are
2 estimated to be \$10 million.

3 **2. Projects or Programs Extended to Mitigate Rate Impacts**

4 Q. Have any Feeder Replacement, Upgrade, and Installation
5 projects been extended to mitigate the rate impacts on
6 customers?

7 A. Yes. A defined process for setting priorities, meeting
8 with supporting organizations and matching field capacity
9 has lead to focusing on projects that are to be designed
10 and constructed with a "just in time" philosophy. This
11 establishes a portfolio of available projects and work
12 tasks that are current and important and diverts resources
13 from less important jobs. Such projects include:

- 14 • Replacement of 69kV feeders on the Queensboro Bridge has
15 been further deferred resulting in a \$27 million
16 deferral.
- 17 • Replacement of feeders 34182/34184 has been further
18 deferred resulting in a \$22 million deferral.
- 19 • Re-cabing of selected sections of Feeder M51 has been
20 deferred indefinitely resulting in a deferral of \$10.4
21 million.

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- Replacement of feeders 18001 & 18002 has been deferred resulting in a \$33.8 million deferral.
- Re-cabling of feeders 99941 & 99942 has been deferred resulting in a \$10 million deferral.

G. Capital and O&M Cost Reductions from Improved Work Practices and Capital Investments

1. Work Management System

Q. What actions has the Company taken to improve its work processes and reduce costs?

A. The Company is using Information Technology to improve operating efficiency. The primary example is the Electric Operations Work Management System deployment, which will be fully implemented in September 2014. In 2009, Con Edison's Electric Operations group assembled a dedicated team to initiate a Phase 0 Assessment for Electric Work Management Business Process and Information Systems. A full time team comprised of key business users in Electric Operations, Information Resources support staff, and consultants, was dedicated to this effort. The team reviewed all work management business processes associated with all work performed by Electric Operations including:

- Emergency repairs

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- 1 • Maintenance and inspection
- 2 • New construction and customer connections
- 3 • System performance/reliability programs

4 The Phase 0 Assessment Team identified opportunities
5 to streamline processes and effect the changes necessary to
6 establish a best-practice work management program and
7 finalized a technology strategy for processing work within
8 Electric Operations. The team also determined that the
9 Company should migrate to a new work management platform
10 based on a leading commercial solution. A detailed
11 business case cost estimate, implementation plan and change
12 management strategy was developed and was authorized by
13 senior management and Board of Trustees.

14 The Work Management project consists of several
15 initiatives; new process implementation, new organizational
16 structure, and deployment of best in class technology with
17 the Logica ARM Suite and other applications. The project
18 will deliver benefits by implementing a standardized
19 process for planning, managing and executing work across
20 Electric Operations resulting in daily job functions being
21 more efficient.

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1 The process and application will allow for field crew
2 scheduling that will improve crew productivity and maximize
3 crew utilization. The deployment of a new organization
4 dedicated to forecasting, planning and scheduling coupled
5 with the use of the new applications will allow field
6 supervision to spend less time planning and scheduling work
7 and more time with field crews leading to higher quality of
8 work, increased safety awareness and increased performance.
9 Managing job prerequisites in a more efficient manner will
10 match City and State permits more closely to work schedules
11 as well as better coordinate the state of projects with the
12 availability of capacity, materials and equipment. The use
13 of the real time mobile application will eliminate much of
14 the back office administrative work that is done today to
15 manage, schedule, and dispatch work to crews as well as
16 reporting back on progress of work on various tasks. The
17 combining of the Regional Engineering departments into one
18 organization will promote standardized practices and design
19 as well as the ability to review work across the regions to
20 focus on engineering the work with the highest priority.
21 The new Work Component – Compatible Unit concept will
22 contain material information thus allowing major material
23 items to be automatically requested when a project task is

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1 scheduled. This will reduce the administrative requirement
2 to order major material in a separate application. The
3 adoption of best practice work management processes and
4 information systems will facilitate improved cost tracking,
5 work scheduling, status reporting and productivity
6 analysis.

7 The deployment of new forecasting, planning and
8 scheduling processes as well as the deployment of a new
9 organization to manage these processes was completed in the
10 fourth quarter of 2011. The centralized Engineering
11 organization was deployed in the second quarter of 2012.
12 Reflecting some timing adjustments due to Superstorm Sandy
13 effects, the entire work management solution is expected to
14 be fully deployed by September 2014, and the Company
15 expects to realize full annualized savings in 2015.

16 Some of the key benefits from deploying the new Work
17 Management system and processes include:

- 18 • 70 minutes of additional productivity per day for
19 field crews through more efficient scheduling,
20 improved prerequisite management, and increasing
21 available field time for supervision.

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- A 65% productivity improvement for clerical staff through administrative efficiency gained from reduced work package preparation, reduced data entry, and reduced need for error correction.
- A 15% productivity improvement for engineering through effective application of compatible units, design standardization, organizational restructuring and improved time allocation of personnel.

In addition, a consolidated work management system platform will provide:

- A single repository for all planned and emergent work within Electric Operations so users no longer need to access multiple systems to process work
- An interface that provides detailed information about electric distribution assets for which work is being performed
- A comprehensive facility that helps manage all maintenance and inspection programs
- A mechanism to match project work requirements and tasks to worker skills and other resources such as vehicles and other equipment

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- Trending and analysis of workforce and equipment performance
- A summary of all associated costs by work activity or project
- Interfaces to Finance, Supply Chain and HR systems that reduce clerical input and further streamlines processes
- A resource scheduling and planning assistant
- Integration with mobile technologies allowing the transmission of data to/from the field

Upon full implementation, the Company expects to realize annual savings of \$45 million dollars, split between capital and O&M.

2. Other Work Processes and Capital Investments

Q. How else has the Company managed capital investments to reduce costs?

A. The Company manages its capital projects to keep costs as low as possible, to reduce the risk of cost overruns and to discover as soon as possible any departures from project estimates with respect to schedule or cost.

An order-of-magnitude estimate, or feasibility estimate, is used for proposed project evaluation, for

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1 comparison of alternate schemes. The Company uses a
2 Capital Optimization process to help evaluate projects and
3 make optimized expenditure decisions across operating units
4 utilizing standardized analytical methods and guidelines.
5 This methodology takes into account the portfolio's cost,
6 benefits, and weighted strategic value allowing for
7 analysis of all projects and programs as an integrated
8 portfolio. Following this project prioritization and
9 approval of the budget, a detailed appropriation estimate
10 is prepared based on a detailed engineering scope of work,
11 which is approved by the operating organization,
12 construction, and engineering.

13 For large capital projects, such as the expansion of a
14 substation, operating organizations assign a project
15 manager to oversee all phases of a project. The project
16 manager facilitates formation of a multi-discipline core
17 project team that includes a project engineer and a
18 construction manager. The engineering team is led by a
19 project engineer and includes representation from
20 appropriate technical disciplines. The engineering process
21 resolves site selection, demolition, site remediation,
22 equipment specification, environmental and safety hazards,

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1 above and below-grade design for construction, permit
2 requirements, and testing procedure issues.

3 The project manager develops a project schedule and
4 estimate and obtains appropriate concurrence and project
5 appropriation approval. In addition, the project manager
6 establishes work orders for identified work groups,
7 approves, issues and maintains a current detailed project
8 schedule, and initiates and maintains the current working
9 estimate for the duration of the project. The project
10 manager coordinates in-service requirements and work
11 sequence for physical electrical/mechanical tie-in to the
12 existing systems, plant modifications, system outages, and
13 system restoration. The project manager facilitates
14 assignment of a construction manager to review design-
15 constructability and manage the construction phase of the
16 project.

17 The project manager and construction manager will make
18 decisions on the utilization of Company labor or contract
19 labor during the performance of a project using a
20 standardized decision-making process established in the
21 Company's guidance memorandum titled "Evaluation of the Use
22 of Contractors to Perform Work for the Company."

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1 For work that will be done via contractor forces, the
2 construction manager prepares and issues purchase
3 requisitions, identifies any special conditions for
4 bidding, coordinates with the Purchasing Department
5 representatives on the type of contract to be obtained and
6 selection of bidders for the work required. The project
7 and construction manager integrate individual contractor
8 schedules into the overall project schedule.

9 For smaller scale capital and O&M programs,
10 engineering discipline engineers assume responsibility for
11 the project engineering functions. Experienced operating
12 organization personnel, including planners, generally act
13 as project managers and operating area managers fill the
14 construction manager role. If contractor labor is
15 required, construction will also assign a construction
16 manager to provide oversight for the contract management.
17 Construction management oversees the construction
18 contractors in accordance with the terms of the contracts.

19 Q. What measures does the Company apply to implement these
20 projects at a reasonable cost?

21 A. The Company's processes include several controls for the
22 efficient and cost-effective implementation of the capital
23 projects. For example, the scope of each project is

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defined, and when applicable, alternatives are evaluated to develop the most cost effective solution. The Operating, Construction and Engineering organization representatives sign off on scopes and estimates. In general, outside services and equipment are purchased using a formal bidding process. A bid package that includes technical specification and a scope of work is prepared and proposals are solicited from pre-qualified vendors.

Each proposal is evaluated for compliance with the Company's technical and commercial requirements as specified in the bid documents and the lowest-cost technically qualified vendor is selected. Additional controls are imposed for construction contracts to obtain the lowest possible cost. For example, proposals for fixed-price contracts are typically requested and a separate sealed "bid check" cost estimate is prepared for contracts above a certain amount, which is used for comparison with the contractors' bids. The Bid Check Estimating Section, reporting to the Cost Management Department provides a competitive construction cost estimate, analysis and advice to the construction team to insure the best value for our customers.

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Once a project is initiated and spending begins, the construction organization coordinates the preparation of a Current Working Estimate ("CWE") for the project and monitors this throughout the project. CWE's are prepared with differing frequencies, depending on the project's overall cost, work type, and complexity. For larger scale projects, CWE's are typically prepared and reviewed monthly. For smaller scale or less complex work, they may be prepared every 2-3 months. The CWEs are reviewed by the project team to determine whether the appropriated amount is still sufficient to cover the project cost. If potential over runs are identified, the team determines the root cause of the issue and takes corrective action, such as adjusting the project scope or altering the work methods being used. The Appropriation estimate and the CWE are reviewed with the project team and incorporated in the project's Lessons Learned.

H. Productivity

Q. Was the document titled "Actual and Projected O&M Expenditures vs. 2007 Base with Inflation Added" prepared under your direction and supervision?

A. Yes. It was.

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1 Q. And what does this exhibit show?

2 A. It shows the variance between our historic and projected
3 electric T&D O&M expenses for 2007-2012, as well as our
4 2013-2017 O&M funding requests, versus what those requests
5 would have been if our 2007 O&M spending had tracked actual
6 and projected inflation rates over that same time period.
7 Our 2007 historic actual O&M costs, which were the lowest
8 of our prior historic five-year period, were \$402.3
9 million. If we apply the actual inflation rates
10 experienced for 2007-2012, and our projected inflation
11 rates for 2013-2017, our required O&M funding levels would
12 grow to \$498.6 million by 2017, or roughly 2% annually.
13 However, our actual O&M funding level requested in 2017 is
14 only \$449.5 million, which represents an annual increase of
15 approximately 1%, half the level of annual inflation. This
16 is further evidence of our commitment to cost management,
17 and improved productivity that we constantly strive for.

18 Q. Is your performance versus inflation the only item to note
19 in this respect?

20 A. No, it is important to note that we have not only
21 outperformed inflation, but have done so while our system
22 has been increasing in size and customers. This translates
23 to more equipment to inspect and maintain, and should

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1 result in higher operations and maintenance costs.

2 However, as can be seen from the exhibit, our increases
3 have been and are expected to be quite moderate in this
4 regard.

5 Q. Can you give us some examples of how the system has grown
6 in this time frame?

7 A. Yes. The number of connected customers has increased by
8 approximately 100,000 from 2007-2011, from 3.24 to 3.34
9 million, or an increase of 3%. If we look at some of our
10 major equipment classes, we have seen the following growth
11 during the same timeframe:

- 12 • Transmission and Area Substation - 7.4%
- 13 • Distribution Class Substation Breakers - 18%
- 14 • Transmission Class Substation Breakers - 10%
- 15 • Transmission and Area Substation Transformers and
16 Regulators - 6%
- 17 • 2nd Contingency Networks - 5%
- 18 • Electric Duct Miles - 4%
- 19 • Underground Distribution Transformers - 11%
- 20 • Distribution Feeders - 5%
- 21 • OH Distribution Transformers - 6%

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1 Q. Please describe the efforts that have enabled the Company
2 to achieve these productivity gains.

3 A. We strive to achieve productivity gains wherever possible
4 as part of our annual budget preparation and review
5 process. Each organization is required to identify and
6 discuss, as part of their budget presentation, specific
7 cost-saving and business process improvement initiatives
8 that will result in cost saving. Organizations discuss how
9 initiatives enhance efficiency and effectiveness, the scope
10 and breadth of the initiative and its impact on
11 customers/stakeholders, and (to the extent practicable)
12 quantify actual savings compared to prior years, current
13 guidance and current forecast. Some examples of recent
14 productivity improvements that were identified related to
15 the T&D O&M budgets include:

- 16 • Reductions in material and supply costs through the use
17 of Boeing LEAN principles, such as parts kitting and
18 enhanced inventory controls;
- 19 • Improvements in hours/unit productivity on preventive
20 maintenance items due to process changes. Equipment
21 types include Ground and Test Breakers, Cap Bank

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1 Breakers, Transmission Breakers, Substation DC Systems,
2 Transmission Manhole inspections;

- 3 • Adjustment of maintenance intervals on items such as SF6
4 gas testing, Ground and Test Breakers, 13 and 27kV
5 Substation Breakers, Air Compressor Receiver Inspections;
- 6 • Reductions in substation operator coverage by optimizing
7 requirements for adverse weather events and sensitive
8 station coverage;
- 9 • Reductions in O&M costs due to capital investment for
10 equipment such as high voltage breakers, pipe type
11 transmission feeders, pumping plants, disconnect
12 switches, and bulk power transformers;
- 13 • Our safety performance has also helped drive our
14 productivity improvements, with a 55% reduction in lost
15 work days due to work related injuries and illnesses from
16 2007-2011. The decrease of over 2,000 lost work days
17 equates to almost \$2 million saved annually;
- 18 • Implementation of advanced technologies to reduce the
19 time required to locate faults on distribution feeders;
- 20 • Integration of data from various systems into
21 consolidated displays for control center operators to
22 improve the efficiency of distribution operations;

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- 1 • Mobile platforms for field personnel to provide up to
- 2 date, real time mapping and system status information to
- 3 increase time on task;
- 4 • Use of remote monitoring systems to help assess equipment
- 5 condition and optimize inspection cycles;
- 6 • Cross training of personnel to allow crews from one
- 7 department to perform work another department. Some
- 8 examples of work performed are transformer vault roof
- 9 fabrications, 4kV unit switching and installations of
- 10 RMSPTO devices; and
- 11 • Improved assessment and prioritization of structural
- 12 deficiencies which reduce the contractor repair costs.
- 13 Q. Does the Company's rate filing reflect a productivity
- 14 imputation?
- 15 A. Yes, the filing reflects a one percent (1%) labor-
- 16 productivity adjustment.
- 17 Q. What is the labor-productivity adjustment reflected in
- 18 current electric base delivery rates?
- 19 A. The current adjustment is two percent (2%).
- 20 Q. What is the basis for reducing the adjustment from 2% TO
- 21 1%?

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1 A. There are several reasons. First, a 1% productivity
2 adjustment is the adjustment routinely applied by the
3 Commission in utility rate proceedings. The Company
4 believes there to be no circumstances unique to this filing
5 that warrant a higher imputation. For example, the
6 Commission first adopted the 2% imputation for Con Edison
7 electric service in its 2009 Rate Order in Case 08-E-0539.
8 In support of a 2% imputation, the Commission stated (pp.
9 37-38):

10 Fair and reasonable rates should be fashioned in a way
11 that better reflects the existing harsh economic
12 environment and requires the Company, as a good
13 corporate citizen, to act in ways that better
14 contribute to improving that environment and
15 demonstrate a commitment to operating as efficiently
16 as possible in providing electric delivery service.
17 We conclude that, in addition to reflecting the
18 Company's greatly increased capital investment levels,
19 a 2% productivity imputation will help achieve that
20 goal and better balance the interests of ratepayers
21 and the Company.

22
23 The "existing harsh economic environment" at the time of
24 the 2009 decision, which also prompted the Commission to
25 make other rate adjustments, including a \$60 million
26 austerity adjustment, is not reflective of today's
27 improving economic conditions. The current Commission-
28 adopted rate plan itself reflects a phasing out of
29 austerity adjustments.

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1 Second, testimony in this case by various witnesses,
2 including the Management Audit Panel, demonstrates a
3 Company commitment "to operating as efficiently as possible
4 in providing electric delivery service." That commitment
5 manifests itself in a variety of ways, including forecasted
6 capital expenditures that have declined or remained
7 essentially flat compared to the levels forecasted when the
8 2% productivity adjustment was developed.

9 Finally, the Commission stated in the 2009 Rate Order
10 (p. 36):

11 The usual 1% productivity adjustment applies in the
12 absence of clear and convincing evidence that
13 potential productivity improvements have been factored
14 into a company's forecast of rate year operations.

15
16 As discussed above, and by the Company's Accounting
17 Panel, the Company's presentation in this case demonstrates
18 that productivity improvements have been factored into the
19 rate request. We further note that these productivity
20 improvements are in addition to savings from the Work
21 Management Program, also reflected in the rate request.
22 Accordingly, there is no basis for a 2% labor-productivity
23 imputation and arguably no basis for a 1% labor-
24 productivity adjustment either. Notwithstanding, for

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1 purposes of this proceeding, the Company is accepting a 1%
2 adjustment consistent with historic practice.

3 Q. How will you present the Company's projected capital and
4 O&M expenditure requirements?

5 A. Our projected capital and O&M planned expenditure
6 requirements are presented under the following ten themes:

7 **New Business** - Projects directly involved in connecting
8 customers to our Electric system.

9 **System Expansion** - Projects to increase system capacity or
10 to provide new facilities or upgrades of existing
11 facilities caused by customer demand growth. Examples are
12 new substations, load transfers, and feeder, cable and
13 transformer upgrades.

14 **Replacement** - Replacement of equipment which fails in
15 service such as primary and secondary cable or wire,
16 services, transformers, and meters. In addition,
17 replacement work includes replacement of defective
18 components, in imminent danger of failing, that are
19 identified during inspection programs and require immediate
20 replacement as soon as system conditions permit.

21 **Reliability** - Projects that support the reliability and/or
22 availability of a facility or an operational function.
23 Reliability projects include installation of sectionalizing

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switches, the replacement of poorly performing assets, transmission feeder re-conductoring, and the refurbishment of existing facilities and various corrosion mitigation systems. Since system reliability is closely linked to reducing risk, this category also includes programs that address safety issues such as vented manhole cover installations.

Information Technology - Projects which utilize computer systems to enhance operations, maintenance, security, reliability and efficiency.

Facility Renovation - Projects associated with building improvements.

Municipal Infrastructure Support - Projects related to the relocation of Company facilities primarily due to sewer and water main replacement or upgrade.

Environmental - Programs and projects designed to decrease the likelihood of chemical releases, or mitigate the near and long term impact of a chemical release.

Equipment Purchases - Costs associated with equipment purchases by operating organizations such as transformers, network protectors, switches and meters.

Other - Projects undertaken for various reasons, which are not specifically addressed elsewhere in these descriptions.

**VI. New Business and System Expansion Capital and O&M
Expenditure Requirements**

Q. Was the 4-page exhibit, titled, "Ten-Year Peak Demand Forecast (2013-2022)" prepared under your direction?

A. Yes, it was.

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Q. Please describe the load growth and electric demand forecasts for Con Edison's service territory.

A. Total electric demand in Con Edison's service territory is expected to grow at approximately 1.3 percent per year over the next five years (2013-2017). Demand side management programs are projected to deliver 305 MW of system peak demand reductions over this five-year period. These programs are also projected to result in 365 MW of demand reductions between the 2013 and 2022 timeframe. Construction in both commercial and residential neighborhoods throughout the region continues to influence load growth projections. In 2012, there were approximately 3.5 million households in New York City and Westchester combined. The current ten-year forecasted compound annual growth rate for new housing in the area is 0.3 percent,

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1 which corresponds to an increase of approximately 112,000
2 households by 2022.

3 Examples of new construction projects in our service
4 territory include: the development of downtown Brooklyn,
5 the continued redevelopment of lower Manhattan; major
6 residential developments, such as Ridge Hill Development in
7 Westchester and the Hunter's Point waterfront development
8 in Queens; the continued development of
9 Greenpoint/Williamsburg in Brooklyn, the additional power
10 for the Brooklyn cruise ship terminal, the renovation of
11 the Brooklyn Navy Yard; and the expansion of the Hunt's
12 Point produce market in the Bronx.

13 In addition, large transportation and municipal
14 projects currently underway require expansion of Con
15 Edison's distribution system to meet the increased energy
16 needs. These projects include: the Long Island Railroad
17 Eastside Access to Grand Central Station, the extension of
18 the No. 7 Subway line, the Second Avenue Subway project,
19 continued expansion of JFK and LGA airports, the Tallman
20 Island water pollution control plant in Queens, and the
21 Croton Water Filtration Plant in Westchester.

22 Q. Please describe what is shown on page 1 of Exhibit __ (IIP-
23 2).

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1 A. Exhibit __ (IIP-2) page 1 shows the effect on the 2012
2 System Forecast of peak demand reductions projected as a
3 result of demand side management initiatives. The upper
4 line represents the Con Edison service area peak demand
5 forecast for the years 2012 through 2022 without the impact
6 of demand side management programs. The five-year average
7 annual growth rate (from 2012-2017) of this forecast is
8 1.6%, and the ten-year average annual growth rate (from
9 2012-2022) is 1.4%. The lower line represents the service
10 area peak demand forecast including the impact of 305 MW of
11 demand side management reductions projected by the Company,
12 as previously discussed. The five-year average annual
13 growth rate (from 2012-2017) is 1.3%, and the ten-year
14 average annual growth rate (from 2012-2022) is 1.2%.

15 Q. Please describe what is shown on pages 2 and 3 of Exhibit
16 __ (IIP-2).

17 A. Pages 2 and 3 of this exhibit show what would happen if we
18 were to suspend our current DSM and DR initiatives, and if
19 no investment is made to install additional capacity in our
20 system. We can see that, if this were to come to pass, 10
21 of our 62 area substations would have loads that exceed
22 their capability. The maps on the left show the projected
23 loadings of New York City and Westchester area substations

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1 in summer 2021 without implementation of substation load
2 relief beyond 2012. As can be seen, 10 of the area
3 substations will exceed their capabilities. The maps on
4 the right show the projected loadings of area substations
5 in summer 2021 with the completion of the Company's current
6 substation load relief construction planned for the next
7 ten years, including those measures reflected in the
8 Company's rate year revenue requirement in this case. All
9 of the area substations will be within their design
10 capabilities.

11 The forecasted savings in transmission and
12 distribution expenditures assume economic changes and
13 demand side management as well as other changes occurring
14 in the Company's territory that affect load growth. Should
15 these impacts reverse or demand side management programs
16 not be implemented or be implemented later than currently
17 anticipated, capital requirements for T&D would likely need
18 to increase.

19 Q. Please describe what is shown on page 4 of Exhibit __ (IIP-
20 2).

21 A. Page 4 of Exhibit __ (IIP-2) depicts our T&D capital
22 spending from 2007 through 2011 and our T&D capital
23 forecast from 2013 through 2017. The forecast, which

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1 includes projected storm hardening expenditures, reflects
2 reduced capital infrastructure spending overall when
3 compared to the prior 5 year actual period. The near and
4 long term capital investments support customer demand and
5 upgrades on our infrastructure to maintain reliability and
6 safety.

7 Q. I show you a document titled, "Electric T&D - New Business
8 & System Expansion" and ask whether that document was
9 prepared under your direction?

10 A. Yes, it was.

11 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-3)**

12 Q. What does Exhibit __ (IIP-3) show?

13 A. Exhibit __ (IIP-3) lists the capital program and project
14 funding requirements that support New Business and System
15 Expansion work conducted by System and Transmission
16 Operations (S&T0), Substation Operations (Transmission and
17 Area Substations), and Electric Operations (Distribution
18 System) for the years 2013 through 2017. The exhibit also
19 provides five year historic spending for 2007-2011 and a
20 2012 end of year projection for New Business and System
21 Expansion programs and projects. The exhibit presents O&M
22 program changes for New Business and System Expansion. The
23 exhibit also contains "white papers" for each capital

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program and project that provide more detailed information such as: program and project work description, justification, alternatives, estimated completion date, current status, and forecasted funding.

A. System and Transmission Operations System Expansion

1. System and Transmission Operations System Expansion Capital Programs and Projects

a) Projects Addressing Demand Growth

Q. Please describe the Transmission Operations programs listed under "System Expansion" on Exhibit __ (IIP-3).

A. Transmission Operations' has one capital project to address projected demand growth: **Dynamic Feeder Rating ("DFR")**. DFR systems expand the capabilities of transmission feeders under certain operating conditions thereby allowing greater power transfers. This is a multi-year program to install a new DFR system on selected feeders. DFR Systems consist of instrumentation installed on select feeder components to monitor data pertinent to feeder thermal capabilities, remote terminal units to process the various instrumentation installations, communication systems to transfer the processed data, and central processing units which control the system and provide the dynamic ratings.

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1 In addition to the hardware, custom mathematical modeling
2 and software development are required to provide an
3 operational system. This program has served to improve
4 both normal and contingency capabilities on our
5 transmission system and, in doing so, has improved both
6 reliability and economic flows. We plan to install one DFR
7 system per year at a projected capital cost of \$1.5 million
8 annually during 2013 through 2017.

9 **b) Projects Addressing Generation Retirement**

10
11 Q. Is the Company requesting funding due to any needs for new
12 transmission lines?

13 A. Yes. The Company is requesting funding to complete work on
14 Feeder 34091, as well as the installation of a new Rainey
15 to Corona Feeder.

16 Q. What is driving the need for this work?

17 A. US Power Generating Company (US Power Gen) is a merchant
18 generation facility whose steam generation units (2, 3, 4 &
19 5) are connected to Con Edison's Astoria East and Astoria
20 West Substations. Unit 4 experienced a boiler explosion on
21 July 27, 2011 and has been out-of-service since the
22 explosion. On February 14th, 2012, US Power Gen provided a
23 six month notice of their intention to mothball the unit.

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1 They had previously filed an official notice with the New
2 York Independent System Operator ("NYISO") mothballing Unit
3 2 until further notice stating that the unit was unsafe to
4 operate.

5 The unavailability of Astoria Units 4 and 2 results in
6 an approximate 200MVA deficiency to the Astoria East/Corona
7 Transmission Load Area and did not meet our N-1/-1
8 operating criteria during the summer 2012 peak demand. The
9 Astoria East/Corona Transmission Load Area consists of the
10 Long Island City, Flushing, Jackson Heights, and Rego Park
11 networks. These networks supply critical customers such as
12 the Metropolitan Transit Authority ("MTA"), the Long Island
13 Rail Road, LaGuardia Airport, local area hospitals, as well
14 as all of the commercial and residential customers in these
15 areas.

16 Q. How does the Company intend to address the deficiency?

17 A. The Company is addressing this deficiency in three phases.
18 Phase 1 is a project to connect a new 138kV supply feeder
19 (feeder 34091) from the NYPA owned 345kV Astoria Annex
20 Transmission Station to the 138kV Astoria East Substation
21 via a new step-down Autotransformer and a 138kV Phase Angle
22 Regulator ("PAR"), using a combination of overhead cable
23 and buried solid dielectric feeders. This work was

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completed prior to the summer of 2012, and included installation of the new equipment as well as ancillary components such as pothead stands, relay protection, and containment structures. The cost of Phase 1 work is expected to total \$27.5 million. While the physical installation is now complete, we are still in the process of purchasing a PAR and transformer to replace the units that were installed, as these were drawn from our spare transformer inventory.

The 138kV feeder 34091 terminates in Astoria East in the bus section between Circuit Breakers 1W and 2W. Currently, feeder 34G02 (the outlet of Astoria Unit 2) is connected to this bus section. The new connection to this same bus is designed in a manner such that none of the 34G02 equipment is either modified or rendered inoperative. The design allows for Astoria Unit 2 to come on-line at any time, even with the new feeder 34091 being connected to the same bus.

Q. Are you planning any additional work in relation to the Phase 1 installation?

A. Yes, the Phase 1 connection was conditionally permitted due to long lead time for 345 kV SF6 bus to meet the scheduled service date of summer 2012. Con Edison Transmission

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1 Planning Criteria does not allow tee tapping of
2 transmission feeders to establish a permanent supply into
3 our transmission system. Therefore, a new independent **345**
4 **kV supply side connection from the Astoria Annex substation**
5 needs to be established prior to the summer of 2013 to
6 comply with our Transmission Planning Criteria. Phase 2 of
7 the project will establish this connection by installing
8 SF6 bus to tap the section between breakers 3 and 5 at the
9 Astoria Annex to provide a position independent of 345kV
10 feeder Q35M, reconnecting the overhead 345kV auto-
11 transformer primary feeder to the SF6 bus to air bushings
12 of the newly provided position, and modifying the relay
13 protection system to be consistent with the new position at
14 the Astoria Annex. Phase 2 is expected to be completed
15 prior to the summer of 2013, at a total cost of
16 approximately \$14 million.

17 Q. Please discuss Phase 3 of this project.

18 A. Phase 3 of the project will upgrade the autotransformer and
19 phase angle regulator foundations and spill containments,
20 move the overhead portions of the feeder to underground,
21 and change the connection point at the Astoria East
22 Substation. Phase 3 is expected to be initiated in 2014
23 and completed in 2017. The projected capital expenditures

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1 to complete Phase 3 are \$6 million in 2014, \$15 million in
2 2015, \$19.3 million in 2016, and \$12 million in 2017.

3 Q. Will any additional work need to be performed to address
4 the deficiency?

5 A. Yes. To address the longer term deficiency, which begins
6 to appear in 2017 and continues to grow thereafter, we are
7 planning to install a 345/138 kV phase angle regulator
8 controlled 138kV solid dielectric feeder interconnection
9 between the Rainey 345 kV Substation and the Corona 138 kV
10 Substation. This would address the design requirement
11 deficiencies for both the Astoria East/Corona and the
12 Jamaica/Corona Transmission Load Areas. The additional in-
13 City 345/138 kV transmission path could also reduce energy
14 price congestion within the NYISO's New York City zonal
15 area.

16 In order to install a new **138kV transmission line**
17 **between Rainey 345kV Substation and Corona 138kV**
18 **Substation**, bus sections in both stations will need to be
19 established. The creation of a bus section in Rainey
20 Substation will require the addition of a 345kV circuit
21 breaker, bus, relay protection, and termination stands for
22 the new feeder. The 345/138 kV transformer and 345/138 kV
23 phase angle regulator will be installed in the vicinity of

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1 Rainey Substation. At Corona Substation, the creation of a
2 bus section will include the addition of 138kV circuit
3 breakers, bus, relay protection, and terminal stands for
4 the new feeder.

5 The new 138kV solid dielectric feeder installation, to
6 interconnect the Rainey and Corona Substations, is expected
7 to be a seven mile route to be installed underground via a
8 trench and conduit system. One major crossing will be
9 below the Brooklyn Queens Expressway. The total cost of
10 this work is currently projected to be \$213 million, with
11 the largest component of the cost being the feeder
12 installation. This work is expected to begin in 2015 and
13 be completed in 2017. The projected capital expenditures
14 to complete this project are \$67 million in 2015, \$73
15 million in 2016, and \$73 million in 2017.

16 c) Future Generation Retirement

17 Q. Does the Company have any concerns regarding the impact of
18 other in-city generators that could become unavailable due
19 to mothballing or retirement over the next several years?

20 A. Yes. In 2011, Con Edison was faced with the removal from
21 service of Astoria generating units 2 and 4, as well as the
22 loss of Astoria Gas Turbine units 10 and 11 and Ravenswood

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1 Gas Turbine Unit 3-4. We were also informed that the
2 owners of Gowanus Barges 1 and 4 will be conducting
3 strategic reviews of these assets, and we could be losing
4 this capacity as well. We currently have plans in place to
5 address all shortfalls that we are aware of, such as the
6 previously discussed installation of Feeder 34091, which
7 was performed to address the loss of Astoria generating
8 units 2 and 4.

9 Against this backdrop, we are studying the loss of
10 various in-City generating capacity. The studies will be
11 used to determine what types of solutions would be
12 required, as well as their costs, so that we would be
13 better positioned to react to these issues should they
14 develop.

15 Q. Have these studies been initiated?

16 A. Yes, a preliminary study examining the loss of each of the
17 units that provide generating capacity within the Con
18 Edison service territory was performed. A special emphasis
19 was placed on the older steam/electric generating units
20 within our system, as we feel these are more likely to be
21 retired, given their current efficiency and utilization
22 rates.

23 Q. And what were the results of this study?

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1 A. We determined that four load pocket areas of particular
2 concern exist. The tentative solutions that would be
3 required to mitigate the shortfalls that would be created
4 within these areas are variable, but each requires
5 substantial investment ranging from approximately \$100
6 million to \$300 million.

7 Q. Is the Company seeking funding in this proceeding to move
8 forward with any of these mitigation efforts at this time?

9 A. We cannot reasonably predict that any of the generation we
10 see as potentially being retired will be retired within the
11 time horizon relevant to this proceeding. We have not
12 included in this filing any proposed projects or programs
13 to provide funding that would be needed in the event any of
14 these scenarios occur.

15 Q. Are there any other concerns of note that you have
16 regarding loss of generation?

17 A. Yes. Along similar lines, the outcome of the relicensing
18 efforts of Indian Point Units 2 and 3 is still unclear. We
19 have performed preliminary studies to develop and evaluate
20 potential solutions to make up for loss of this 2000MW of
21 generating capacity, should the relicensing efforts be
22 unsuccessful.

23 Q. And what are the results of your studies?

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1 A. Our studies show that impacts from the Indian Point
2 shutdown will affect neighboring utilities and other
3 agencies, such as NYPA, and that solutions will depend on
4 when the shutdown happens and will require intervention
5 beyond Con Edison alone. We have not included in this
6 filing any proposed projects or placeholder programs to
7 provide funding that would be needed in the event that
8 Indian Point Units 2 and 3 are shutdown.

9 Q. What is the Company's proposal for recovery of capital
10 investments and O&M expense that may be incurred to address
11 the retirement or mothballing in-City generation or the
12 shutdown of Indian Point Units 2 and 3?

13 A. Because of the very real possibility of but uncertainty
14 about these events, we request that the Company be
15 authorized to defer for future recovery the carrying
16 charges on any capital investments expense that it incurs
17 for these items to the extent that such expenditures would
18 cause the Company to exceed the average net plant reflected
19 in rates to be set in this proceeding. If any O&M costs
20 incurred for such items result in a change in Con Edison's
21 annual electric costs or expenses not anticipated in the
22 expense forecasts and assumptions on which the rates in
23 this proceeding are based, we request that the Company be

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1 authorized to defer incremental O&M costs excluding Company
2 labor, with any such deferrals to be reflected in the next
3 base rate case or in a manner to be determined by the
4 Commission.

5 **2. PJM Open Access Transmission Tariff (OATT) Wheeling**
6 **Service**

7 Q. Are there any other electric transmission items you would
8 like to discuss?

9 A. Yes. We have contracted for PJM Open Access Transmission
10 Tariff ("OATT") Wheeling Service for the delivery of 1,000
11 MW of firm transmission service. This service commenced in
12 May 2012, upon expiration of a prior contractual wheeling
13 service by Public Service Electric & Gas Company. The new
14 service will be rendered pursuant to the rates and terms of
15 PJM's OATT. It has an initial term of five years and
16 additional five-year terms at Con Edison's option.

17 Q. Why did the Company subscribe to this PJM wheeling service?

18 A. The Company contracted with PJM for the new OATT service
19 because of the significant reliability and economic
20 benefits that it provides. The OATT service increases the
21 firm transmission capacity available for importing energy
22 into New York City by 1,000 MW. That incremental capacity
23 supplements the existing transmission and generation

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resources available to serve the Company's customers, thereby enhancing reliability by providing a base resource and contingency coverage for the loss of other supply resources. Moreover, the new service utilizes a transmission corridor that is remote from the Company's overhead transmission facilities that extend from Pleasant Valley into New York City. The use of a separate corridor mitigates the risk of losing multiple supply resources because of a single event (such as a lightning strike).

The incremental energy supply provided by the new PJM OATT service benefits consumers economically by reducing market prices. In approving the new PJM service, the FERC found that, based on market prices in New York City as compared to other areas, the 1,000 MW service provides economic benefits (in addition to reliability benefits) in the vast majority of the hours each year. *PJM Interconnection, LLC*, 132 FERC ¶ 61,221, P 71 (2010).

Q. Are the economic and reliability benefits generally recognized?

A. Yes. FERC concluded that PJM's then-proposed service to Con Edison was just and reasonable, based on a broadly supported settlement agreement. The NYISO supported the settlement because it provided dependable power deliveries

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1 that diversify power supplies and enhance reliability. The
2 City of New York argued that PJM's OATT service would
3 provide critical reliability benefits to New York City and
4 New York State and would provide economic benefits
5 (including a 10 percent reduction in the locational
6 capacity reserve requirement). The PSC supported the
7 settlement agreement on the grounds that the new PJM OATT
8 service provides critical reliability and consumer benefits
9 and is an anticipated part of the Company's energy supply
10 structure. These comments were submitted in FERC Docket
11 No. ER08-858-000.

12 Q. Is the cost that the Company incurs for the new PJM OATT
13 transmission service reasonable?

14 A. Yes. Relative to the reliability and economic benefits
15 derived from the service and relative to the costs of the
16 alternatives to PJM's OATT service, the cost of the new PJM
17 OATT service is reasonable and justified. The service
18 utilizes existing transmission ties between New York and
19 New Jersey, thereby avoiding the need to build new
20 transmission facilities into New York City.

21 The Champlain Hudson Power Express, Inc. ("CHPE")
22 project illustrates the capital investments that
23 alternatives to the PJM OATT service would require. The

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1 project would deliver 1,000 MW of Canadian hydro-power and
2 wind power to New York City. The PSC staff has estimated
3 the capital cost of the CHPE project to be \$2 billion for
4 the HVDC cable from the Canadian border to the NYPA's
5 substation in Astoria and an additional \$194 million for a
6 transmission feeder connecting the NYPA substation to the
7 Company's Rainey substation. See, *Champlain Hudson Power*
8 *Express, Inc.*, February 24, 2012, Joint Proposal. In
9 contrast, the PJM OATT service does not entail any up-front
10 capital investment, and its monthly service charges
11 (currently approximately \$3 million) are small in
12 comparison to the comparably sized alternative
13 arrangements, most of which would have involved both up-
14 front capital costs and on-going service charges.

15 Q. Does the Company propose to recover the cost of the new PJM
16 OATT service through the MAC?

17 A. Yes. As discussed in the Electric Rate Panel testimony,
18 the Company regards the PJM charges as transmission-related
19 costs that qualify under MAC item 14 (Leaf 339).

20 **3. System and Transmission Operations System Expansion**
21 **O&M Program Changes**

22 Q. Are there any O&M Program changes required to support
23 System Expansion?

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1 A. Yes. System and Transmission Operations is projecting it
2 will incur \$100,000 annually to add one additional staff
3 position to the Transmission Planning Department,
4 Interconnections Services Section.

5 Q. Why is this additional staff member required?

6 A. Con Edison responsibilities related to Interconnection
7 Services continue to grow, with the anticipated increase in
8 NYISO developer projects, and compliance with FERC Order
9 1000, and related activities. It is anticipated that the
10 new developer projects and current legacy / carryover
11 interconnection activities will increase by 20 to 40
12 percent. This will necessitate a one FTE staffing addition
13 to the Interconnection Services Section to manage the
14 Company's NYISO tariff obligations and contractual
15 compliance-related activities.

16 Q. What functions will be assigned to this position?

17 A. This function will be responsible for the following
18 functions:

- 19 • Management of NYISO Interconnection Tariff processes,
20 requirements and mandates including.
 - 21 o performance of the requisite technical studies and
 - 22 evaluations relating to NYISO Attachment X
 - 23 Interconnection Tariff

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- 1 o drafting and internal review of interconnection
- 2 contractual obligations
- 3 • Company representation at NYISO committee meetings
- 4 • FERC Order 1000 compliance including
- 5 o reliability and economic benefit evaluation of inter-
- 6 and intra- regional project
- 7 o development of cost allocations for projects outside
- 8 the Company's territory
- 9 • BPS Performance and Analysis Support including
- 10 o maintain load flow, short circuit and stability
- 11 models;
- 12 o perform steady state analysis, short circuit analysis
- 13 and stability analysis for both near and long term
- 14 Planning Horizons - under peak and light load
- 15 conditions;
- 16 o perform sensitivity analysis for all base conditions
- 17 (such as generation retirements) to test the system
- 18 response; perform System Impact Studies (SIS) for
- 19 projects that were identified as a solution to an
- 20 identified reliability need.
- 21 o calculation of thermal, voltage and stability
- 22 limitations for the System Operating Limits.

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1 o documentation towards NERC compliance requirements

2 Q. Does this conclude your testimony regarding System and
3 Transmission Operations capital programs and projects and O&M
4 Program changes required to support System Expansion?

5 A. Yes. The Panel will now review Substation Operations
6 initiatives supporting "New Business and System Expansion."

7 **B. Substation Operations System Expansion**

8 **1. Substation Operations System Expansion Capital**
9 **Programs and Projects**

10 Q. Please discuss Substation Operations projects and programs
11 related to System Expansion.

12 A. Despite the forecasted increase in demand, there is a
13 limited need to provide additional substation capacity
14 during the next five years due to a combination of

- 15 1. Increased substation capacity achieved since 2010,
16 2. Deferral strategies,
17 3. Demand side management, demand response, energy
18 efficiency, and distributed generation.

19 We do have a number of smaller scale load relief projects
20 that will be required, and our ongoing E179th Street
21 substation refurbishment will also provide substantial
22 additional required capability at that station.

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1 Q. Please describe the substation load relief projects that
2 will be implemented in order to meet system expansion
3 needs.

4 A. We will discuss projects at our substations in Manhattan,
5 the Bronx, Brooklyn and Staten Island.

6 In the near term, we have two Manhattan area
7 substation capability shortfalls to address in 2013. **West**
8 **19th Street** is projected to experience a 5 megawatt (MW)
9 shortfall, and **Avenue A** is projected to experience a 3 MW
10 shortfall unless additional capability is added to these
11 stations. In order to do this, we will replace limiting
12 syn bus sections at each station. This will provide an
13 additional 24MW of capability at West 19th Street, and an
14 additional 12MW of capability at Avenue A. This work will
15 be performed during 2013 at a cost of \$500,000 at each
16 station.

17 Longer term, we intend to install the 5th transformer
18 bank at **Astor Substation** in 2018, in order to provide an
19 additional 85MW of capacity there, as well as address 138kV
20 feeder load imbalances that provide some limitation in the
21 area substations fed by West 49th Street, particularly West
22 65th Street No. 2. This additional capacity will allow for
23 the transfer of the Rockefeller Center network from West

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1 65th Street No. 2 to Astor, relieving capability shortfalls
2 that would be developing at that station. Work on this
3 project will begin in 2016 at a projected cost of \$2
4 million and will continue in 2017 at a projected cost of \$5
5 million.

6 In addition to the feeder load imbalances noted above,
7 **West 65th Street No. 2** will also require the installation of
8 an additional 20 MVAR's of capacitors to address a 6MW
9 shortfall that is projected in 2018. This work will be
10 performed in 2017 at a projected cost of \$1.6 million in
11 2017.

12 We are expecting a 5MW station capability shortfall to
13 develop at the **East 75th Street Substation** by the year 2018.
14 To relieve this, we will install additional cooling on
15 transformers 1 and 3, which will provide an additional 6MW
16 of capacity. This work will be performed in 2017 at a
17 projected cost of \$.75 million.

18 We plan to install a second capacitor bank at the
19 **Murray Hill Substation** in 2018. This second capacitor bank
20 will provide 138kV feeder load relief for the Manhattan
21 feeders coming from our Vernon transmission station. These
22 feeders will experience a 5MW shortfall in capability by
23 2018, and the Murray Hill project will provide 8MW of

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1 additional capacity. This work will be performed in 2017
2 at a projected cost of \$1.1 million.

3 Q. Please discuss the substation load relief projects planned
4 for the Bronx beginning with the planned work to maintain
5 the reliability and upgrade the capability of the East 179th
6 Street area substation.

7 A. The **East 179th Street Substation**, which supplies the central
8 and north Bronx area, was placed in service in 1956 and is
9 one of the few area stations with outdoor switchgear and
10 underground protection and control equipment. Being an
11 outdoor substation, the weather has taken its toll on the
12 physical structures that house the equipment as well as its
13 wiring. The substation is nearing the end of its useful
14 life, and the Company evaluated two possible replacement
15 options:

16 1. Replace the switchgear and wiring in its current
17 setting.

18 2. Construct a new switchgear building to house the
19 new switchgear indoor.

20 A third option of transferring load to a nearby substation
21 and retiring the existing station was determined to be not
22 feasible due to lack of spare capacity at nearby stations.
23 Option 1 was selected and approved, as it was much less

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1 costly and provided similar reliability levels. The plan
2 is to replace/upgrade the switchgear and associated wiring
3 to maintain the reliability required for the network load
4 area supplied by the substation.

5 The East 179th Street substation will develop a 3MW
6 capability shortfall in 2016. To alleviate this shortfall,
7 we plan to install water spray cooling on transformer 5 in
8 2015 and 2016 at a projected cost of \$.5 million each year.
9 And we plan to install forced air cooling on the bus,
10 breaker, and reactor associated with transformer 4 in 2015
11 and 2016 at a projected cost of \$.75 million each year.
12 These upgrades will provide an additional 9MW of
13 capability.

14 The station load will again exceed its capacity in
15 2019, by 3MW. Without any mitigation, this shortfall would
16 continue to grow, reaching 20MW by 2024 and 36MW by 2028.
17 Because all nearby substations will be at or near capacity,
18 load cannot be transferred. The only alternative is to
19 upgrade the capacity of the existing station. This
20 upgrade, which involves installing new breakers, bus, and
21 wiring for the East 179th Street 13kV station, will provide
22 an additional 63MW of capacity at the substation. This
23 project is being coordinated with transformer replacements

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1 scheduled at E179th Street that will be done via our
2 Transformer Replacement Program, reflecting an overall
3 revised completion date of 2021 for the entire scope of
4 work (reliability and capability upgrade). The preliminary
5 order of magnitude estimate for this project is \$108
6 million. To date, \$60 million has been appropriated for
7 long lead equipment and preliminary work phases. The
8 projected cost of this project during the 2013-2017
9 timeframe will be approximately \$66 million.

10 Q. Are there other projects planned in the Bronx to address
11 New Business and System Expansion?

12 A. Yes. The Parkchester No. 1 and Parkchester No. 2
13 Substations will start to experience capability shortfalls
14 in 2018, starting at 3MW in 2018, and growing to 33MW by
15 2021. To alleviate these shortfalls, we will install a
16 fourth transformer and eight new feeder positions at
17 **Parkchester No. 2** in 2018, which will provide an additional
18 80MW of capacity. This will relieve the immediate
19 shortfall at Parkchester No. 2, and allow future shortfalls
20 in Station No. 1 to be addressed via load transfers from
21 Station No. 1 to Station No. 2. The projected capital
22 costs of this project are 8.8 million in 2016 and \$10.2
23 million in 2017.

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1 Q. What load relief work is planned for Brooklyn area
2 substations?

3 A. We expect a 2MW shortfall to develop at the **Plymouth Street**
4 **Substation** by 2017, which would grow to 18MW by 2021 if not
5 addressed. We plan to replace limiting bus sections with
6 higher rated equipment to alleviate this issue. This will
7 provide an additional 29MW of capability for the station,
8 and should handle expected load levels through 2021 and
9 beyond. This work will be performed in 2016 and 2017 at a
10 projected cost of \$3 million each year.

11 Q. Are there any other projects planned in Brooklyn?

12 A. Yes. Transmission Planning performed a study of the
13 **Greenwood Substation**, looking at equipment loading levels
14 under various contingencies at the Greenwood Substation,
15 and determined that a number of breakers, disconnects, and
16 bus sections would be overloaded and require replacement as
17 follows:

- 18 • 5 circuit breakers - 7S, 6S, 2N, 5N, and 7N.
- 19 • 6 disconnect switches - 5N4, 7N7, 1S1, 1S8, 8N7, and
20 4N4.
- 21 • 2 section of bus - between feeders 38B11 and 23161,
22 and between feeders 38B14 and 42231.

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1 This equipment will be replaced with higher rated equipment
2 that will remove the overload conditions. This work
3 started in 2012 and will be completed in 2014. The
4 projected costs of this project are \$4.3 million in 2013
5 and \$2.7 million in 2014.

6 Q. Please discuss work planned at the Greenwood substation to
7 relieve the Greenwood 138 kV transmission load area.

8 A. Due to load growth, the Greenwood 138 kV transmission load
9 area will not meet our N-1/-1 operating criteria during the
10 summer 2018 peak demand. The shortage is only on a
11 contingency basis. The solution is the installation of a
12 circuit breaker (breaker 3N) at the **Greenwood 138 kV**
13 **substation**. The circuit breaker would create the ability
14 to isolate a failure of one transmission feeder from a
15 second feeder that currently shares the same bus at the
16 substation. In addition to installing the new circuit
17 breaker, the feeders involved at the Greenwood Substation
18 bus will require repositioning of the two feeders at the
19 entry to the substation. The projected capital costs of
20 this project are \$5 million in 2014 and \$6 million in 2015.

21 Q. Are there any New Business and System Expansion projects
22 planned in Staten Island?

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1 A. Yes. The Fresh Kills 33kV substation will begin to
2 experience capability shortfalls of approximately 6MW in
3 2017. To address this shortfall, we are planning to
4 replace the feeder associated with transformer 21W. The
5 new feeder will have a larger conductor size, thus
6 increasing its ampacity. This will increase the overall
7 station rating by approximately 7MW, resolving the
8 shortfall. The projected capital cost of this project is
9 \$0.75 million in 2016 and \$0.75 million in 2017.

10 Q. Please discuss the planned upgrades at the Queensbridge
11 substation which resulted from the study of the proposed
12 Berrians GTI interconnection.

13 A. The Company conducted a transmission planning study on the
14 momentary fault duty calculations and the corresponding
15 ratings at the substations that are affected by the Class
16 Year 2011 Projects planning to connect into the Con Edison
17 system, specifically the Berrians GTI & II, and the AP
18 Dutchess Projects. The momentary fault currents had been
19 calculated based on the 2016 short circuit base cases
20 prepared by NYISO as part of the Class Year Study. These
21 results showed that **Queensbridge substation** has 11
22 disconnect switches and accompanying structures, supports,
23 and foundations which will be over-dutied. Con Edison will

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1 be responsible for upgrading these facilities. The fault
2 duty calculations for the current 2012 operating system do
3 not indicate over-dutied conditions. However, prior to the
4 addition of the Berrians GT project in 2016, the
5 Queensbridge equipment will require upgrades. The
6 projected capital costs of this project are \$3 million in
7 2014, \$4 million in 2015, and \$4 million in 2016.

8 Q. Please describe the other substation projects intended to
9 support increased customer demand.

10 A. Our **Emergent Load Relief Program** addresses unplanned work,
11 identified as a result of post-summer analysis, consisting
12 of load relief measures that may be required to meet the
13 forecasted demand for the next summer years, and that are
14 not identified in the most current 10 Year Load Relief
15 Program. Since these projects emerge as a result of post
16 summer analysis, they are not included in the prior year's
17 funding requests for the budget year in which the work must
18 be performed. Based on the most current 10 Year Load
19 Relief Program, dated June 28th, 2012, we have identified a
20 number of near-term known substation Load Relief projects
21 and the associated costs in the years 2013-2015. However,
22 our five year projection includes \$1.1 million annually in
23 2016 and 2017 for the Emergent Load Relief Program to

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1 address the likelihood that additional small scale projects
2 will emerge in the outer years of our current 5 year work
3 plan.

4 Q. Are there any developer or generator interconnection
5 projects that fall into the System Expansion category?

6 A. Yes. The ongoing **Goethals Variable Frequency Transformer**
7 **("VFT") Oversight** project involves the expansion of the
8 Goethals substation into a ring bus design, which will
9 facilitate Linden's connection with Con Edison. FERC has
10 ruled that any work Con Edison performs in support of the
11 Linden VFT project considered to be "oversight" is not
12 billable to Linden VFT. Con Edison's oversight hours
13 includes Central Engineering technical support, Substation
14 Operations ("SSO") oversight, and Project Management and
15 Inspection. It is important to note that any work Con
16 Edison performs that is not considered oversight (such as
17 terminating wires, performing trip checks, and
18 switching/tagging substation equipment) will be
19 reimbursable and is not reflected in this filing. We
20 expect this project to be completed in 2014, and forecast
21 our non-reimbursable oversight capital costs to be \$1
22 million in 2013 and \$0.8 million in 2014.

ELECTRIC

2. Transfer of Hudson Avenue Station Property from Steam Operations to Electric Operations

Q. Please discuss the transfer of Con Edison's Hudson Avenue Station property from Steam operations to Electric operations.

A. The Hudson Avenue Station ceased operation as a steam generating plant in April 2011. The equipment at the site was rendered unusable, the plant was retired in place, and the land was transferred from the Steam Plant in Service to the Electric Department, as Plant Held for Future Use.

Q. What is the remaining value of the investments made at Hudson Avenue?

A. At the time of retirement, on April 30, 2011, the book cost of the land was \$1.7 million and the book cost of the structures and equipment that was retired was \$127.5 million. The accumulated reserve for depreciation was \$35.2 million for a net book value of \$92.3 million for the structures and equipment. Further details of these amounts are shown in the exhibit titled "Hudson Avenue, Summary of Net Production Plant in Service at April 30, 2011", Exhibit ___ (IIP-4).

MARK FOR IDENTIFICATION AS EXHIBIT ___ (IIP-4)

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1 Q. With respect to the land at the Hudson Avenue Station, why
2 did the Company transfer it from the Steam operations to
3 Electric operations?

4 A. As explained by the Company's Steam Operations Panel in the
5 Company's concurrent steam rate case, the Steam Department
6 does not contemplate that the land will have a future use
7 in the Company's Steam operations and, as we will explain,
8 there are several anticipated uses for the property in the
9 Company's electric operations.

10 Q. Please describe the specific uses for the property
11 currently contemplated by the Company's electric
12 operations.

13 A. This is a unique site of 11 acres zoned M3-1
14 "Manufacturing," which is suitable for utility use. It is
15 adjacent to four existing substations, one of which is the
16 Farragut transmission station serving both Manhattan and
17 Brooklyn. Those features are important to several
18 potential future uses for this site that have been
19 identified, including:

- 20 • A Distribution Switching Station for load relief at
21 the Water Street Area Substation
- 22 • Expansion of the adjacent Farragut Substation, since
23 Farragut Station is already at its maximum capacity

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- 1 • Moving the proposed future “Manhattan Switching
2 Station” to Hudson Avenue (but still serving Manhattan
3 load)
- 4 • An interconnection point, such as a High Voltage DC
5 Converter Station, for future New York City supply or
6 generation.

7 Q. Please discuss these potential uses for the Hudson Avenue
8 site.

9 A. A portion of this site is planned to be used to install the
10 “Hudson Avenue Distribution Switching Station (“DSS”),”
11 which is planned to go in service in 2022. This station
12 will provide 238MW of capacity, and will relieve projected
13 overloads at the Water Street Substation. This 3G designed
14 station will utilize 27kV connections to existing
15 substations, in essence utilizing their excess capacity to
16 supply this station, without the need for new 138kV
17 supplies to be installed.

18 We presently anticipate moving forward with the Hudson
19 Avenue DSS as the solution for Water Street overloads.
20 However, as Brooklyn loads continue to grow, and we
21 continue to seek cost-effective ways to maintain or improve
22 our reliability levels, there may be situations where
23 expansion of the adjacent Farragut Substation would be

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1 pursued. Under certain scenarios, we may eventually
2 install Transformer 11 for the Farragut Substation, along
3 with associated breakers, bus, disconnects, and feeders.
4 Transformer 11 could be installed on the adjacent Hudson
5 Avenue site because there is limited available space for
6 such an installation at Farragut, and installing the
7 equipment within the confines of the existing station
8 footprint would likely require the conversion of a large
9 amount of equipment from open air to gas insulated, which
10 requires much less space but would be costly.

11 This transformer would ultimately supply additional
12 area substation transformers at existing area substations,
13 and could play a role in helping to defer our eventual
14 construction of a second Gowanus Transmission Substation,
15 by providing the capacity required from Farragut for a
16 number of years before we would be forced to install an
17 entire transmission substation. These issues are not
18 expected to arise for more than a decade, but having the
19 necessary land available to provide the most flexible set
20 of solutions to our load growth and reliability concerns
21 will allow us to develop the most cost-effective plans.

22 Q. Please continue

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1 A. Longer term, other potential electric system uses are being
2 evaluated. Our latest long range plans call for the
3 establishment of the West Side Switching Station sometime
4 in the period of 2024-2029, depending on load growth and
5 the success of various mitigation strategies we are
6 planning on executing to defer that project. This station
7 will provide approximately 890MW of capacity, and will be
8 used to feed several new Manhattan area substations that
9 are planned for the future – Hudson Yards, Midtown East,
10 and Lower East Side. These stations are required to
11 relieve projected overloads at a number of existing
12 Manhattan Area Substations that are supplied from the East
13 13th and West 49th Street Transmission Substations.

14 We are currently considering using the Hudson Avenue
15 site for the West Side Transmission station, and supplying
16 the new Manhattan substations via 138kV sub-transmission
17 feeders that emanate from Brooklyn. There are a number of
18 instances where sub-transmission supply feeders originate
19 in one borough and serve load in a second borough. For
20 example, the Seaport and Trade Center Area Substations in
21 Manhattan are supplied from Farragut Substation in
22 Brooklyn, and the East 75th and West 110th Street Area
23 Substations in Manhattan are supplied from Rainey

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1 Substation in Queens. Use of the Hudson Avenue site would
2 enable us to forego a major real estate purchase in
3 Manhattan to procure the necessary land for the West Side
4 station, which had an estimated cost of roughly \$135
5 million in 2008.

6 Q. Are any other uses for this property being considered?

7 A. Yes. Given this site's unique proximity to transmission
8 and area substations and feeders, as well as the Brooklyn
9 and Manhattan load areas, this site could be used to
10 support an interconnection point for future New York City
11 supply or generation. As we have discussed in our
12 testimony, there is a considerable likelihood that we will
13 need to obtain additional transmission or generating
14 capacity to respond to the retirement or mothballing of one
15 or more of the older generating stations currently on the
16 system. If this happens, the Hudson Avenue site could
17 potentially be used for an interconnection project such as
18 a High Voltage DC Converter Station which requires a large
19 footprint. The Hudson Avenue site would have adequate land
20 available to support the construction of such a station,
21 and, its proximity to suitable interconnection points would
22 make it attractive for this purpose.

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1 The current zoning designation, M3-1 Manufacturing, is
2 adequate for any of the aforementioned potential uses.
3 Given this location's unique geographic location on the
4 system, the limited availability and high cost of land in
5 New York City, and the City's seemingly constant electrical
6 demand growth, we feel confident that this property will
7 eventually serve our electrical customers cost
8 effectively.

9 Q. Who would be responsible for any future costs associated
10 with this site?

11 A. Once the property is transferred to the Electric
12 Department, Electric would responsible for any future
13 costs, such as demolition of the existing structures and
14 equipment.

15 Q. How will this property transfer benefit electric customers?

16 A. This land and location, with this type of zoning, is a
17 unique property that is well suited for in-city electric
18 needs. If Electric were to look to purchase such a site,
19 it most likely would be difficult and costly to obtain.

20 Q. Is the Company making any proposals in this proceeding
21 regarding the undepreciated cost of the retired structures
22 and equipment at the Hudson Avenue Station?

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1 A. Yes. As explained more fully in the testimony of Company
2 witness Muccilo, the Company's Accounting Panel and the
3 Company's Property Tax and Depreciation Panel, the Company
4 proposes to transfer those undepreciated costs from the
5 Steam Department to the Electric Department and amortize
6 them in electric rates.

7 Q. Does this conclude your testimony regarding Substation
8 Operations capital programs and projects required to support
9 System Expansion?

10 A. Yes. The Panel will now review Electric Operations
11 initiatives supporting "New Business and System Expansion."

12 ***C. Electric Operations (Distribution) New Business and*** 13 ***System Expansion***

14 **1. Electric Operations (Distribution) New Business and** 15 **System Expansion Capital Programs and Projects**

16
17 Q. Please discuss the Company plans to reinforce its electric
18 distribution system to support new business and system
19 expansion.

20 A. As stated previously, economic indicators continue to
21 identify growth opportunities in our service territory and
22 have led to a forecasted average 1.3% growth projection over
23 a ten year period versus the 0.6% projected in our last rate

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1 case in 2009. This anticipated customer demand is not only
2 driving the need for transmission and substation
3 infrastructure but it is also requires expansions to the
4 local distribution system to connect these new or additional
5 loads. Con Edison's Electric Operations Organization will
6 address this anticipated load growth on the distribution
7 system by installing, reinforcing, and upgrading, as
8 necessary, primary network feeder cables, network
9 transformers, underground secondary cable, non-network
10 primary and secondary cables and wires, non-network
11 transformers, and underground and overhead services. Also,
12 we will transfer load between networks in the distribution
13 system to relieve potential overloads at area substations
14 when adequate capacity is available at neighboring area
15 substations and it is economically feasible.

16 Q. Please describe the Electric Distribution capital programs
17 and projects listed in Exhibit __ (IIP-3) under "New
18 Business."

19 A. These programs and projects are intended to address
20 increased demand on our distribution system due to the
21 addition of new customers. The "white papers" under the
22 category "New Business" in Exhibit __ (IIP-3) describe the

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1 Electric Operations capital programs that support the
2 addition of new customers onto our system.

3 Q. Please discuss the New Business Capital program in the "New
4 Business" category?

5 A. The **New Business Capital** program consists of projects that
6 connect new customer load to the distribution system
7 including the installation of electric revenue meters.
8 While permit trends are expected to slowly rise in 2013 and
9 beyond, and we continue to see growth opportunities in our
10 service territory. In the current 5-year time frame (2013-
11 2017), business entities remain engaged in building various
12 projects, some of which include:

13 **Transit** - MTA Station and traction load for the #7 Line
14 extension and the Fulton Street Transit Hub.

15 **Developments Over Rail Yards** - Atlantic Yards (Forest City
16 Ratner) and Hudson Rail Yards (Related Companies/Oxford
17 Properties Group)

18 **Commercial and Residential** - Various residential projects
19 including Hunters Point and Queens West, Gotham West
20 Development and the Carnegie 57 Condos. Continuing World
21 Trade Center rebuild activities, property developments at
22 the Whitney Museum, Hunts Point produce market, and the

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1 Varick Street data center project are all on the near-term
2 horizon.

3 **Schools** – New York City’s School Construction Authority’s
4 \$9.3 billion budget, which covers work through 2014,
5 supports 26 fewer schools than originally forecasted in
6 2010. However, several college-level projects including
7 Manhattanville-Columbia, Roosevelt Island South and Bronx
8 Community are slated for completion over the next few years.

9 **City Development Projects** – Projects expected to move
10 forward include College Point Police Academy Training
11 Facility, Willets Point Development, Coney Island
12 Revitalization, the PSAC II 911 call center, and the
13 Brooklyn Cruise Terminal/Shore Power Project.

14 These projects are representative of the numerous
15 development opportunities planned and underway in our
16 service territory. As we analyze the distribution system to
17 connect these new loads, we determine that in many cases the
18 existing system is at or beyond its capability and the
19 addition of this load can no longer be served by extending a
20 service lateral from our distribution system. More
21 specifically, many of these residential and commercial
22 projects require extensive infrastructure, such as,
23 secondary main reinforcement, primary feeder extensions and

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1 transformer vault installations to adequately support these
2 new/additional loads. Capital expenditures for New Business
3 are projected to be \$155 million in 2013, \$160 million in
4 2014 and \$160 million in 2015.

5 Q. Please describe the Meter Installation program.

6 A. The **Meter Installation** program provides for the installation
7 of electric revenue meters throughout the Company's service
8 territory associated with new business customers.

9 Installation of electric meters provides an accurate means
10 to record customer energy usage for revenue collection.
11 Capital expenditures for Meter Installation are projected to
12 be \$17.4 million in 2013, \$16.8 million in 2014 and \$15.1
13 million in 2015.

14 Q. Please describe the Electric Operations capital programs and
15 projects listed in Exhibit __ (IIP-3) under "System
16 Expansion."

17 A. These programs are intended to address increased demand on
18 our distribution system due to increased customer
19 consumption of electricity. These programs minimize the
20 risk of our equipment operating above its design limits as a
21 result of the increased electric requirements associated
22 with economic growth. The "white papers" describing each of

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1 the Electric Operations capital programs and projects that
2 support System Expansion are provided in that exhibit.

3 Q. Please discuss the specific Electric Operations projects in
4 the "System Expansion" category?

5 A. The specific projects are as follows:

6 **Pennsylvania/Waterside** - This project is to establish a
7 network split by transferring 74MW from the Pennsylvania
8 Network fed by the West 42nd Street No. 1 Substation to
9 create a new Waterside Network fed by the West 42nd Street
10 No. 2 Substation. Capital expenditures for this project are
11 projected to be \$3.0 million in 2014 and \$6.0 million in
12 2015.

13 The purpose of the **59th Street Bridge Crossing** project is to
14 replace six primary distribution feeders that are routed
15 over the 59th Street Bridge (Queensborough Bridge) that
16 supply Roosevelt Island. This project will also provide
17 spare capability to add additional feeders for future
18 growth. Part of the capability provided by these
19 distribution feeders will support the Cornell-NYC Tech
20 Applied Sciences facility on Roosevelt Island currently
21 under development. The existing feeders consist of aerial
22 cables that are hung on messengers on the outer roadways of
23 the bridge. Since 2004, there have been 10 failures and

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1 emergency repairs of the feeders. The replacement project
2 will include a new conduit system which will provide
3 additional protection for the feeder cable to mitigate
4 failures. The new system will be more serviceable than the
5 existing system, and will enable quicker restoration of
6 these feeders in the event of a failure. This project will
7 also provide spare capability to add additional feeders for
8 future growth. The Company is conducting a study in 2012
9 to select the best method of installing review viable
10 alternatives to install a new conduit system either over
11 the span of the bridge or hung under the roadway. A total
12 of four new systems, each consisting of four 5" steel
13 conduits, are currently being explored. The projected
14 expenditures - \$2 million in 2013 and \$1 million in 2014 -
15 reflect the estimated cost of a like-and-kind replacement
16 and may change as the engineering scope is better defined.

17 **Cable Crossing** - This program is seeking funding for the
18 reinforcement of primary cable crossings in the Flushing
19 and Riverdale networks. The following projects are part of
20 this program.

- 21 • City Island 4 kV feeders 7207 and 5361

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- 1 o Replace 4kV feeders 7207 and 5361 that supply
2 service to City Island and provide conduits for
3 spare cable crossings.
- 4 • Riverdale Network River Crossings
 - 5 o Perform the engineering study required to replace
6 the remaining two river crossings for the feeders
7 that supply the Riverdale Network. Engage the
8 services of a reputable engineering design company
9 to provide detailed designs and obtain all
10 environment approvals necessary to construct two new
11 river crossings.
- 12 • Flushing Network & Paerdegat Basin
 - 13 o The Corona # 1 substation supplies the Flushing
14 Network (7Q) grid. The load pocket is located 2
15 miles from the substation and the feeders must
16 transverse through geographical obstructions. Four
17 of the crossings must go over or under the Grand
18 Central Parkway, and 4 other crossing are routed
19 through the waterway (the Flushing River). With
20 load forecasted to increase in the Flushing Network,
21 feeders are at or nearing their capacity. For this
22 crossing, we will double the number of ducts to 16.

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1 Five inch conduit systems will be built to
2 accommodate higher rating cable for all these jobs.

- 3 o There are three feeders (2 - 27kV and 1 - 4kV) in
4 Brooklyn that cross the Paerdegat Basin via
5 submarine cable. There is no way to replace this
6 cable if it fails. To resolve this issue, these 3
7 feeders will be rerouted around the Paerdegat Basin
8 through an overhead system.

- 9 • Roosevelt Avenue & Grand Central Parkway

- 10 o This crossing has two systems. Both the Northerly
11 System and the Southerly System have 4 feeders each.
12 This crossing requires immediate attention because
13 of the projected overloads on the feeders and
14 presence of korduct and transite ducting. There are
15 spares in only one section of the crossing so there
16 is no other design alternative to alleviate the
17 feeder overloads, without overloading other feeders.
18 This job entails installing approximately 1455 ft of
19 conduit under the overpass. The asbestos abatement
20 has not been addressed in the estimate. This
21 crossing remains in negotiation with NY State DOT in
22 order to secure permission to proceed.

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- 1 • Horace Harding Expressway and the College Point Boulevard
 - 2 o The current duct system consists of one M11-6 M12766
 - 3 connected by 4-4" 591'FF to a second M11-6 M12588.
 - 4 To increase system reliability and future capacity,
 - 5 an additional four 5" ducts will be installed via
 - 6 the same manholes to bring the total number of ducts
 - 7 to 8 with 4 as emergency spares. This will involve
 - 8 901' of conduit, with 603' to cross College Pt Blvd.

- 9 • Paerdegat Basin Crossing
 - 10 o Reroute two 27kV feeders (4B14, 4B16) and one 4kV
 - 11 feeder (3018) around Paerdegat Basin from
 - 12 Bensonhurst No. 2 Area substation. The reroute will
 - 13 require the construction of new overhead system
 - 14 involving replacement of about 60 existing poles,
 - 15 constructing 6 new risers and running 460 spans of
 - 16 27kV and 250 spans of 4kV aerial cable around the
 - 17 basin.

18 Capital expenditures for this program are projected to be
19 \$2.9 million in 2013, and \$3 million per year in 2014 and
20 2015.

21 Q. Please continue with your description of projects in the
22 "System Expansion" category.

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1 A. The following programs are designed to minimize the risk of
2 our equipment operating above design as a result of the
3 increased electric requirements associated with customer
4 demand:

5 **Primary Feeder Relief** - The Company will reinforce all
6 network distribution feeders that are projected to operate
7 above 100 percent of their thermal ratings, for both normal
8 (all equipment in service) and contingency (any two feeders
9 out of service) design conditions during summer peak load
10 periods. Reinforcement projects may include cable section
11 replacement, transferring load between feeders, balancing
12 load on a given feeder, bifurcating an existing feeder, and
13 establishing new feeders.

14 Enhancement of the software used for rating feeders has
15 dramatically reduced the volume of relief work by improving
16 the accuracy by which we model the thermal characteristics
17 of the environment in which the feeders operate. Capital
18 expenditures for this ongoing program are projected to be
19 \$6.9 million in 2013, \$10.5 million in 2014, and \$9.7
20 million in 2015.

21 **Network Transformer Relief** - Relieving network transformers
22 that are projected to operate beyond their normal or
23 contingency ratings will improve both network reliability

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1 and extend the service life of the equipment. Relief
2 projects include replacing the overloaded transformer with a
3 new transformer that has a higher rating, a larger
4 transformer with a greater capacity, or introducing a new
5 transformer to the system with associated secondary
6 reinforcement which will diversify the area load to
7 effectively lower the loads of all the nearby transformers.
8 The costs include the installation of new cable, conduit and
9 vaults. The program will address projected overloaded
10 transformers using a prioritization process that considers
11 such factors as transformer type, vintage and operating
12 conditions. Capital expenditures for this ongoing program
13 are projected to be \$22.5 million in 2013, \$29.5 million in
14 2014, and \$27.3 million in 2015.

15 **Non Network Feeder Relief (Open Wire)** - This program
16 provides for the reinforcement of open-wire and underground
17 cable on non-network system feeders that are projected to
18 operate above 100% of their normal or emergency rating. This
19 program involves replacement of overhead feeder wire, poles,
20 risers, underground cable, and associated equipment. Relief
21 projects include replacing overloaded cable with higher
22 rated cable, transferring loads from one feeder to another
23 feeder, and establishing new feeders. The program will

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1 address the projected overloads using a prioritization
2 process that considers factors such as degree of overload,
3 system design and potential reliability improvement. The
4 Company's goal is to relieve identified feeder overloads
5 prior to the summer. Capital expenditures for this ongoing
6 program are projected to be \$6.7 million in 2013, \$6.5
7 million in 2014, and \$6.0 million in 2015.

8 **Overhead Transformer Relief** - This program inspects, and
9 replaces overhead transformers that are overloaded and have
10 the greatest potential to trip during a summer heat event.
11 Capital expenditures for this ongoing program are projected
12 to be \$1.9 million in 2013, \$1.9 million in 2014, and \$1.8
13 million in 2015.

14 **Unit Substation Load Relief** - The Grant City #2 Unit
15 Substation (USS) is located in the Staten Island Service
16 Area and is part of the Fox Hills 4kV non-network load
17 area. The station, which consists of a 10.5 MVA
18 transformer, a 1,200 amp breaker and 4kV bus, is fed from
19 one of several 33kV feeders supplying its 4kV grid.
20 The emergency load relief plan for summer 2013 indicates
21 that upon the loss of another 33kV feeder supplying the 4kV
22 grid, the loading on Grant City #2 will be 113% of its
23 emergency rating, with the limiting factor being the 1,200

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1 amp rated bank breaker and 4kV bus. This single
2 contingency would require the de-loading of the Grant City
3 #2 USS, creating a radial feeder, reducing system
4 reliability, and increasing the risk of power outages.
5 This project will replace the existing 1,200 amp rated bank
6 breaker and 4kV bus with a 2,000 amp breaker and bus at the
7 Grant City #2 USS. The alternative to this project would
8 be to de-load the USS by installing a 4kV mini loop, which
9 would be a much more costly alternative. The projected
10 capital cost for this program is \$0.2 million in 2013.

11 Q. Does this conclude your testimony regarding projects and
12 programs under the category of "Electric Distribution – New
13 Business/System Expansion?"

14 A. Yes, it does. Now the Panel would like to discuss the
15 Company's reliability programs and projects.

16 **VII. Reliability Capital and O&M Expenditure Requirements**

17
18 Q. Please describe the reliability of electric service in Con
19 Edison's service area.

20 A. Con Edison has consistently been recognized as operating one
21 of the most reliable electric systems in the United States.
22 In 2009, our overall reliability was 147 customer
23 interruptions per 1,000 customers. In 2010, it was 129

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1 customer interruptions per 1,000 customers. In 2011, it was
2 104 customer interruptions per 1,000 customers. The
3 industry average is about 1,250 customer interruptions per
4 1,000 customers. A national survey comparing investor-owned
5 utilities ranked Con Edison's reliability as seven times
6 better than the industry average.

7 Q. I show you a document titled, "Service Reliability (2011),"
8 and ask whether that document was prepared under your
9 direction?

10 A. Yes, it was.

11 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-5)**

12 Q. Please describe what is shown on Exhibit __ (IIP-5).

13 A. Exhibit __ (IIP-5) depicts the national and New York State
14 customer interruption rate compared with the interruption
15 rate on Con Edison's system. As shown on the exhibit, a Con
16 Edison network customer experiences an outage approximately
17 50 times less often than the average customer in the United
18 States.

19 Q. What is the overall purpose of the Company's Reliability
20 programs and projects?

21 A. Con Edison's Reliability programs and projects are designed
22 to maintain the reliability and safety of the Company's
23 transmission and distribution infrastructure both in the

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1 near and long term while minimizing risk and the impact of
2 our infrastructure requirements on customer's bills. Con
3 Edison has always placed significant emphasis on maintaining
4 a very high level of reliability. Our customers expect
5 continuous, reliable electric service at work and at home.
6 While reliability and safety remain critical factors when
7 determining how we conduct business, the Company also
8 recognizes the need to consider cost and to prioritize
9 reliability work to invest reliability funding as effectively
10 as possible. All of the Company's reliability programs and
11 projects are intended to maintain the operational capability,
12 reliability and safety of the transmission, substation, and
13 distribution systems. A secondary goal of the Company's
14 reliability programs is to address near-term reliability
15 issues that have been identified and exist across all
16 networks (such as poor performing components like stop
17 joints). Finally, the Company works to programmatically
18 and continuously upgrade and replace system components
19 before they become degraded or obsolete and are no longer
20 supported by manufacturers with spare parts and technical
21 support. As we will discuss later in this testimony, the
22 Company is proposing modifying some of these programmatic

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1 approaches to better focus our capital on higher priority
2 work.

3 Q. Please provide an overview of recent efforts to enhance the
4 safety of the electric system.

5 A. Con Edison strives to maintain the safety of both the
6 public and our employees. Safety is always a paramount
7 consideration in each and every task. The Company has
8 undertaken unprecedented steps to improve the safety of our
9 electric system. Stray voltage detection, transformer
10 failure prevention, and underground structure event
11 prevention are the Company's highest priority public safety
12 concerns. The Company has implemented targeted programs
13 that address these priorities and help mitigate the public
14 safety risk.

15 Major programs undertaken to mitigate electric shock
16 hazard from stray voltage include mobile stray voltage
17 testing, underground and overhead equipment inspection
18 programs, and non-conductive composite cover installation.
19 Major programs to prevent transformer failures include: the
20 vault cleaning program, tank rupture mitigation program,
21 anode installation program, the dissolved gas analysis
22 program, and the pressure, temperature and oil sensor
23 installation program. Major programs to mitigate

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1 underground structure events include the vented manhole and
2 service box cover project. The Company has developed and
3 implemented advanced technologies used in these programs,
4 such as the mobile stray voltage detection and composite
5 covers. The Company is committed to improving public
6 safety and is working on various research initiatives with
7 EPRI, GE, University of Connecticut, Texas A&M University,
8 and Columbia University to develop solutions that address
9 these concerns.

10 The Company has achieved significant milestones in
11 improving public safety over the last five years. The
12 number of electric shocks that were caused by Company
13 equipment has been reduced by 43%, the number of
14 transformer failures has been reduced by 60%, and the
15 number of significant underground structure (manhole fires
16 and explosions) events has been reduced by 20%.

17 Q. I show you a document titled, "Electric T&D - Reliability"
18 and ask whether that document was prepared under your
19 direction?

20 A. Yes, it was.

21 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-6)**

22 Q. Please describe what is shown on Exhibit __ (IIP-6).

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1 A. Exhibit __ (IIP-6) lists the capital program and project
2 funding requirements that support Reliability work
3 conducted by System and Transmission Operations (S&T0),
4 Substation Operations (Transmission and Area Substations),
5 and Electric Operations (Distribution System) for the years
6 2013 through 2017. The exhibit also provides five year
7 historic spending for 2007-2011 and a 2012 end of year
8 projection for Reliability programs and projects. The
9 exhibit presents O&M program changes for Reliability. The
10 exhibit also contains "white papers" for each capital
11 program and project that provide more detailed information
12 such as: program and project work description,
13 justification, alternatives, estimated completion date,
14 current status, and forecasted funding.

15 **A. Substation Operations Reliability**

16 **1. Substation Operations Capital Reliability Programs and**
17 **Projects**

18 Q. Please provide an overview of the Company's Substation
19 Operations capital programs and projects shown under the
20 "Reliability" category.

21 A. There are currently 39 transmission stations and 62 area
22 substations located throughout Con Edison's electric
23 service territory. Most of these stations are over 40

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1 years old. The funding for substation reliability work
2 provides for the replacement and/or upgrade of major
3 components such as transformers, circuit breakers,
4 disconnect switches and circuit switchers, protective relay
5 equipment, communication equipment, battery systems, and
6 miscellaneous equipment such as potential/current
7 transformers, insulators, surge arresters and wiring. The
8 goal is to programmatically upgrade and replace these major
9 components before they become degraded and failure prone.
10 The integrity of the physical structures (substation
11 buildings, relay houses/cabinets, and switchgear houses)
12 that house the electrical components of a substation is
13 also important to system reliability.

14 Q. Please discuss the Substation Operations "Reliability"
15 programs on Exhibit __ (IIP-6).

16 A. **Elmsford - Upgrade Elmsford Substation.** The Elmsford
17 substation, located in Westchester County, is over 50 years
18 old, and was substantially refurbished, with a new
19 switchgear section that went into service in 2012. While
20 the vast majority of the work for this refurbishment
21 project has been completed, improving the drainage system
22 in several areas of the station remains to be completed.
23 Capital expenditures to complete this work are projected to

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1 be \$1 million in 2013.

2 Q. Please discuss the other Substation Operations Reliability
3 programs on Exhibit __ (IIP-6) beginning with the programs
4 to replace or overhaul circuit breakers.

5 A. A major component of both transmission stations and area
6 substations are circuit breakers. Circuit breakers are
7 used to stop the flow of current during both normal and
8 emergency conditions. Under normal conditions, they are
9 used to isolate equipment for maintenance, replacement and
10 load transfer. During emergency conditions, circuit
11 breakers are triggered by protective relay systems to
12 automatically isolate faulted equipment. We are continuing
13 our program to replace the older or more problematic
14 circuit breakers in each of the voltage classifications.
15 The **Replace/Retrofit Over-dutied 13/27 kV Circuit Breakers**
16 program provides funding to replace a number of existing
17 13, and 27, and 33kV circuit breakers installed in our
18 substations. Historically, this program focused only on
19 those units that currently are not rated to interrupt
20 maximum fault currents under worst-case scenario fault
21 conditions. Since 2003, Con Edison has been required by a
22 Reliability Performance Mechanism to perform retrofits of
23 over-duty 13kV and 27kV breakers at a rate of at least 60

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1 units per year, subject to revenue adjustment of \$100,000
2 per breaker less than the minimum. While the replacement
3 of 60 breakers annually is fully consistent with the goals
4 of the Company's program, the performance mechanism reduces
5 the Company's flexibility in considering other criteria
6 beyond over-dutied condition in implementing this program.
7 Thus, without a rigid-end-of-the-year target, the Company
8 might be able to implement removals with a better focus on
9 factors such as degree of over-duty, whether the retrofit
10 process has been initiated in a station, breaker age and
11 obsolescence status, maintenance requirements and failure
12 history, degree of over-duty, and interrupting technology.
13 Later in our testimony, we propose that this performance
14 mechanism be ended.

15 The unit cost for a 13kV circuit breaker retrofit is
16 approximately \$126,000 and the unit cost for a 27kV and
17 33kV circuit breaker is approximately \$240,000. We expect
18 to continue to replace 60-70 breakers per year under this
19 program, as we have done in the past. Capital
20 expenditures are projected to be \$10.28 million in 2013,
21 \$11.3 million in 2014, \$10.5 million in 2015, and \$10
22 million annually in 2016 and 2017. We will discuss this

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1 program further when we address the Company's Reliability
2 Performance Mechanism

3 Q. Please discuss the **Breaker Capital Upgrade Program** shown in
4 Exhibit ____ (IIP-6).

5 A. In 2013, we will begin a High Voltage Circuit Breaker
6 Capital Upgrade Program. This program combines and
7 replaces the two individual programs to replace or upgrade
8 138kV and 345kV circuit breakers that had existed through
9 2012. The work scope includes the replacement or capital
10 upgrade of breakers based on their performance in
11 accordance with guidelines established in our maintenance
12 specification CE-ES-1000. These breakers will be targeted
13 for replacement when major maintenance is required in
14 accordance with the EPRI maintenance ranking program and
15 subsequent Peer team review as directed by CE-ES-1000.
16 Replacement is performed when a breaker or breaker type is
17 deemed to be in poor performing condition due to
18 progressive deterioration, lack of spare parts, high
19 maintenance costs, oil and/or gas leakage, and/or poor
20 performance history.

21 Replacement is also performed when determined to be
22 more economical than overhaul, a decision that also results
23 in enhanced reliability. The Westinghouse 1380SF6 138kV

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breakers have been targeted for replacement due to performance, including SF6 leakage, in-service failures, and maintainability issues. Oil-filled breakers are also targeted for replacement based on performance, environmental concerns, risk of major substation events, inability to obtain parts, and the high cost to maintain these 50-60 year old vintage breakers. 345kV SFA breakers have also been targeted for replacement due to SF6 leakage concerns.

Each breaker replacement will be reviewed individually to establish the business case for its replacement. If the replacement costs are too high or if other factors determine that the replacement is not justified, then other maintenance plans (overhauls) may be enacted.

The replacement of deteriorated or problematic circuit breakers provides system enhancement through better reliability. The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system. Failure to do so can have serious system consequences and affect customer service reliability. The proper isolation of system disturbances is also critical in maintaining a safe working environment for station personnel as well as safety for the

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1 public. The replacement of deteriorated or problematic
2 circuit breakers is cost effective versus the alternative
3 of frequent repairs. In addition, this program will reduce
4 future maintenance costs such as special custom fabrication
5 of unavailable replacement parts and expensive SF6 gas
6 replenishment. This program has been a significant driver
7 in the reduction of operation and maintenance costs, SF6
8 emissions, and forced outages. In the last few years, we
9 have seen a dramatic decrease of over 50% in the labor
10 hours for corrective maintenance on high voltage breakers.
11 Significant reductions in SF6 emissions have also been
12 realized during this same time frame.

13 Capital expenditures for this program are projected to
14 be \$5.2 million in 2013 and then \$9.5 million annually for
15 2014-2017, to typically support approximately 8-12 breaker
16 replacements/year at an average cost of \$800,000/breaker.

17 Q. Please describe the Company's disconnect switch replacement
18 program shown on Exhibit __ (IIP-6).

19 A. The **Disconnect Switch** replacement program enhances the
20 reliability of the system by proactively addressing
21 disconnect switch performance issues. As disconnect
22 switches age and degrade, the probability of malfunction
23 increases. Replacing the units on an emergency basis

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rather than on a scheduled basis increases the replacement cost and impacts reliability. For disconnect switches that have reached the end of their useful life, where replacement parts are no longer available or require special custom order with long lead times, the potential for extended repair outages exists. This on-going program replaces or performs a capital retrofit/overhaul on disconnect switches found to be frequently unreliable, and/or approaching the end of their useful life.

Disconnect switches are not replaced or retrofit/overhauled on a time-based frequency. The entire population is reviewed on a periodic basis by Substation Operations and Engineering and candidate disconnect switches are chosen based on such factors as criticality of application, prior maintenance history, safety concerns, outage availability, and end of useful life issues.

Substation Operations and Engineering determine whether a retrofit, overhaul, or replacement is needed. Some of the factors used to determine if a replacement is necessary include the condition of the grounding blade, motor operator, operating linkage, and the porcelain insulator. A disconnect switch retrofit consists of the replacement of all current carrying components including

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1 the jaws and blade, and an overhaul replaces only the
2 blades and jaws.

3 Funding has been allocated to address growing age and
4 end of useful life issues related to the disconnect switch
5 population identified during our periodic reviews. Capital
6 expenditures for this program are projected to be
7 approximately \$3 million annually for 2013-2015, and \$3.3
8 million annually for 2016-2017.

9 Q. Please describe the Circuit Switcher Replacement Program.

10 A. The **Circuit Switcher Replacement Program** replaces circuit
11 switchers that could compromise the reliability of the
12 associated equipment and consequently, the system as a
13 whole. We have identified four S&C Mark 2 and the S&C type
14 G circuit switchers on our system where maintenance
15 activities have become increasingly more challenging. The
16 S&C Mark 2 and the S&C type G are no longer supported by
17 the manufacturer with parts or service. This program will
18 replace one (1) circuit switcher per year with reliable
19 upgraded models at a unit cost of \$1 million per circuit
20 switcher. As this program proceeds, additional circuit
21 switcher makes/models may be identified as challenges to
22 maintenance effectiveness, and they will be included in
23 this program for future years. Capital expenditures for

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1 this program are projected to be \$1 million in 2014-2015,
2 and \$1.1 million in 2016.

3 Q. What is the purpose of the Condition Based Monitoring
4 Equipment Program identified on Exhibit __ (IIP-6)?

5 A. The purpose of the **Condition Based Monitoring Equipment**
6 program is to install condition based monitoring equipment
7 on power transformers to identify and respond to equipment
8 problems prior to failure thereby improving transformer
9 reliability. This system enhancement program improves our
10 ability to closely monitor the condition of our critical
11 power transformers and hence better schedule our
12 maintenance activities. The main drivers of this program
13 are maintenance optimization through the integration of
14 condition monitoring and reliability improvements realized
15 by the reduction of unanticipated transformer failures.
16 Condition monitoring is also used to circumvent time-based
17 maintenance thereby improving transformer availability and
18 reducing overall maintenance costs. The equipment
19 presently included in the program is Load Tap Changer (LTC)
20 monitoring equipment and on-line DGOA units. Capital
21 expenditures for this program are projected to be \$250,000
22 annually for 2013-2015, and \$300,000 in 2016-2017.

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1 Q. Please describe the Company's Substation Transformer
2 Replacement program.

3 A. The **Substation Transformer Replacement** Program replaces
4 transformers that have reached the end of their life
5 expectancy and cannot be maintained in a reliable operating
6 condition. Units are targeted for replacement based on
7 their operating conditions and higher risk of failure.
8 Also included in the scope of the transformer replacement
9 is the installation of a moat system for the vault, a new
10 fire protection system, and a transformer condition
11 monitoring system. Funding will also be used to secure
12 transformer orders with long lead times for future
13 replacements identified by our asset management program.

14 There are approximately 400 transformers on the system
15 of which approximately 150 are over 40 years old. As these
16 units approach the end of their life cycle, the amount of
17 corrective maintenance and the probability of malfunction
18 increase. Replacement parts are special custom order and
19 require long lead times to receive. Proactively replacing
20 problematic transformers prior to failure is cost effective
21 when compared to emergency replacement, improves the
22 reliability of the system, and provides a process for life
23 renewal of the transformer fleet.

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1 Q. What is the current status of the program?

2 A. In 2012, we completed the replacement of Washington Street
3 Tr. # 2, and expect to begin the replacement of Dunwoodie
4 PAR N1. Our plans for subsequent years are as follows:

5 2013 Planned Work

- 6 • Dunwoodie PAR N1 – Complete Replacement
- 7 • Dunwoodie – PAR S1 and S2 - Begin Replacement
- 8 • Avenue A Tr. # 3 – Begin replacement

9 2014 Planned Work

- 10 • Dunwoodie PAR S1/S2 Complete Replacement
- 11 • Avenue A Tr. #3 – Complete Installation
- 12 • Avenue A Tr. #1 – Begin Installation
- 13 • Cherry Street Tr. #1- Begin Replacement

14 2015 Planned Work

- 15 • E179th Street – Replace TR #6 - Begin Installation
- 16 • Avenue A - Tr. #1 Complete Installation
- 17 • Cherry Street Tr. # Complete Replacement
- 18 • East 13th Street Tr. #11- Begin Installation

19 2016 Planned Work

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- 1 • East 179th Street Tr. #6 – Complete Installation
- 2 • East 13th Street Tr. #11 – Complete Installation
- 3 • East 179th Street Tr. #5 – Begin Installation

4 The actual replacement schedule may be modified based upon
5 criticality of each unit as determined by data from
6 monitoring programs. The projected capital expenditures
7 for the program vary slightly from year to year for 2013-
8 2017, but averages \$24.5 million annually.

9 Q. Please describe the Company's relay protection systems
10 programs, shown in the "Reliability" section of Exhibit ____
11 (IIP-6).

12 A. The protective equipment (relays) and associated
13 communication lines are the brain and nerve systems of our
14 transmission/substation grid. The relays detect system
15 disturbances and direct circuit breakers, whether at the
16 local substation or a remote substation, to immediately
17 isolate faulted equipment. Three distinct programs have
18 been developed to address obsolete and problematic
19 components of this system and add additional functionality:
20 **Relay Modification Program** - This multi-year program
21 provides for technology upgrades to identified relay
22 protection systems at various substations. This ongoing

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1 program upgrades relay protection equipment to modern
2 state-of-the-art standards, prevents incorrect automatic
3 relay operations thereby improving reliability, and
4 provides better analysis capabilities. The projected costs
5 for the Relay Modification Program vary slightly from year
6 to year, but are estimated at approximately \$8.67 million
7 annually from 2013-2017. The specific project details are
8 presented in Exhibit __ (IIP-6).

9 **Control Cable Upgrade** - Substation control cables are
10 essential for the safe and reliable operation. These
11 cables are used to send high-speed fault clearing trip
12 signals to protective relays and equipment status to SCADA
13 systems. AC and DC control cables for outdoor substations
14 are routed in covered troughs and ducts and in some cases,
15 conduit. Many of our stations are more than 40 years old
16 and due to exposure to the elements, some of these cables
17 have deteriorated and are failing. This multi-year program
18 provides funding for the systematic replacement of the
19 older cables, conduits and junction boxes, and modification
20 of trough and duct systems to accommodate the new cables.
21 These improvements will reduce inadvertent trips of
22 electrical equipment at substations. The work is performed
23 on a priority basis based on the condition of the cable and

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1 the outage availability of impacted equipment. The
2 projected capital expenditures for the program are \$1
3 million annually in 2014-2015, and \$1.1 million annually in
4 2016-2017.

5 Q. Are there any other major substation components
6 replacements that you would like to discuss?

7 A. Yes. Substation equipment requires monitoring (alarm
8 panels and substation automation), testing (high voltage
9 test sets and ground and test devices), back-up power in
10 the event of loss of off-site power (batteries), as well as
11 the ability to be operated remotely (remote terminal unit).
12 **Category Alarms** - In most instances, alarm equipment was
13 placed in service as part of the station commissioning.
14 Therefore, our alarm equipment has been in service for an
15 average of 40 years. Due to lack of spare parts and/or
16 vendor support of system modifications, the Company has
17 been replacing high-maintenance units since the late 1990s.
18 Since more panels are becoming obsolete, the Company is
19 proposing to accelerate the replacement of these panels.
20 This enhancement will improve the operational response to
21 substation alarms. The program consists of replacing the
22 present substation failing electro-mechanical and solid-
23 state-based alarm systems with a standardized programmable

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1 PLC/PC type alarm annunciator, comprising of a PLC - logic
2 processing unit ("LPU"), Remote I/O units (where needed),
3 and redundant set of HMIs. It provides local alarm
4 functionality to the station operators and sends category
5 alarms to EMS at ECC/AECC. The projected capital
6 expenditures for this program are \$1.5 million annually in
7 2013, 2014, and 2015.

8 **High Voltage Test Set Program** - This program provides
9 funding for three different types of test sets that are
10 required at our facilities:

11 High voltage DC test Sets - Substation Operations uses DC
12 test sets for distribution feeder processing. Various test
13 sets are over 20 years old and require constant repair. The
14 replacement program systematically replaces existing test
15 sets based on age, corrective maintenance, and availability
16 of parts. This program will purchase and replace on
17 average three DC test sets per year.

18 AC Very Low Frequency (VLF) Test Sets - These test sets are
19 used to perform on-site AC hi-pot testing and diagnostics
20 of 4, 13, 27, and 33 kV medium-voltage EPR and Poly cable
21 feeder cables. There are six mobile and 20 permanently
22 installed AC VLF test sets for distribution feeder
23 processing on the Con Edison system. This program will fund

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1 the purchase and installation of, on average, 3 to 5 AC VLF
2 test sets per year to expand the number of AC hi-pots
3 performed on distribution feeders.

4 We are also working to develop a dual function test set
5 that will give us the capability to perform AC hi-pots and
6 fault conditioning in one unit. These units would allow us
7 to perform all feeder processing activities with a single
8 test set. Currently, we need to use DC test sets to
9 condition feeder faults in order to locate them
10 expeditiously, since existing AC test sets cannot perform
11 this function. We are currently working to develop a
12 prototype combination set and expect to have one in place
13 by 2014. If this prototype is successful, we will phase
14 out purchase of single mode units and start purchasing only
15 combination sets.

16 AC Test Sets, 345 kV - The W49th St. Substation test set,
17 which has been in service for over 30 years, is no longer
18 supported by the manufacturer. This set is needed to
19 perform conditioning and proof tests of equipment after
20 overhauls and repairs. Replacement of this unit will
21 eliminate the need to rent units when required, which is
22 not preferred due to cost and vendor availability
23 constraints. This program will fund the purchase of a new

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1 345 kV transmission voltage AC test sets for the W49th St.
2 substation. It is currently on order and planned to be
3 delivered in early 2013.

4 The projected capital expenditures for this program
5 are \$5 million annually for 2013-2017. The specific
6 program details are presented in Exhibit __ (IIP-6).

7 **DC System Upgrade Program (Batteries)** - This program
8 replaces the DC system batteries and upgrades DC system
9 equipment such as load boards, rectifiers, and the
10 associated cables and conduits. Batteries are an essential
11 component for the safe and reliable operation of
12 substations. Batteries provide adequate and uninterrupted
13 supply of current for control functions, indications,
14 protective relaying and emergency light and power. To
15 maintain continuous charge, substation batteries are
16 connected to rectifiers and are periodically inspected for
17 proper operation. As more electronic equipment is added to
18 the substation, additional battery power is required. Load
19 studies are performed at each station to determine if the
20 125 volt DC battery systems can support the station load in
21 the event of loss of offsite power. Based upon the
22 individual analyses, batteries and associated conduit,
23 cable, and load boards are replaced either due to load or

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1 because they have reached the end of their life cycle (12
2 to 15 years for batteries). The projected capital
3 expenditures for this program vary slightly year to year,
4 but average \$3.47 million annually for 2013-2017.

5 Q. Are there any other substations that will require
6 significant reliability upgrades?

7 A. Yes. **The East River Station Upgrade** project is currently
8 in progress and involves the purchase and installation of a
9 new microprocessor based automation system at the East
10 River 69kV Transmission Substation. The new system will
11 perform operating, protective, and monitoring functions for
12 the 69kV circuit breakers, transformers, phase angle
13 regulators, feeders, and buses, as well as several 138 kV
14 circuit breakers at East 13th Street. This system will
15 include approximately 100 new protective relay panels, a
16 new operating console with monitors, control and
17 supervisory equipment, and all associated peripheral and
18 support systems including batteries, chargers, local-remote
19 communications and station security. The new components
20 are being installed in the recently completed control room
21 in the 69kV yard at East River, thereby completing
22 relocation of all operating, protective, and monitoring
23 functions from the 8th floor of the East River generating

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1 station. The project will retire in place the existing
2 operating, control, and protective systems and devices,
3 currently located in the generating station control room,
4 terminal board room, and various relay rooms.

5 The benefits of this project are multiple. This
6 project will enhance system performance, improve operator
7 response time and upgrade the protection and control
8 systems, thereby enhancing reliability of the outlet for
9 East River Gen. No. 1 and the power supply to the Leonard
10 Street substation supplying the Greenwich, Sheridan, Canal,
11 and Park Place networks. This project's estimated
12 completion date is 2015. The projected capital
13 expenditures for this project are \$6 million in 2013, \$5
14 million in 2014, and \$6 million in 2015.

15 Q. Please describe the Area Substation Reliability Program.

16 A. **Area Substation Reliability Program and Auto Ground**

17 **Switches:** Following the August 3, 1990 Seaport area
18 substation fire, Con Edison committed in 1991 to modify
19 substation designs to provide more reliable high speed
20 clearing of transformer secondary faults and reduce the
21 possibility of loss of the area substation during a
22 protracted fault incident. This program provides for the
23 installation of two independent lines of protracted fault

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1 protection with electrical and physical separation for the
2 area station transformers. The first line of protection is
3 provided by the installation of a circuit switcher, which
4 is tripped by normal primary protection, and the second
5 line of protection is provided by an interrupter, which is
6 tripped by a separate and independent back-up protracted
7 fault protection system located in the transformer vault.
8 If space is limited, then the second line of protection can
9 be provided by a transfer trip relay scheme.

10 The Auto Ground Switch ("AGS") retirement program has
11 been combined with this reliability program because the AGS
12 can only be retired when either a circuit switcher or
13 transfer trip relay scheme is installed. Where feasible
14 the retirement of the AGS will be performed simultaneously.

15 Q. Has there been a change in how Con Edison proposes to
16 pursue this program?

17 A. Yes. To date we have been able to incorporate the modified
18 substation design in substations where space permits.
19 However, in some cases we are unable to install a circuit
20 switcher ("CS") and/or a circuit interrupter ("CI") in
21 series due to space constraints. In order to achieve the
22 exact work scope recommended by the Company in 1991, we
23 would have to completely re-engineer our existing

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1 transformer vaults, and raise and reinforce the walls to
2 support both the CS and/or the CI. This adds significantly
3 to the cost and outage duration required to complete the
4 project and achieve the 1991 intent.

5 Since 1991, we have experienced significant
6 advancement in digital technology applied to transfer trip
7 schemes using digital T1 communications. We have deployed
8 these systems throughout substations, and our experience
9 has been extremely favorable both in reliability,
10 availability, and achievement of repeated high speed
11 clearing of faults. In addition, these digital systems are
12 far less susceptible to misoperations than the use of older
13 analog audiotone transfer trip schemes. This technology
14 has also proven to be far better than the High Speed AGS
15 technology that was deployed in the 1950's for high speed
16 clearing. In today's world of sensitive loads, the old AGS
17 schemes are not preferable to achieve power quality
18 standards, as they intentionally apply an A-Phase ground
19 for the remote end to sense the fault and then send signals
20 to the respective breakers to open.

21 The Digital Transfer Trip ("DTT") scheme meets the
22 intent for fast clearing resulting from the 1990 Seaport
23 fire incident. This technology was not available in the

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1 1990's, and was, therefore, not proposed as a solution at
2 that time. It is also important to note that the
3 installation of DTT systems requires much shorter outage
4 duration, as most of the work is non-outage related.

5 Q. What is the current status of this program?

6 A. We have assessed and support the continued need for the
7 program - either a local high side clearing device
8 (original scope) or two lines of DTT and a motor operated
9 disconnect or removable flexible link (modified scope). In
10 addition to the Seaport type incident protection, these
11 designs also allow for faster fault clearing and switching
12 capabilities to increase our operational reliability. We
13 assessed this program in late 2010/early 2011, and at that
14 time, we had 134 transformers to address in order to meet
15 the 1991 commitment. Fifty four of these were in vaults
16 that have sufficient space to accommodate a local high side
17 clearing device. In these locations, we will pursue the
18 original scope of the program. However, due to space
19 limitations and bus work design, a modified scope, with two
20 lines of DTT and either a motor operated disconnect or
21 removable flexible link will be implemented in the
22 remaining eighty vaults.

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1 The modified designs will optimize the implementation
2 cost of the overall program, while meeting the 1991 intent.
3 The choice of design depends on the exact station
4 configurations and space availability. All three design
5 proposals use DTT as a primary means to provide high speed
6 clearing of transformer secondary faults from the supply
7 stations. In cases where the installation of a circuit
8 switcher is cost prohibitive, we will install transformer
9 high side isolation using either flex links or a motor
10 operated disconnect switch along with DTT in lieu of
11 circuit switchers to provide for local high side clearing.
12 The flex links and the motor operated disconnect switches
13 provide an alternative isolation method for transformers
14 where the installation of a circuit switcher has proven to
15 be extremely expensive and time consuming.

16 By incorporating the above design changes, our current
17 cost estimates indicate that the overall spending for the
18 134 transformers will be in order of \$249 million, which is
19 significantly less than our cost estimate of at least \$335
20 million for implementing the 1991 proposed design changes.

21 Q. Has this proposal been discussed with DPS Staff?

22 A. Yes, it has. We held a conference call with Staff on
23 January 27, 2011 to discuss this approach, and provided

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1 follow up correspondence on February 23, 2011. Staff felt
2 that our revised plan was a reasonable alternative, in
3 light of the space constraints and given the new technology
4 that is now available, and asked that we provide a full
5 assessment of the program at the time of the Company's next
6 rate filing, including discussion of the cost, schedule,
7 and continued need for the program. Details regarding the
8 current cost and schedule for the program can be found in
9 the document titled "Substation Area Reliability Project -
10 Phase II" The projected costs for installation of the
11 modified design are \$11.22 million in 2013, \$11.37 million
12 in 2014, and \$11.35 million in 2015.

MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-7)

14 Q. Please describe the Security Enhancements Program shown on
15 Exhibit __ (IIP-6).

16 A. The Security Enhancements Program continues to upgrade
17 security systems at Bulk Power System ("BPS") stations.
18 BPS stations became the focus of security enhancements
19 beginning in 2010. Security upgrades include new CCTV
20 systems, card access and perimeter protection. Since 2010,
21 we have completed upgrades at Millwood, Ramapo, and
22 Pleasant Valley Substations. The following stations are

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1 currently in progress, and we expect to complete them in
2 2012/2013:

- 3 • Eastview
- 4 • Fresh Kills
- 5 • Pleasant Valley
- 6 • Farragut
- 7 • Gowanus
- 8 • Rainey PURS

9 The following stations are in the planning and/or
10 procurement stages, and we expect to complete them in
11 2013/2014:

- 12 • Tremont
- 13 • Pleasantville
- 14 • East Fishkill
- 15 • Sprain Brook
- 16 • Dunwoodie
- 17 • Goethals
- 18 • Rainey S/S

19 Following this grouping, the remaining two BPS stations,
20 East 13th Street and Buchanan, will be addressed.

21 The security upgrades at the listed stations are necessary
22 to meet the requirements of Con Edison Security

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1 Specification CE-ES-2002-24. This program will bring
2 substation facilities into compliance with the existing
3 specification. In addition, the facilities will comply
4 with the recommendations of the Department of Public
5 Service Staff with regards to in-place security measures
6 for Bulk Power System substations.

7 Once we have completed the BPS station upgrades, we
8 anticipate that this program will fund other security
9 upgrades such as fencing additions and replacements,
10 capitalized replacement of security related electronics,
11 and expanded use of devices such as card swipe machines.
12 The projected capital costs of this capital program are
13 approximately \$9.1 million in 2013, \$6.5 million in 2014,
14 \$6.7 million in 2015, \$4.4 million in 2016 and \$5 million
15 in 2017.

16 Q. Please describe the Reinforced Ground Grid Program.

17 A. **Reinforced Ground Grid** - Ground grid deficiencies are
18 identified through the Company's periodic ground impedance
19 test program. The reinforcement of the ground grids will
20 be evaluated on a station by station basis and may require
21 the installation of two additional 1000 MCM ground cables
22 and ground rods parallel to existing 1000 MCM ground
23 cables. The actual geometry and number of rods will depend

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1 on the particular station. The ground cables will be
2 connected to existing ground grid. All new
3 structures/equipment being installed in the yard will be
4 connected to the new 1000 MCM ground conductors. In
5 addition, existing structures/equipment that have
6 unresolved high grounding impedance conditions and/or
7 require an additional ground connection will be connected
8 to the new 1000 MCM ground conductors. We have typically
9 performed one upgrade per year under this program.
10 However, we currently have five stations in our working
11 project queue for this program, and anticipate other
12 stations to emerge within the next 1-3 years. Therefore,
13 beginning in 2014, we anticipate performing 2 upgrades
14 annually. The projected expenditures for this program are
15 \$0.8 million in 2013, \$1.6 million annually in 2014-2015,
16 and \$1.75 million annually in 2016-2017.

17 Q. Please discuss the other programs under the Reliability
18 section of Exhibit (IIP-6).

19 A. We will discuss the programs associated with the upkeep of
20 the physical structures that house substation facilities.

21 **Roof Replacement** - This program replaces roofing on
22 buildings at our substations and other facilities where the

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1 roofing has deteriorated beyond repair. The Company has an
2 on-going program to inspect each of approximately 500 roofs
3 once every five years. The roof inspection program
4 proactively identifies roofs in need of repair so that
5 degraded conditions can be addressed in a timely manner,
6 thereby precluding major water intrusion. If not
7 prevented, water intrusion can result in the inadvertent
8 loss of equipment, thereby compromising system reliability.
9 Degraded roofs that have reached the end of their service
10 life and cannot be economically repaired are replaced under
11 this program. The projected capital expenditures for this
12 program are \$3 million annually in 2013, 2014, and 2015,
13 and \$3.3 million annually in 2016 and 2017.

14 **Switchgear Enclosures Upgrade** - This program modifies and
15 upgrades selected outdoor switchgear enclosures throughout
16 the system to provide weatherproof switchgear cubicles.
17 The switchgear cubicles and associated bus runs in a number
18 of substations require upgrading. These outdoor switchgear
19 housings are typically about 40 years old and have been
20 weathered by years of exposure to the outside environment.
21 The exterior doors may no longer close and seal correctly
22 subjecting system equipment to the elements and adverse
23 weather. In addition, sections of bus may have developed

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1 leaks and are prone to water intrusion. The upgraded
2 enclosures reduce weather-intrusion related trip outs,
3 unscheduled outages, and erroneous alarms. Enclosure
4 upgrades typically include replacements or improvements to
5 doors and Kemper Sealing of outdoor bus enclosures. The
6 projected expenditures for this program are \$1 million
7 annually in 2014 through 2017.

8 **Stabilization of Pothead Stand Supports/Settlement** - The
9 Corona substation was constructed on reclaimed land, and
10 many of the structures and buried facilities are settling,
11 resulting in some damage to foundations, troughs, conduit,
12 splice boxes and cable. Several Corona substation
13 settlement projects to correct settling of cable trenches
14 and several pothead stands have already been successfully
15 completed at the Corona substation. Stabilization of
16 additional pothead stands, using screw piles and foundation
17 work, is still required. We have also found that similar
18 settlement issues are present in Astoria East and
19 Queensbridge substations. This is a multi-year project to
20 correct the station equipment settlement problems by the
21 use of screw piles and foundation work. The funding for
22 this project is \$1 million annually in 2013-2015, and \$1.1
23 million in 2016-2017.

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Construct Relay House Canopies – Under this program, the Company installs weatherproof enclosures to preclude deterioration of the relay cabinets while providing for safe inspection, maintenance and repair under all weather conditions. Relays are usually housed in a metal cabinet that is designed to be water-tight and installed either inside or outside a substation building. When these metal cabinets are exposed to weather, they deteriorate with time. In various substations, several of these exposed relay cabinets have deteriorated and need to be repaired or replaced. The installation of the canopies is a long-term solution to protect relay cabinets from inclement weather and enhance the reliability of the electric system. The canopies consist of a structural frame with a roof and partial siding attached to the frame and panels protecting the roof and sides of the enclosure. Capital expenditures for this program are projected to be approximately \$1.1 million annually for 2014-2017.

Q. Please discuss the Fire Suppression System Upgrade program.

A. Fire detection and deluge systems are critical components for quickly and safely responding to a fire event in our substations. Our fire detection systems and deluge systems, in certain cases, are approaching their expected

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1 end of life and are beginning to show signs of
2 deterioration or decreased reliability. The purpose of the
3 **Fire Suppression System Upgrade** program is to perform
4 upgrades, replacements, and/or new installations of fire
5 protection, suppression, deluges, and detection systems at
6 various substations. The fire detection upgrades include
7 the replacement of fire/heat/smoke detection equipment,
8 wiring, control systems, alarm devices, etc. used to detect
9 a fire, initiate an alarm and, in many cases, activate a
10 deluge system. The deluge system upgrades include the
11 replacement of piping, pumps, spray nozzles, wiring,
12 control systems, and enclosures associated with delivering
13 water to a fire once it is detected.

14 This program will fund modification of the existing
15 substation fire protection fire pump piping by adding a
16 fire pump discharge valve and a fire pump test header
17 including valve, piping, and test header manifold. This
18 will be performed at 45 substations. This is a multi-year
19 project, starting in 2008, that is projected to complete at
20 least six substations per year. This program will also
21 fund the installation of clean agent fire suppression
22 systems in various dielectric fluid enclosures

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1 (pumping/cooling/PURS plants). Fifty-seven locations have
2 been identified. This project is a multi-year effort.
3 Capital expenditures for Fire Suppression System Upgrade
4 program are projected to be \$8 million in 2013, \$7 million
5 in 2014, \$5.4 million in 2015, \$6.5 million in 2016, and \$7
6 million in 2017.

7 Q. Please discuss the Small Capital Equipment program.

8 A. The **Small Capital Equipment program** funds various smaller-
9 scoped equipment-related modifications and upgrades that
10 are important to system reliability and safety at
11 individual substations. In contrast to the Facility
12 Upgrade Program, which addresses structural improvements to
13 the substation yard and buildings, this program funds
14 equipment-related improvements at the various substations.
15 Examples of the types of improvements made under this
16 program include: feeder pressure alarms, station monitoring
17 and control system improvements, equipment related
18 enclosures and foundations, electrical testing facilities,
19 station light and power upgrades, and other miscellaneous
20 projects. This program is required to fund small equipment
21 related projects that are not covered by other capital
22 programs. We currently have identified an estimated \$7.5
23 million of projects to be addressed as part of the Small

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1 Capital Equipment program for Substation Operations in the
2 near term. New candidate projects for this program are
3 continually generated as issues are encountered in the
4 field and follow-up Engineering analysis develops solutions
5 for field installation. Capital expenditures for this
6 program are projected to be \$3 million annually during the
7 years 2013-2015, and \$4 million annually in 2016-2017.

8 Q. Please explain the **Buchanan Y94 Wood Pole Bypass** project.

9 A. The Y94 transmission path is an important outlet for the
10 power produced by Indian Point. It was a first generation
11 SF6 bus installation, which has proved problematic over the
12 years. Due to the criticality of the Y94 path, and since
13 the gas insulated bus required frequent repairs, an
14 overhead line was installed as a bypass for the bus in
15 2001. This bypass provided redundancy to the gas insulated
16 bus, and would be put in service if extended repairs were
17 required on the bus. Since 2002, the cost of repairs and
18 regular maintenance of the Y94 SF6 bus at Buchanan have
19 totaled approximately \$4.1 million. The bus is currently
20 out of service due to excessive gas leaks and a required
21 repair to an expansion joint. Due to the unreliable
22 performance of the gas insulated bus, and the high expected
23 cost to repair it, we have reviewed the overhead lines

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1 arrangement to establish measures that will maintain
2 reliability for an extended period of time.

3 Following the review of the wood pole bypass to determine
4 its compliance with Con Edison's specifications and
5 industry applicable codes for primary service, Civil
6 Engineering and Transmission Feeder Engineering determined
7 that modifications are required in order to maintain the
8 wood pole bypass in service. The following work was
9 performed in 2012: improvement to ground-to-wire and
10 structure-to-wire clearances, upgrade of lightning masts,
11 pole replacement, and improvement of site drainage.

12 A second phase of upgrades is required to make the wooden
13 bypass fully permanent. This work will include removal of
14 the existing bypass conductors, hardware, and insulators
15 and replace with new. It will also include a new 345 kV
16 motor operated disconnect switch to be installed at the
17 interconnection point of the line to the Buchanan 345 kV
18 bus, since the retired SF6 bus was equipped with a
19 disconnect switch. This work will be done during the 2014
20 Indian Point 2 refueling outage. The projected capital
21 cost of this work is \$3.5 million in 2014. We have
22 requested \$3.5 million in 2014 to fund this work.

**2. Substation Operations Capital Expenditures to Comply
with NERC Reliability and Security Standards**

- Q. Please discuss the impact on Con Edison of the revision of the definition of "bulk electric system" recently approved by the Federal Energy Regulatory Commission.
- A. On December 20, 2012, the FERC approved a revised definition of "bulk electric system ("BES"), as proposed by the North American Electric Reliability Corporation ("NERC"). The revised BES definition establishes a bright-line threshold so that the "bulk electric system" will include most facilities operated at 100 kV or higher, if they are Transmission Elements, or connected at 100 kV or higher, if they are Real Power or Reactive Power resources. The revised definition removes language in the currently effective BES definition allowing the regional reliability entities discretion in determining which transmission elements are considered part of the bulk electric system. Under the exercise of that discretion, Con Edison's transmission substations and 138 kV sub-transmission system were not considered BES facilities and consequently were not subject to mandatory NERC Reliability Standards. FERC also approved the transition plan for current and newly identified BES facilities, proposed by the NERC, under

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1 which registered entities, such as Con Edison must comply
2 with the requirements of the revised BES definition. Newly
3 identified BES facilities must be brought into compliance
4 with all NERC Reliability Standards by July 1, 2015, which
5 is 24 months after the July 1, 2013 date that the revised
6 BES definition becomes effective for current BES
7 facilities.

8 The revision to the BES definition will impact the
9 Company in at least two key ways. First, an increased
10 number of the Company's facilities will be subject to the
11 NERC standards, thereby increasing the scope of the
12 Company's compliance obligations. Second, the Company will
13 be required to invest in certain additional transmission
14 monitoring and operating equipment. In addition, the
15 revised definition will cause Con Edison to register with
16 NERC as a "Transmission Operator" and "Transmission
17 Planner," in addition to its current registration. Being a
18 "Transmission Operator" and "Transmission Planner" will
19 also cause Con Edison to be subject to additional NERC
20 requirements, thereby increasing Con Edison's compliance
21 obligations.

22 Q. Has the Company established any programs to implement the
23 changes that will be required when the Company's 138 kV

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1 substations, transmission feeders and related equipment are
2 reclassified as BES facilities?

3 A. Yes. We have two new programs – Disturbance Monitoring
4 Equipment Program and Relay Protection System Redundancy.

5 Q. Please discuss the Disturbance Monitoring Equipment Program
6 for the 138kV substations.

7 A. The new BES definition will trigger the need to install or
8 expand and upgrade Disturbance Monitoring Equipment (“DME”)
9 at 19 of our 138kV substations. The **Disturbance Monitoring**
10 **Equipment Program (138kV)** is required to comply with the
11 new regional NERC Reliability Standard PRC-002-NPCC-1
12 Disturbance Monitoring, as applied to Bulk Electric System
13 facilities. This standard was approved by NPCC Membership
14 (January 2010), NPCC Board of Directors (February 2010) by
15 NERC Board of Trustees (November 2010), and FERC (October
16 20, 2011). DME includes digital fault, sequence of event,
17 and dynamic disturbance recording capabilities.
18 Construction is planned to start in 2014 and to finish in
19 2017. The projected capital costs of this project are \$5
20 million in 2014, \$5 million in 2015, \$6 million in 2016,
21 and \$7 million in 2017.

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1 Q. Please discuss the ongoing program to install and/or
2 upgrade disturbance monitoring equipment at 345kV
3 substations.

4 A. In addition to having to install DME at our 138kV stations
5 as a result in the change in the Bulk Electric System
6 definition, the **Disturbance Monitoring Equipment Program**
7 **(345kV)** is an ongoing program to install DME at our 345kV
8 stations. This program is also required to comply with the
9 new regional NERC Reliability Standard PRC-002-NPCC-1
10 Disturbance Monitoring that became effective in 2011 and
11 immediately applicable to our 345kV transmission stations.
12 We are required to complete installation of this equipment,
13 including digital fault, sequence of event, and dynamic
14 disturbance recording capabilities, by 2015. The program
15 began in 2010. The scope of the program includes:

- 16 • Installation of new DME at 3 transmission substations.
- 17 • Installation of new DME at 1 generating station (East
18 River Unit #1).
- 19 • Expansion and upgrades of the existing DME capability
20 at 17 transmission substations.

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1 The projected capital expenditures for this program are
2 \$8.6 million in 2013, and \$8.8 million annually in 2014 and
3 2015.

4 Q. Please discuss the Relay Protection System Redundancy
5 program.

6 A. The **Relay Protection System Redundancy (Single Point of**
7 **Failure) Program** will install the components needed to
8 address a series of potential protection system failure or
9 removal incidents at 138kV transmission substations and
10 portions of the East River Generating Station, as may be
11 required by the NERC Standard being developed under NERC
12 Project 2009-07 (Reliability of Protection Systems). The
13 program will install components at the substations such
14 that a failure or removal of any one of the identified
15 protection system components will not prevent achieving the
16 BES performance requirements.

17 A review of our facilities indicates that
18 approximately \$350 million could be needed to implement all
19 the changes that may be required. Depending on the time
20 allowed to implement all measures, this could be a multi
21 (10-20 year) program if all of the components noted above
22 have to up installed/upgraded, resulting in an annual
23 spending requirement of \$17.5-\$35 million. Pending

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1 clarification of the requirements, we have planned lower
2 up-front expenditures of \$5 million per year from 2014 to
3 2017.

4 Q. Please discuss the impact of proposed NERC Critical
5 Infrastructure Protection ("CIP") version 5 requirements

6 A. NERC Version 5 CIP Cyber Security Standards provide a cyber
7 security framework for the categorization and protection of
8 BES Cyber Systems to support the reliable operation of the
9 Bulk Electric System. The FERC has established a deadline
10 of March 31, 2013, for NERC to submit the Version 5 CIP
11 Standards. The draft Standards were approved in the NERC
12 Stakeholder balloting process in September 2012. The
13 Version 5 CIP Standards (CIP-002-5 through CIP-009-5, CIP-
14 010-1, and CIP-011-1, the associated implementation plan,
15 and the associated definitions) were approved by the NERC
16 Board of Trustees on November 26, 2012 and are currently
17 being prepared for filing with applicable regulatory
18 authorities.

19 **CIP-Security Upgrades Program** - Substations that fall
20 into certain CIP facility classifications will require
21 physical and electronic perimeters for their critical cyber
22 assets in compliance with the Version 5 CIP standards.
23 These perimeters will be established through the use of

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1 security features such as card access control to equipment,
2 same day access revocation, and SCADANET expansion.

3 CIP version 5 will significantly change the
4 requirements for determining which cyber assets are within
5 the scope of the standards. In general, CIP version 5
6 places just about all of the computers in a substation in
7 scope, regardless of how accessible these computers are to
8 the outside world. Any computer system or group of
9 computer systems that, if rendered unavailable, degraded,
10 or misused, would within 15 minutes adversely impact one or
11 more BES Reliability Operating Services is considered a
12 cyber asset and must meet CIP version 5 security standards.
13 The expanded scope of the BES definition will increase the
14 number of stations which will require CIP upgrades. To
15 meet the various requirements of CIP Version 5 at these
16 stations, the BES Cyber System/Asset requires significant
17 physical access protection/controls, electronic access
18 protection/controls, and controls on the design information
19 (access control to the drawings designs). In addition,
20 engineering drawings and designs of BES stations will
21 require upgraded security including storage and access
22 protocols. Work scopes and priorities to meet these
23 standards are currently under development, and we expect

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1 construction activities to commence in 2013 and continue
2 until all required equipment has been installed, currently
3 projected as 2015. The overall capital cost of this
4 initiative is expected to be approximately \$3 million,
5 i.e., \$1 million annually for 2013-2015.

6 **3. Substation Operations Reliability O&M Program Changes**

7 Q. Will there be incremental O&M expenses associated with
8 implementing CIP version 5?

9 A. Yes. There will be incremental resource additions and
10 associated training / expenses required for the
11 establishment of dedicated Cyber Security personnel in
12 Substation Operations, System and Transmission Operations,
13 and Central Engineering to meet the requirements of CIP
14 Version 5. These personnel will be responsible for the
15 implementation and monitoring of the Company's improved
16 cyber security policies and procedures, as well as the
17 development and implementation of the employee training
18 modules. In addition to the staffing that will be
19 required, funding is required to provide annual training to
20 existing staff, as will be required by this standard.
21 Projected annual O&M expenses for these initiatives are
22 \$1.31 million in 2014, and then increasing to \$1.36 million
23 annually thereafter.

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1 Q. Does Substations have any O&M programs associated with
2 Reliability?

3 A. Yes. We have a \$1.15 million program change for Relay Trip
4 Checks and Calibrations. The Protective System and Testing
5 department performs all required scheduled maintenance on
6 the relay protection system to maintain the continued high
7 level of system reliability on the Transmission and
8 Distribution System. Relay Trip Checks and Calibrations
9 are performed on a scheduled basis to comply with internal
10 procedural requirements, as well as adhering to established
11 NERC, NPCC, FERC guidelines. The volume of planned work
12 scheduled in the rate year is greater than the actual
13 volume of planned work performed in the historical year.
14 In addition, the historical year values for this item are
15 artificially low due to a significant shift of
16 organizational labor required to support a time dependant,
17 high priority developer interconnection project - the BEC /
18 Hess interconnection project.

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B. System and Transmission Operations Reliability

1. System and Transmission Operations Reliability Capital Programs and Projects

Q. Please discuss the project to replace the battery UPS systems at the Energy Control Center, shown on Exhibit __ (IIP-6).

A. The critical systems at the Energy Control Center ("ECC") are protected by three 100kva Uninterruptible Power Supply ("UPS") battery systems. Without battery support, computer equipment would shut down during any type of loss of power, interrupting operability and potentially corrupting data files. The ECC's critical systems require large battery support to provide protection and to allow uninterrupted transfer of load to the back-up diesel generators during power interruption. The batteries for UPS1, UPS2 and UPS3 were delivered in 1998, and placed into service in 2001 for UPS1 and 1998 for UPS2 and 3. The batteries are isolated in three different rooms for protection and separation. This project will replace the battery systems for UPS #1, #2, and #3 based on test results and age. The batteries will be replaced one room at a time with critical load transferred to another UPS during replacement to maintain

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1 continued operation of the critical computer systems.

2 Replacement of the battery systems for UPS #2 and #3 began
3 in 2012 and will be completed in 2013 at capital cost of
4 \$.2 million in 2013. The UPS #1 system is planned for
5 replacement in 2016 at a capital cost of \$.25 million.

6 Q. Please discuss the Energy Control Center/Alternate Energy
7 Control Center Security Upgrades project

8 A. The Energy Control Center/Alternate Energy Control Center
9 Security Upgrades project will add, as required, new and
10 improved physical security systems to the Energy Control
11 Center and Alternate Energy Control Center. This will
12 include card access, security cameras, biometrics or
13 automated applications to monitor security. The control
14 centers provide an essential service, each having full
15 remote control capability of the electric and steam
16 systems. Physical security systems must be maintained at
17 levels that provide proper access control and allow for
18 both local and remote monitoring. The projected capital
19 costs of this project are \$0.25 million in 2014, \$0.6
20 million in 2015, and \$0.2 million in 2016.

21 Q. What are the Company's plans for improving the reliability
22 of the transmission system?

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1 A. We will discuss the following programs, listed in Exhibit
2 (IIP-6), that maintain or improve the reliability of the
3 transmission system: the Emergent Transmission Reliability
4 program, Re-conductor of Dunwoodie - Sprain Brook
5 Transmission Corridor Project, L-Line Splice and Dead End
6 Assembly Project, Upgrade of Overhead 345kV Transmission
7 Structures and the Transmission Feeder Pipe Support at
8 Queensboro Bridge Project. As discussed previously, the
9 Re-conductor of Dunwoodie - Sprain Brook Transmission
10 Corridor, the L-Line Splice and Dead End Assembly Project,
11 and Upgrade of Overhead 345kV Transmission Structures are
12 components of our storm hardening efforts on the overhead
13 transmission system.

14 Q. Please describe the "Emergent Transmission Reliability"
15 Program, as shown on Exhibit (IIP-6).

16 A. The **Emergent Transmission Reliability program** addresses
17 recently identified reliability and load relief issues on
18 the transmission system that require resolution in the near
19 future and that can be resolved through project work of
20 relatively limited scope and duration. Such identified
21 projects are scheduled for work under this program. In
22 addition, and very importantly, the program provides
23 funding for non-forecasted projects that emerge and must be

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1 performed expeditiously in order to maintain reliability or
2 reduce environmental risks. When such non-forecasted
3 projects emerge and require immediate response, we may
4 displace scheduled projects in this program to address the
5 more immediate issue.

6 Q. Please provide an example of a non-forecasted project that
7 required immediate response under this program.

8 A. A recent example of a non-forecasted project that required
9 expeditious action is the joint replacement in manhole
10 M10349 of feeder M51. In the second quarter of 2011, 345
11 kV pipe-type transmission feeder M51 failed at manhole
12 M61736. The failed semi-stop joint was subsequently
13 opened, inspected, and replaced under the feeder failure
14 program. As a result of this failure, another semi-stop
15 joint on feeder M51 located in manhole M10349 was selected
16 for X-ray inspection based on a similar field condition as
17 the failed joint. In March 2012, the joint in manhole
18 M10349 was proactively opened and inspected due to
19 irregularities noted in the digital x-rays taken on the
20 joint. Visual inspection of the joint confirmed X-rays and
21 revealed similar cable damage to the joint that previously
22 failed. The damaged joint was proactively removed and
23 replaced. The feeder was returned to service in April

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1 2012, well ahead of the critical summer load period. The
2 345kV pipe-type transmission feeders are critical to
3 overall system reliability. By proactively addressing this
4 suspect joint in M10349 under the Emergent Transmission
5 Reliability Program in an expedited timeframe, a potential
6 future failure that could have taken the feeder out of
7 service during a high load period and required 4-5 weeks to
8 repair was avoided and overall system reliability was
9 increased.

10 Q. Please provide examples of the identified emergent projects
11 that are scheduled to be performed under this program.

12 A. The following projects exemplify the type of previously
13 identified emergent work that will be scheduled and
14 performed in 2013 or 2014 under this program. However more
15 urgent, previously unidentified projects requiring
16 immediate action may emerge and displace these previously
17 identified projects. Details of each of these projects are
18 provided in Exhibit (IIP-6).

- 19 • The replacement of transition couplings on feeder 38B11T
20 will eliminate leaks that present environmental and
21 reliability risks.

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- 1 • The installation of new support clamps for porcelain
2 insulators on pressure switch assemblies at pothead
3 stands for a select group of feeders.
- 4 • The replacement of the riser cables, riser stub pipes and
5 supports, and cable terminations on feeder 69M41 at
6 Cherry St Substation will provide a permanent solution
7 for leaks that present environmental and reliability
8 risks.
- 9 • The installation or replacement of rectifiers is required
10 to maintain the cathodic protection of buried pipe type
11 cables.
- 12 • The installation of pressurized fluid ("BICC-type")
13 reservoirs on critical and sensitive feeders to maintain
14 sufficient operating pressure to prevent the catastrophic
15 failure of the terminations until emergency switching to
16 de-energize the feeder in the event of failure of the
17 pressurizing plants.
- 18 • The upgrade of obsolete fluid reservoirs for select low
19 pressure fluid-filled feeders prevents leaks that present
20 environmental and reliability risks.

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1 Capital expenditures for the Emergent Transmission
2 Reliability program are projected to be \$10 million in
3 2013, and \$9.5 million annually from 2014 to 2017.

4 Q. What other capital projects are included as part of the
5 "Reliability" for Transmission Operations?

6 A. The other projects addressed are: the Re-conductor of
7 Dunwoodie - Sprain Brook Transmission Corridor, the L-Line
8 Splice and Dead End Assembly Project, and upgrade of the
9 Overhead 345kV Transmission Structures. As discussed
10 previously, these projects are components of our storm
11 hardening efforts on the overhead transmission system.

12 Q. Please describe the Re-Conductor Dunwoodie - Sprain Brook
13 Transmission Corridor Project.

14 A. The **Re-Conductor Dunwoodie - Sprain Brook Transmission**
15 **Corridor Project** involves the replacement of the
16 compression fittings on the overhead 138kV feeders 99941
17 and 99942 on the E-Line between Dunwoodie and Sprain Brook
18 substations. Each of these 138 kV feeders, which are
19 approximately 1.5 miles in length, was originally built in
20 1956 with single-wire bundle 1033 kcmil 54/7 ACSR conductor
21 and later rebuilt and reinforced in 1965 when the portion
22 of the line between Sprain Brook and Dunwoodie was upgraded

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1 to larger single-wire bundle 2156 kcmil 84/19 ACSR
2 conductors.

3 Significant problems with compression fittings have
4 surfaced on these feeders. Past thermographic inspection
5 detected three dead end fittings operating at high
6 temperatures, which were then replaced in 2006. Subsequent
7 testing at The National Electric Energy Testing, Research
8 and Applications Center ("NEETRAC") indicated that the
9 fittings were either at end-of-life or could reasonably be
10 expected to be at or near end-of-life in the near future.
11 In addition, this year EPRI (Electric Power Research
12 Institute) performed a study on our compression fittings
13 (dead end and in line) and determined that it would be
14 advisable to replace the existing units with new units due
15 to their advanced age. Failure to replace these fitting
16 now increases the likelihood that we will experience an
17 unplanned outage or a feeder failure on these important
18 transmission lines. This work will be performed in 2013,
19 and capital expenditures are projected to be \$2.4 million
20 in 2013.

21 Q. Please describe the L-Line Splice and Dead End Assembly
22 Project.

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1 A. The **L-Line Splice and Dead End Assembly Project** involves
2 the reinforcement of the in-line and dead end assemblies on
3 the overhead feeder 398 on the L-Line between Pleasant
4 Valley Substation and the Connecticut border. The splices
5 on feeder 398 are similar to those on feeders 99941 and
6 99942, and we are planning to address those issues on
7 feeder 398 as well. Feeder 398 consists of single-wire
8 bundle 2156 MCM ACSR (aluminum conductor steel reinforced).
9 Feeder 398, which is approximately 17.8 miles in length,
10 was originally built in 1964. Significant problems with
11 compression fittings have also surfaced on feeder 398.
12 Similarly to the Dunwoodie feeders, thermographic
13 inspection has detected dead end fittings operating at high
14 temperatures and NEETRAC testing has indicated that the
15 fittings are approaching end-of-life and also indicated
16 that the conductor does not meet minimum ASTM requirements,
17 possibly as a result of a manufacturer defect. The Company
18 plans to reinforce this circuit in 2014 before further
19 degradation occurs and additional end-of-life issues
20 develop, which could result in unplanned outages or a
21 feeder failure. Capital expenditures for this project are
22 projected to be \$2.9 million in 2014.

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1 Q. Please describe the project **"Upgrade of Overhead 345kV**
2 **Transmission Structures."**

3 A. This project provides for upgrades on specific 345 kV steel
4 lattice towers selected based on engineering analysis. The
5 reinforcement of these towers decreases the likelihood of
6 tower failure during weather events. Through selective
7 reinforcement of towers, this project decreases the
8 likelihood and impact of multiple failures resulting from
9 cascading since reinforced towers are better able to
10 withstand the loads that would result from adjacent tower
11 failure. Priority is given to towers with the highest risk
12 on critical corridors as specified by System Operations.
13 Towers on six critical circuits are being completed in
14 2012, and upgrade work will continue in 2013 and subsequent
15 years on circuits lines with higher risk assessments.
16 Upgrading existing structures will reduce potential tower
17 failures and improve reliability. The projected capital
18 expenditures for this project are \$1.5 million in 2013 and
19 \$2 million annually in 2014-2017.

20 Q. Please discuss the Transmission Feeder Pipe Support at
21 Queensboro Bridge Project.

22 A. The **Transmission Feeder Pipe Support at Queensboro Bridge**
23 **Project** involves six 138kV solid dielectric feeders and six

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1 69kV nitrogen-filled feeders traversing the Queensboro
2 Bridge. Based on visual inspections, several supports
3 along all feeders are in need of replacement or re-
4 alignment. The damaged or missing supports cause the
5 feeders to be improperly supported and have caused abrasion
6 to the coatings. In many places the pipes are improperly
7 resting directly on the concrete piers and steel beams.
8 The abrasion to the pipes due to improper support causes
9 the coating to become damaged and leaks to occur.
10 Mitigating these problems by installing new supports will
11 avoid costs for leak emergency response and remediation.
12 The existing feeders were analyzed under bridge live load
13 conditions for the full range of anticipated thermal and
14 operational temperature movements and under bridge live
15 load conditions. The solution is to support a system of
16 hanger supports at the ends of the feeders by the piers and
17 additionally, to install new rollers in places that are
18 damaged, and to install rollers on all sides of the feeders
19 in targeted locations in order to prevent the lateral
20 movement of the feeders off of the rollers. The forces and
21 displacement resulting from the feeder analyses was used to
22 design the new supports at the piers and to re-design the
23 malfunctioning feeder supports. A temporary structural

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support system to provide access to complete the repairs is also required due to the fact that the cables are located beneath the bridge deck and above the river. The projected capital expenditures for this project are \$3.6 million annually in 2013-2014 and \$3.5 million in 2015 to complete this work.

2. System and Transmission Operations Reliability O&M Program Changes

Q. Are there any System and Transmission Operations O&M requests associated with the Reliability category?

A. There are seven O&M requests in total. One of them has already been discussed as part of our overall activities related to NERC CIP V5 requirements. The remainder will be discussed now.

Transmission Planning and System Operations are both seeking additional funding for new staff positions associated with NERC Standards and Compliance. Con Edison responsibilities related to NERC compliance continue to grow, necessitating a one FTE staffing addition to the Standards & Compliance Section to manage the Company's compliance-related activities. With the anticipated FERC revision to the Bulk Electric System definition, the

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1 Company's BES facilities subject to NERC compliance are
2 expected to significantly increase. In addition the FERC
3 mandated changes to the BES definition will result in the
4 need for Con Edison to register as a NERC certified
5 Transmission Operator and a Transmission Planner. We are
6 seeking an additional \$200,000 annually to staff these
7 positions, starting in 2013.

8 The Transmission Planning Department within S&TO will
9 establish a new position reporting to the Manager of
10 Standards and Compliance. The position will support
11 compliance with expanding NERC standards, particularly
12 those arising from the issuance of CIP Version 5 and from
13 the expected revision to the "Bulk Electric System"
14 definition. The latter will include reliability
15 requirements and the need for Con Edison to register as a
16 NERC certified Transmission Operator and a Transmission
17 Planner. Among the duties of this position will be:

- 18 • Manage NERC standards development and NERC Compliance
19 Monitoring and Enforcement Program
- 20 • Assist Company SMEs preparing for compliance audits,
- 21 • Bulk Electric System (BES) definition impact
22 assessment,

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- 1 • Coordinate evidence preparation and RSAW
2 documentation,
- 3 • Coordinate company responses to and compliance
4 assessments of reportable system events,
- 5 • Support Company cyber security compliance including
6 Technical Feasibility Exception submittals and
7 assessments of CIP version 5 impacts,
- 8 • Support Company program to respond to NERC Alerts,
- 9 • Support upcoming activities including
10 registration/certification of Con Edison as a NERC
11 Transmission Operator and Transmission Planner.
- 12 • Assist in assessment and dissemination of NERC
13 documents including Compliance Application Notices,
14 Compliance Assessment Reports, Lessons Learned and
15 Violation Notices.

16 The projected annual cost for this position will be
17 \$100,000 commencing in 2013.

18 In addition, the System Operation Department within
19 S&TO will establish a Transmission Operator Planner
20 Compliance position. The primary focus of this position
21 will be to strengthen the training efforts at the Energy
22 Control Center (ECC) by adding a training position in order

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1 to meet the current needs of the operators. The new
2 Electric Reliability Organization, NERC is requiring a
3 systematic approach to training to be followed by those
4 entities that can affect the bulk power Interconnection.
5 NERC certification is becoming mandatory and the necessary
6 training must be established and conducted annually to
7 provide the continuing education hours to maintain operator
8 certification. This position will also be responsible for
9 enhancing compliance monitoring. Some of the duties
10 involved are as follows:

- 11 • Monitor and modify S&TO Specific training programs as
12 appropriate to train operators in the skills needed to
13 safely and reliably operate the electric systems
- 14 • Maintain compliance with training requirements
- 15 • Facilitate NERC certification of applicable operators
- 16 • Facilitate continuing education credits to maintain
17 continuous certification of applicable operators
- 18 • Prepare for NERC evaluations and NPCC compliance
19 audits
- 20 • complete recommendations arising from NERC evaluations

21 The projected annual cost for this position will be
22 \$100,000 commencing in 2013.

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1 Q. Please discuss the program changes needed to reflect
2 District Operator Position and the System Analyst (Watch
3 Engineer) positions that were not reflected in the historic
4 year.

5 A. System Operations is also requesting staffing related
6 funding for three additional positions. These two program
7 changes are due to discrepancies in the historic year
8 actuals that existed due to open positions that existed in
9 that time period.

10 Two vacancies existed in key 24x7x365 shift positions
11 within System Operations at the end of 2011. The District
12 Operator Position and the System Analyst (Watch Engineer)
13 are both critical to the safe and reliable operation of the
14 electric system. Both vacancies were filled in 2012, and
15 the program changes (\$100,000 for each position) reflect
16 the difference between our 2011 historic year spending and
17 our projected rate year expenditures. In both cases, during
18 the absence, the remaining shift personnel covered the open
19 shifts through reductions in allotted training time and
20 available vacation time.

21 The District Operator is necessary for insuring the
22 safety of Company personnel and the public. This position
23 is responsible for maintaining continuity of service to

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1 customers, coordinating the operation of the electric
2 transmission and distribution systems. Key functions
3 performed by the District Operator include:

- 4 • Administering protective measures prescribed by
5 Company rules for the protection of personnel and
6 equipment when work is to be performed on intermediate
7 or high voltage equipment on the electric system
- 8 • Ordering the necessary switching, grounding and
9 identifying of electrical equipment as required to
10 attain the highest degree of safety and in accordance
11 with the "General Rules and Regulations Governing Work
12 on System Electric Equipment".
- 13 • Administering the Work and Test Permit procedure with
14 Field Representatives, Station Operators and Field
15 Engineering Representatives.
- 16 • To direct switching and protective measures for
17 equipment under the jurisdiction of the System
18 Operator.
- 19 • To maintain adequate electric capacity in all areas of
20 his district to meet customers demand.
- 21 • To take appropriate action when a feeder or unit of
22 equipment is disconnected from the system

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1 automatically (this includes ordering fault location,
2 identification, repair, testing and restoration of
3 faulted equipment). The District Operator will
4 evaluate the impact the loss of this equipment has on
5 the system and expedite its return accordingly.

- 6 • Coordinating the Operation of the Electric,
7 Transmission and Distribution Systems with Central and
8 Customer Service Substation Operations, Generating
9 Station Personnel and Neighboring Utilities and
10 Prevent Damage to Electric Equipment.

11 The annual cost for the District Operator position is
12 \$100,000.

13 The System Operations System Analyst Watch Engineer is
14 essential in supporting ECC and AECC operations 24x7. The
15 personnel coordinate all watch activities related to the
16 operation of the computer systems at the ECC and AECC. This
17 includes all computer systems associated with the Energy
18 Management System and Feeder Management Systems. This
19 position is responsible for:

- 20 • Providing technical support for database management,
21 display subsystems, and software projects which
22 directly relates to the performance and reliability of

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the Energy Management System, including Power System Security Analysis.

- Insuring that the integrity of the Computer Systems hardware configuration is maintained at all times.
- Insuring that all hardware/software maintenance is performed without jeopardizing the integrity of the Computer System.
- Monitoring all environmental and protective systems that affect the computer facility including Uninterruptible Power Supplies, Diesel Generators, and fire protection systems.
- Providing supervision and oversight for the activities of all personnel within the computer room facility, insuring that all modifications to system software and hardware are properly documented.
- Providing technical support to the E.C.C. operating organizations thru assigned software projects and procedure preparation and modification, and participation on project implementation teams.

The annual cost for the System Analyst Watch Engineer position is \$100,000.

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1 Q. Please discuss the new Human Performance Coordinator that
2 System Operations plans to establish?

3 A. System Operations is seeking funding for a Human
4 Performance Coordinator, which is a key component of an
5 important safety and reliability initiative to improve
6 operations and switching performance at Con Edison. The
7 position is responsible to track and trend human
8 performance statistics within all of Central Operations and
9 to identify, promote, and communicate methods by which
10 human performance may be improved. This position will also
11 provide training to the workforce on human error reduction
12 tools, and establish and implement human performance
13 strategies. The selected individual will prepare, implement
14 and evaluate training and development courses including
15 course design, preparation and instructor coordination for
16 Human Performance. He will also coordinate Human
17 Performance efforts among the various organizations of
18 Central Operations, participate as a member of various
19 Human Performance teams within Central Operation's
20 organizations, and benchmark best practices of Human
21 Performance activities and standardize within Central
22 Operations. The annual cost for the Human Performance
23 Coordinator position is \$100,000.

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1 Q. Does System Operations have any other O&M program changes?

2 A. Yes. The final program change in the S&T0 Reliability
3 Category relates to the maintenance of telecommunications
4 for System Operations. This program maintains the
5 communication infrastructure needed to operate the
6 Transmission and Distribution systems at both the Energy
7 Control Center and the Alternate Energy Control Center.
8 Both provider-based services and the expanded corporate
9 telecommunications networks are required to provide the
10 data and voice communication needs for the operators to
11 operate the system and maintain contact with field
12 operations personnel. During the historic year,
13 expenditures on CCTN maintenance were significantly less
14 than budget. The 2013 budget restores some of these costs.
15 Also, during the historic year, S&T0 received credits for
16 various billing disputes that are not expected in the rate
17 year. These reduce the historic actual expense but are
18 nonrecurring and not included in the 2013 budget. The
19 budget also includes a contingency for an unfavorable
20 resolution of a billing dispute, which will increase the
21 costs of certain circuits. In addition, labor costs
22 continue to rise, and therefore the 2013 budget includes a
23 contingency for rate increases on our expiring maintenance

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1 contracts. The resulting program change is \$469,000 in
2 rate year one.

3 **C. *Electric Operations (Distribution) Reliability***

4 **1. Electric Operations Reliability Capital Programs and**
5 **Projects**

6 Q. What is Con Edison's strategy for improving the performance
7 of the distribution system, and the associated components,
8 that directly support improving reliability while
9 controlling customer costs?

10 A. The Con Edison electric distribution system is one of the
11 most reliable in the world. Con Edison has received PA
12 Consulting Group's 2011 ReliabilityOne™ award for the
13 Northeast Region, Outstanding System-Wide Reliability and
14 the National Reliability Excellence Award. Both awards are
15 given annually to "recognize utilities that have excelled
16 in providing outstanding reliability and customer service
17 to their customers in the face of extraordinary
18 circumstances." We are particularly proud of these awards
19 because during this time we used a capital optimization
20 program to maximize system benefit while controlling
21 expenditures by selecting the reliability projects. .

22 The programs and projects in this category directly
23 support maintaining and improving reliability to both our

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1 underground and overhead distribution systems. Our
2 reliability currently far exceeds the national average, and
3 we are proactively working to find the right balance
4 between highly reliable service and manageable costs for
5 our customers. The New York City and Westchester markets
6 are fairly unique in that we have a high concentration of
7 high rise buildings, mass transit and densely populated
8 service territory. The loss of electricity could affect
9 millions of people, business, transportation, and other key
10 infrastructures throughout our service territory and have a
11 larger impact on our customers than it would in many other
12 parts of the country. At the same time, we realize that
13 affordability of rates is very important to our customers
14 and promotes the long-term sustainability of the Company.
15 Developing an integrated long range plan and implementing
16 tools like Enterprise Risk Management (ERM) and Capital
17 Optimization are helping us to maintain our high level of
18 reliability while controlling bill impacts.

19 Operating contingencies, such as severe storms, winter
20 salt distribution, and high heat days also adversely impact
21 our distribution system and drive up our costs. Con
22 Edison's Reliability programs maintain the readiness of our
23 equipment to provide reliable service day in and day out

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1 and enhance the capability of our system to maintain
2 reliable service during operating contingencies. In
3 addition, Con Edison continues to enhance our Incident
4 Command Structure (ICS) during system emergencies so that
5 we can respond quickly to customers and utilize mutual aid
6 from neighboring utilities to minimize outage impacts
7 during system emergencies. Reliability programs take these
8 concerns into account and target:

- 9 • Infrastructure Improvements
- 10 • Distribution Substation Modernization
- 11 • Overhead Enhancements
- 12 • Storm Preparedness

13 Q. Please describe the Company's network reliability
14 improvement strategy and how it considers not just
15 reliability but also bill impact.

16 A. The Company works to minimize the probability that a
17 network shutdown may affect electric supply to many
18 customers for an extended period. Over the past ten years,
19 the Company has made considerable efforts and progress in
20 identifying, measuring and correcting the factors that
21 affect the reliability of a distribution network.
22 Utilizing statistical models, a network reliability index

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(NRI) of the networks is developed each year and utilized to direct the application of resources for reliability improvement. As a result, the Company has established a Network Reliability Index (NRI) target that all networks should meet. Currently, all but 8 of our 64 networks meet this reliability target and our plan is to bring all networks into compliance by 2014. By specifically targeting the networks that do not meet the target, we are best managing customer costs (by putting the money where it yields the largest return) and managing all stakeholders' exposure to a significant network event. This strategy has resulted in a 10-year distribution network reliability program that identifies what reliability work will be done in each of the 8 networks and what improvement in the NRI these expenditures will yield. The chart titled "2012 Network Ranking" shows the current NRI rankings for our 64 electric distribution networks. Since 2007, we have reduced the number of networks that do not meet not meet the NRI target from 25 to eight. And for those eight networks, the NRI level, i.e., reliability, has been improved over that period and will be at or better than target NRI in 2014.

MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-8)

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1 Q. Was the Company able to take advantage of stimulus funding
2 to help fund these network improvements?

3 A. Yes. Con Edison leveraged stimulus funding to install
4 sectionalizing switches which help improve network
5 performance.

6 Q. How often will Con Edison update this network improvement
7 program?

8 A. Con Edison updates this program every year following each
9 new network load forecast which is based on the summer
10 experience. This iterative process provides an update that
11 is issued prior to the end of each year.

12 Q. Please describe some of the key factors that affect
13 distribution network reliability.

14 A. Key factors that affect distribution network reliability
15 are:

- 16 • Primary feeder and component loads
- 17 • Feeder operational performance history
- 18 • The length and number of connected components of each
19 feeder
- 20 • Feeder cable composition type and age
- 21 • Splice and joint type and age

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- Number of available sectionalizing switches on the feeders
- The amount of load shifted to companion feeders during feeder outages
- Component failure rates as a function of operating temperature
- High potential diagnostic testing results
- Structure heat rejection
- Number of primary feeders

Q. Please describe the history of this program.

A. Over the past ten years, the Company has made considerable efforts and progress in identifying, measuring and correcting the factors that affect the reliability of a distribution network. Utilizing statistical models, a network reliability index (NRI) of the networks is developed each year and utilized to direct the application of resources for reliability improvement.

Q. What strategies will be employed to improve the reliability of the networks?

A. The basic strategies that we continue to utilize are:

1. De-bifurcate feeders

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Existing stations that have the availability of spare breaker compartments will be utilized to split feeders to reduce the number of connected components on each feeder.

2. Install sectionalizing switches on bifurcated feeders

At substations where spare breaker positions are not available, underground sectionalizing switches may be installed on bifurcated feeders. This will permit the isolating of the faulted portion of the feeder and enable quick restoration of the unaffected portion. Stimulus money is currently being utilized to further leverage these investments and will be continued until the stimulus program is completed in 2013.

3. Install sectionalizing switches on long feeders or large spurs

On long feeders, underground sectionalizing switches may be installed to enable disconnection of a failed portion and restoration of the unaffected portion. Stimulus money is also being utilized for this category as described above.

4. Replace lower performing cable programmatically

The Company will continue to target components, including PILC and stop joints that contribute disproportionately to NRI.

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1 5. Network Transformer replacements

2 The Company will continue to replace highly loaded
3 network transformers based on highest priorities in all
4 networks. In addition, it will continue to remove
5 transformers that, on inspection, are found to have
6 excessive corrosion or other indications of potential
7 problems.

8 Q. Please provide an overview of the Electric Operations
9 programs and projects listed in Exhibit (IIP-6) under
10 "Reliability."

11 A. The category "Electric Distribution Reliability" in Exhibit
12 ___ (IIP-6) includes the list of the specific capital
13 programs and projects as well as the "white papers"
14 detailing the work under each program or project to
15 maintain and improve distribution system reliability.

16 Q. Please begin your description of Electric Operations
17 Reliability programs and projects.

18 A. **The Hi-pot Program** – The high-voltage withstand testing
19 (Hi-Pot) of distribution feeders is a proven cable
20 diagnostic that improves the reliability of our
21 distribution networks. The Hi-Pot program is implemented
22 through the application of a high voltage, either DC or
23 Very-Low-Frequency AC, withstand test on distribution

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1 feeders following almost all emergency outages, including:
2 Open-Auto (OA), Fail-On-Test (FOT), and Out-On-Emergency
3 (OOE) as well as all scheduled maintenance outages. The
4 program has demonstrated a near term reliability benefit by
5 acting as a "proof-of-serviceability" test following an
6 emergency or scheduled feeder outage. As a result of our
7 continued optimization of the hi-pot program to determine
8 the most appropriate test voltage levels, duration and
9 intervals, the company no longer targets specific feeders
10 to test. Instead we select feeders based on their
11 scheduled maintenance or the occurrence of emergency
12 outages. As a result of these changes to the program, the
13 current hi-pot program is less than half what it was in the
14 prior rate case. The capital costs for this ongoing
15 program are projected to be \$2.1 million in 2013, \$2.0
16 million in 2014 and \$1.9 million in 2015.

17 **PILC Cable Removal** - This program is designed to facilitate
18 the removal of PILC cable from the primary distribution
19 network feeders. As part of Con Edison's goal of targeting
20 reliability programs as cost effectively as possible, PILC
21 initiatives have been more focused on targeting the worst
22 performing components in the networks that are not meeting
23 the NRI targets outlined above. Working with PSC staff,

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the Company has developed a more balanced approach to PILC removal. The new programs goals of this targeted program, working with other PILC cable removal methods, will now reduce the amount PILC cable to less than 10% of the total population of primary distribution network cable by year-end 2020 after which PILC will be removed through ordinary attrition. The other methods of PILC cable removal include: burn-outs, load relief and other reliability work. PILC removal is optimized through system modeling and targeted investments in NRI networks and as a result, we are requesting roughly 60% of the yearly capital expenditures we were requesting in the previous rate case. The capital costs for this ongoing program are projected to be \$20.8 million in 2013, \$17.0 million in 2014, and \$16.7 million in 2015.

Transformer Remote Monitoring System 3rd Generation - The Transformer Remote Monitoring System ("RMS") provides near real-time transformer data that assists our Distribution Engineering, Regional Engineering, Field Engineering, and Emergency Response Groups in a variety of functions such as monitoring transformer loading and its network protector switch status (open or close), providing data used in developing engineering plans for new customers, reinforcing

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the network system, and most recently measuring temperature and pressure within the transformer. This program installs new third generation RMS transmitters at various network transformer vault locations throughout the distribution system. The transmitter is the individual transformer data collector of the Remote Monitoring System. The Company has leveraged internal funding as well as stimulus funding to accelerate its program to upgrade all network transformer locations with a new third generation RMS transmitter that provides additional operating parameters such as transformer oil level, tank pressure, and oil temperature. The capital costs for this ongoing program are projected to be \$3.1 million, \$1.5 million and \$1.4 million in 2013, 2014 and 2015 respectively. This funding does not include the work that will be completed at the Transformer Shop or the cost of the equipment installed by the manufacturer on new units. The work at the transformer shop, and the cost of transformers supplied with new equipment, are accounted for in the funding for Transformer Purchases.

Transformer Vault Modernization - The Modernization Program for CECONY's Electric Distribution Transformer Vault Structures is a proactive program to mitigate public and system safety concerns regarding structures that have been

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identified as requiring significant upgrades. These upgrades involve significant rebuilds of walls, floors, and roofs of subsurface vaults , involving steel, concrete and masonry components, along with the associated excavation, waterproofing, inspection, and backfill/restoration tasks. This program will address potential safety concerns, provide increased reliability and extend the useful life of our existing structures.

Unattended deficiencies may lead to:

- Employee injuries and trip/fall incidents
- System impacts including damaged transformers from falling debris, damaged cable from falling debris, work stoppages, and delays in restoring system outages
- Fines from the City of New York due to settled structures and cracked concrete.
- Impact to customer premises due to water intrusion at customer service take-offs.

The Company has developed several protocols and procedures to provide direction for implementing a major structural reconstruction program, from structural deficiency reporting to final rebuild. Latest engineering materials including epoxy-coated rebar, concrete roof

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1 waterproof membranes, embedded steel beams, anti-corrosive
2 galvanizing paint over beams and welds, and fiber-
3 reinforced concrete have been incorporated into protocols
4 for complete structural modernization. On-the-Job Training
5 (OJT) has been developed to guide proper construction
6 techniques for concrete, asphalt, and soil. Special
7 inspections and laboratory testing are specified in
8 accordance with national standards. Capital expenditures
9 for this project are forecast to be \$6.5 million in 2013
10 and \$5.0 million annually from 2014 to 2017.

11 **Underground Sectionalizing Switches** - This program installs
12 primary underground sectionalizing switches on targeted
13 network feeders. Installation of primary sectionalizing
14 switches increases network reliability. The sectionalizing
15 switches permit rapid isolation of faulted segments of
16 primary feeders, allowing the portion that is not faulted
17 to be re-energized, and thereby reducing the amount of load
18 shifted to other distribution feeders. This will in turn
19 reduce the failure rates for adjacent feeders that pick up
20 the load of the faulted feeder section, as the loading of
21 the components has an impact on their failure rates. The
22 Company has recently initiated the installation of the new
23 Elastimold Three-Phase Molded Vacuum 40kA switch that

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replaces the old motor operated three phase SF₆ gas insulated switch. The new switch is SCADA ready and can be operated remotely from the Control Center. All new sectionalizing switches will be integrated into the Company's Distribution Automation System (DAS) application for remote operation and control. The work involves installing a new structure or identifying an existing structure to accommodate the equipment, and installing the switch with the associated disconnecting means, fault indicators, and cabling. In order to maintain NRI for all networks below the target of 1.0PU, the program has been extended to add additional switches in networks that may see their NRI worsen due to changes in component failure rate as well as load growth and higher component loading characteristics. The capital costs for this ongoing program, which leverages stimulus dollars, are projected to be \$2.1 million, \$3.0 million and \$2.8 million in 2013, 2014, and 2015, respectively.

Underground Secondary Reliability Program - This system-wide Underground Secondary Cable Replacement Program is targeted to increase overall underground system reliability performance and mitigate public safety events such as electric shock, manhole fire, and manhole explosion

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1 incidents. Damaged secondary cables on the networks reduce
2 the reliability of the secondary network system, stress
3 transformers and remaining secondary mains, and expose
4 customers to a higher risk of outages. The program
5 reinforces the secondary (low-voltage) grid infrastructure
6 by targeting secondary cable based on past performance,
7 age, conductor size, conductor type, cable loading, and
8 underground structures to eliminate congestion.

9 Reinforcement of weak areas of the grid helps to prevent
10 secondary cable failures and public safety events. Using
11 our secondary targeting model, we are able to identify
12 specific networks at greater risk of having secondary
13 events and focus on specific areas within those networks to
14 improve the reliability and performance of the secondary
15 grid. In addition, as the secondary visualization modeling
16 program is implemented and the secondary load flow results
17 become available, the load flows on the secondary system
18 will be used to prioritize the existing repairs as
19 identified from the M&S Plate Targeting Model. The capital
20 costs for this ongoing program are projected to be \$32.5
21 million, \$36.2 million and \$32.7 million in 2013, 2014, and
22 2015, respectively.

23 Q. Is there a risk of no action?

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1 A. Yes. The program is crucial to enhancing the reliability
2 of the secondary grid and enhancing the safety of the grid
3 by reinforcing the weakest areas of the grid and preventing
4 secondary cable failures. This program is instrumental to
5 the Company's long term Enterprise Risk Management strategy
6 to mitigate the risk to public safety posed by secondary
7 cable failures that may result in stray voltage or manhole
8 events.

9 Q. Please continue.

10 A. The following Electric Operations capital projects /
11 programs are also targeted to support "Reliability."

12 **Grounding Transformers** - This program installs grounding
13 transformers on the supply feeder and/or the alternate
14 supply feeder to 13kV and 27kV auto-loops in order to
15 eliminate over-voltages that can occur during a primary
16 feeder fault. The capital costs for this ongoing program
17 are projected to be \$0.6 million annually in 2013, 2014,
18 and 2015.

19 **Shunt Reactors** - This program continues the installation of
20 shunt reactors to prevent over-voltage conditions that may
21 occur when a network protector remains closed or alive on
22 back-feed. The capital costs for this ongoing program are

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1 projected to be \$1.8 million in 2013, \$1.7 million in 2014
2 and \$1.6 million in 2015.

3 **Network Reliability** - The Company will establish new
4 distribution feeders in the Brooklyn/Queens region by
5 continuing to de-bifurcate existing feeders in a way that
6 optimally improves NRI in networks that are above the
7 target. To accomplish this, bifurcated feeders supplying a
8 network or load area via two main runs of cables (legs)
9 will be de-bifurcated, creating two separate feeders with
10 one leg each.

11 These additional feeders will provide a more reliable
12 and balanced supply to the network and more balanced feeder
13 loading during normal conditions (all feeders in service).
14 The increased number of feeders available during
15 contingencies will also mitigate the potential for
16 cascading feeder failures associated with high feeder
17 loading due to shifting load following a feeder failure.
18 Additionally, this program will reduce the number of
19 components (i.e., cable, splices, and transformers) per
20 feeder, thereby reducing exposure to failures and improving
21 reliability. The capital costs for this ongoing program
22 are projected to be \$14.3 million in 2013, \$20.5 million in
23 2014 and \$15.0 million in 2015.

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1 Q. Please discuss the Modernization and Other in Exhibit __
2 (IIP-6).

3 A. A number of reliability programs relating to modernization
4 of distribution substations are grouped under **Modernization**
5 **and Other**. This category includes programs to maintain
6 reliability, alleviate operational problems, and enhance
7 security of our 4kV system. The 4kV system serves around
8 430,000 customers with a peak demand of 1,200MW through a
9 network of 21 interconnected grids fed by 239 unit
10 substations. The replacement of poorly performing or aging
11 transformers, breakers, relays, and switchgear increases a
12 unit substation's overall useful life and maintains
13 reliability on the 4kV system. Upgraded circuit breakers
14 increase reliability by allowing for better reclosing
15 mechanisms and eliminating the high maintenance needed to
16 keep the older breakers in working order. Microprocessor
17 based relays increase accuracy and reliability as well as
18 provide a decrease in maintenance costs. Upgraded
19 equipment modernization will provide operational
20 performance data with improved accuracy and speed. These
21 upgrades allow for quicker response times to prevent
22 failures of unit substation equipment. Some of these
23 improvements will also allow for remote monitoring and

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1 control from the control centers. This decreases
2 restoration time by reducing the scope of tasks such as
3 patrolling feeders to locate faults performed by field
4 personnel. The combined capital costs for these ongoing
5 programs are projected to be \$3.3 million, \$3.5 million,
6 and \$3.5 million annually in 2013, 2014 and 2015,
7 respectively.

8 Q. Describe the programs grouped under the **Modernization and**
9 **Other** category.

10 A. There are five programs:

11 **Failed Transformer Replacement** - This program replaces
12 failed unit substation transformers. Historically, there
13 has been one 4 kV unit substation transformer failure per
14 year. The capital costs for this ongoing program are
15 projected to be \$1.0 million annually in 2013, 2014 and
16 2015.

17 **4kV USS Switchgear Replacement** - Approximately 170 unit
18 substation switchgear "line-ups" have been in service for
19 more than 40 years. In addition, water leaking into some
20 switchgear has caused rust and corrosion conditions within
21 the switchgear. This program is intended to address
22 operational problems and reduce the risk of switchgear
23 failure related to the aging, rusting, and corrosion of

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1 this equipment. The new switchgear houses include modern
2 vacuum circuit breakers, microprocessor-based protective
3 “smart relays” that better protect our switchgear and
4 feeders, and an indoor climate controlled environment for
5 the equipment to operate. The new switchgear houses will
6 require fewer maintenance personnel on site to properly
7 align the older air magnetic circuit breakers into and out
8 of operating positions. The new breakers will create a
9 safer more reliable distribution system. The plan is to
10 purchase and install one switchgear house per year. The
11 capital costs for this ongoing program are projected to be
12 \$1.256 million annually from 2013 through 2015.

13 **USS Life Extension Program** - This program involves projects
14 to extend the useful life of unit substations. The two main
15 components of these upgrades are the replacement of air
16 circuit breakers with vacuum circuit breakers and
17 replacement of electro-mechanical protective relays with
18 microprocessor based relays. This work requires extensive
19 cubicle modifications, new control wiring, verification
20 testing and scheduled feeder outages. Many of the cubicles
21 requiring upgrades will need asbestos and lead abatement
22 during the course of this work. The program plans to
23 replace approximately 28 feeder breakers and perform 7

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1 feeder cubicle relay upgrades per year. We estimate that
2 with the installation of modern vacuum feeder breakers and
3 micro-processor based protective relaying we could lengthen
4 our maintenance cycle from a 3 year program to a 5 year
5 program. This reduction would reduce total maintenance
6 labor expenditures by an estimated 15 to 20 percent. The
7 capital costs for this ongoing program are projected to be
8 \$0.869 million in 2013 and \$1.069 million annually for 2014
9 and 2015.

10 **Tap Changer Position Indicator System** - This program
11 installs tap position indication in the transformer changer
12 compartment at 4kV unit substations and connects the
13 indicator to the Unit Substation Automation (USA) system.
14 This will enable remotely operated voltage reduction and
15 de-loading of transformers during a contingency. To date,
16 160 stations have been completed with 50 stations
17 remaining. The capital costs for this ongoing program are
18 projected to be \$0.075 million annually from 2013 through
19 2015.

20 **Temperature Gauges** - This program upgrades existing
21 temperature gauges to new electronic gauges at all unit
22 substations. These gauges provide improved information
23 regarding the status of transformers at unit substations to

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1 support decisions regarding transformers during
2 contingencies. The implementation of this program will
3 result in more accurate operation of the 4 kV distribution
4 system and fewer customer outages and will provide dynamic
5 rating capability which will allow optimal use of
6 transformer capacity and may defer capital expenditures.
7 The capital costs for this ongoing program are projected to
8 be \$0.1 million annually in 2013, 2014 and 2015.

9 Q. Are there any other programs to improve init substation
10 reliability?

11 A. Yes. The **ATS Installation USS Reliability** program will
12 install new Automatic Transfer Switches (ATS) at unit
13 substations to provide automatic switching to an alternate
14 supply when the primary supply is lost. This will help
15 reduce customer outages as a result of the loss of the
16 primary feeder. The capital costs for this ongoing program
17 are projected to be about \$0.2 million annually in 2013,
18 2014, and 2015.

19 Q. Please describe the programs listed under "Overhead
20 Enhancement" under the "Reliability" category.

21 A. The eleven projects in this category are targeted to
22 improving the overhead system. The overall capital costs
23 for the Overhead Enhancement programs are projected to be

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\$14.5 million, \$14.9 million and \$12.8 million in 2013, 2014, and 2015, respectively. The programs within this category funded at \$1 million or more are:

Osmose (C Truss) Program - Pole inspections are performed to support the reliability of installed poles and safety of the public. The majority of the inspected poles are subsequently treated in order to preserve the pole's acceptable working condition and thereby extend pole life. Inspection and treatment involves "sounding" the pole, taking bore samples, internal treatment, and the installation of a wrap around the base of the pole. In addition to these inspection and treatment programs, some poles are restored to full strength and functionality by way of C-Trussing, which reinforces the base of the pole by installing a metal "C" shaped truss along its side. The installation of C-trusses defers the need to replace the pole, resulting in savings. This program funds the inspection of poles, and the resulting installation of C-trusses (pole reinforcement) and the replacement of poles as needed in line with industry practices. The projected capital costs of this ongoing program are \$1.8 million in 2013, \$1.7 million in 2014 and \$1.6 million in 2015.

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Autoloop Reliability - This program will target selected autoloops in a prioritized manner to maximize the system-wide improvement of autoloop reliability. Projects under this program include the addition of autoloops by extending feeders, installing reclosers (automatic sectionalizing switches) and associated components (poles, cable, etc.). Autoloops are used to automatically isolate a faulted area to minimize the customers that are impacted during an event. The capital costs for this ongoing program are projected to be \$3.7 million, \$3.5 million, and \$3.2 million in 2013, 2014 and 2015 respectively.

Aerial (Okonite) Cable Replacement - This is an ongoing program to replace high failure rate aerial cable on the non-network distribution systems to maintain appropriate reliability targets and support customer enhancement. Replacing existing cable, such as Okonite, with new primary cable through a targeted approach will mitigate the occurrence of customer interruptions due to aerial cable failures. The capital costs for this ongoing program are projected to be \$1.2 million in 2013, \$1.1 million in 2014, and \$1.0 million in 2015.

#4, #6 and Self Supporting Wire - This program targets and replaces the wire with the highest losses on the overhead

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1 system, #4 and #6 copper wire and self-supporting aerial
2 cable (SSC), to maintain appropriate reliability targets.
3 The feeders with the worst performance and highest
4 degradation of cable are given a higher priority for
5 replacement. The capital costs for this ongoing program
6 are projected to be \$2.7 million, \$1.4 million, and \$1.3
7 million in 2013, 2014 and 2015 respectively.

8 **Overhead Feeder Sectionalizing Program** – This program
9 consolidates four automatic and manual feeder
10 sectionalizing programs deployed on non-network open wire
11 systems. These programs are initiated on various devices to
12 enhance system performance and maintain SAIFI and CAIDI
13 performance. Obsolete switches are replaced; damaged and
14 inoperable switches are repaired or replaced; new
15 automation and technologies are deployed; and additional
16 switches are installed on a prioritized basis to enhance
17 both overall system performance and emergency response.
18 The capital costs for this ongoing program are projected to
19 be \$1.7 million, \$1.6 million and \$1.5 million in 2013,
20 2014 and 2015, respectively.

21 **Automated Emergency Ties** - This project will convert 40
22 manually controlled emergency feeder tie switches on 13 kV
23 autoloops to electronically controlled, automatic circuit

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reclosers equipped with wireless communication, remote monitoring and control capability. Operating personnel will be able to monitor and control these reclosers and SCADA switches from the control center, responding more rapidly to distribution feeder events and saving an estimated 45 minutes in restoration time for these types of outages. Customer service will improve as more timely information allows faster response to system disruptions and control of switches eliminates dispatching crews to operate this equipment. Also, engineering personnel can access load data from the line reclosers for system planning. The capital costs for this ongoing program are projected to be \$0.7 million in 2013, \$0.7 million in 2014, and \$0.6 million in 2015.

Overhead Feeder Reliability/VRS Replacement - Vacuum

Recloser Switches are essential for the automatic operation of the 13 kV and 4 kV auto-loops. The Company's engineering specifications require that all units over 20 years old be evaluated for replacement. Many of these switches are in poor physical condition and are well past the manufacturer's duty cycle limits. In addition, specific models cannot properly connect to state of the art

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1 control systems, which limits the ability to control them
2 remotely during outage restoration. The lack of this
3 remote controllability inhibits improved customer outage
4 response. Consequently, we plan to replace all 12kA units
5 that are over 20 years old. The capital costs for this
6 ongoing program are projected to be \$2.8 million in 2013,
7 \$1.5 million in 2014, and \$0.5 million in 2015.

8 **4kV UG Reliability** - Each year, approximately 33,000
9 overhead customers experience a sustained outage due to
10 failures of underground cables, joints, and terminations.
11 Although an underground component of the system, the
12 overhead impact of these failures warrants the program's
13 inclusion under the "Overhead Enhancement" category. This
14 type of underground cable failure typically occurs on
15 either the sections from the station breaker to the first
16 primary riser or on underground portions between overhead
17 portions of the feeder (dips). This program preemptively
18 replaces targeted poor performing 4kV underground cable to
19 reduce the outages associated with failed underground
20 cables, joints, and terminations. The capital costs for
21 this ongoing program are projected to be \$2.3 million, \$2.0

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1 million and \$1.9 million in 2013, 2014 and 2015,
2 respectively.

3 **Overhead Conductor Clearance** – The Company’s Specification
4 E0-4647-C describes minimum clearances from overhead
5 electric facilities as described in the National Electric
6 Safety Code. These clearances are required for the safety
7 of the public and the protection of our distribution
8 system. This program will address 5-7 jobs per year where
9 the distance between conductors and structures are less
10 than the minimum clearance. The work involves replacing
11 leaning poles and/or relocation of the circuit to the other
12 side of the street, into an aerial cable position, or
13 underground, to rectify the situations. The capital costs
14 for this ongoing program are projected to be about \$0.6
15 million in 2013 and \$0.5 million annually from 2014 to
16 2015.

17 **Overhead Secondary Reliability Program** - Defective and
18 undersized overhead secondary wires are the primary cause
19 of complaints regarding low voltage and flickering lights.
20 Also, much of this wire is bare and has excess slack which
21 can cause the wires to “short together” in windy
22 conditions. Replacement of this wire will improve customer
23 service by improving the quality of power delivered to our

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1 customers. Approximately 2,500 spans (500,000 feet) of
2 secondary wire will be replaced under this program on a
3 prioritized basis reflecting reliability indices based on
4 storms, customer complaints, low voltage and other records.
5 The more robust and resilient, new service wire is capable
6 of withstanding greater tree and element exposure. The
7 capital costs for this ongoing program are projected to be
8 \$0.2 million annually for 2013, 2014 and 2015.

9 **Targeted Primary DBC Replacement** - This program replaces
10 primary and secondary Direct Buried Cable (DBC) cables with
11 cable-in-conduit (CIC) to improve the reliability of
12 Underground Residential Distribution (URD) customers and
13 reduce burnout expenditures incurred to repair DBC cables.
14 Based on historical records, approximately 60% of all URD
15 customer interruptions were due to insulation breakdown of
16 direct-buried primary and secondary cables. From 2002 to
17 2007, an average of 1,250 URD customers each year in
18 Westchester and Staten Island (98% of all URD customers)
19 experienced a service interruption due to problems with
20 DBC. These interruptions result in an increase in SAIFI by
21 an average of 22 outages/year and 46 outages/year for
22 Westchester and Staten Island, respectively. On average,
23 it takes 20% longer to locate and repair a fault when it

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occurs on DBC than on the same cable installed in a conduit. Targeted installation of URD cable-in-conduit for both primary/secondary sections and services will reduce the amount of DBC on the system thereby reducing URD customer outage frequency (SAIFI) by approximately 60% and reducing annual repair expenses. The capital costs for this ongoing program are projected to be about \$0.5 million annually in 2013, 2014 and 2015.

Q. Please describe any other Electric Operations Capital Programs in this category.

A. **Vented Service Box Covers** - This program funds the installation of vented *metal* service box covers on the streets and vented *composite* service box covers on the sidewalks. The installation of vented service box covers will help to reduce the buildup of combustible gases associated with secondary events thereby reducing the severity of underground events and enhancing public safety. The installation of vented composite (i.e. electrically insulating) service box covers on the sidewalks will enhance public safety by mitigating stray voltage in addition to facilitating the escape of combustible gases. The program entails replacing all solid covers with vented composite covers on sidewalks and a minimum of one cover

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panel at all service box locations on streets. There are about 181,000 service box locations, and many service box locations require more than one vented cover resulting in a total of 200,500 covers. Installations began in 2009. For 2013, the Company plans to install approximately 5,850 vented service box covers and approximately 10,800 annually from 2014 until 2025 in order to complete approximately 181,000 vented service box locations. The projected capital costs of this program are \$6.7 million in 2013 and \$11.7 million annually from 2014 to 2015.

Street Light Service Reliability (also known as Isolation Transformers) - This program funds the installation of isolation transformers to protect the public from stray voltage associated with street lights and traffic signals. After the program began in the fourth quarter of 2008, Con Edison's ongoing mobile stray voltage scanning of the underground distribution system, coupled with the NYCDOT's application of non-conductive paint to the street light and traffic signal structures, and other measures have been successful in reducing the number of shock incidents from streetlights and traffic signals. The number of shock events attributed to street lights and traffic signals has also declined substantially (from 87 in 2004 to six in

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2011). Thus, the original program goal of installing isolation transformers for all streetlights and traffic signals system-wide is no longer reasonable or cost effective. To optimize our expenditures and best reduce risk to the public, installations will be targeted to facilities with repeat instances of stray voltage and areas of high population density. On April 19, 2012, the Commission issued an order in Case 07-E-0523 authorizing the Company's targeted installation program.

From the beginning of the program, through 2011, we have installed a total of 12,734 units. We projected that the total capital cost to have installed transformers system wide would have been approximately \$167 million through 2025. The cost of the modified, targeted program is projected to be approximately \$11 million through 2025. Our installation goal is 300 units per year at a projected capital cost of \$0.5 million annually in 2013, 2014, and 2015. As we continue to deploy additional transformers, we will continue to evaluate their effectiveness in reducing risk and the cost benefit of the program overall.

Pressure, Temperature and Oil Sensors - The installation of pressure, temperature, and oil level sensors on Con Edison network distribution transformers is funded via this

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1 program. This is one of the transformer failure mitigation
2 programs that have contributed to an 81% reduction in
3 transformer failures since 2005. In 2011, twenty-two (22)
4 transformers were preemptively removed from service due to
5 problems detected via PTO sensors. As of January 1, 2012,
6 approximately 13,500 network transformers had PTO sensors
7 installed and were in service. Con Edison expects to
8 install 2,738 PTO sensors in 2012 and approximately 2,000
9 new PTO sensors per year on average going forward. All
10 network transformers are expected to have sensors installed
11 by December 2017. The projected capital costs of this
12 program are \$3.1 million in 2013, \$3.0 million in 2014, and
13 \$2.8 million in 2015.

2. Electric Operations Reliability O&M Program Changes

15 Q. Please describe Electric Operations' O&M program changes in
16 the "Reliability" category of Exhibit (IIP-6).

17 A. We have changes in the following programs: "Transformer
18 Inspections and Repairs", "Engineering and Other Services",
19 "Structure Inspections and Repairs", "Tree Trimming" and
20 "Field Operations/Unit Substations and Other O&M".

21 Q. Please begin by describing the program changes for
22 Transformer Inspections and Repairs.

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1 A. The **Transformer Inspections and Repairs** program addresses
2 the reliability of the Company's underground network
3 transformers through a comprehensive periodic inspection
4 program (CINDE Inspections). The program includes
5 inspection of transformers, network fuses and circuits,
6 relays, transformer bushings and ground switches. The
7 inspection program also includes taking oil samples,
8 conducting field dielectric tests and replacing fluids
9 where necessary. Funding also covers repairs to
10 transformers and associated devices, transformer gratings
11 and vault structures resulting from inspections. In
12 addition, administrative activities required to document
13 inspections and field conditions are funded under this
14 program.

15 We forecast a reduction Of \$12,755,000 in RYE2014 O&M
16 expenditures for this program as a result of incorporating
17 more condition-based maintenance in order to optimize our
18 inspection cycles, the use of data from our remote
19 monitoring system to conduct "remote" inspections where
20 appropriate, and improved modeling to allow us to vary
21 inspection cycles for units based on their individual risk
22 profiles.

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1 Q. Please describe the O&M program changes for the Structure
2 Inspections and Repairs program.

3 A. The **Structure (Inspections & Repairs)** program conducts
4 inspections of underground distribution structures to
5 identify conditions that can cause or lead to safety
6 hazards or adverse affects on the performance of the
7 structure or equipment. The program also funds the repair
8 of condition found on inspection. Inspections are
9 conducted on a five-year cycle to implement the requirement
10 of the Public Service Commission's Electric Safety
11 Standards that electric facilities be inspected on a five-
12 year cycle. The \$26.7 million increase in this program from
13 the historical period to RYE 2014, is due primarily to the
14 targeted number of inspections to be conducted during the
15 rate year.

16 The Company has about 280,000 underground distribution
17 structures that must be inspected on a five-year cycle.
18 Because each structure must be inspected at least once as
19 part of a five year cycle, the Company must conduct an
20 average of 56,000 inspections each year. In actual
21 practice, the Company conducts the inspection program
22 through a combination of "ad hoc inspections" that occur
23 during normally scheduled work (crews must inspect any

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structure they are assigned to work in) and “targeted inspections” of structures that have not had an ad hoc inspection (a crew is sent to inspect a specific structure). To perform the five-year cycle inspection program most cost effectively, the 56,000 annual inspection rate is accomplished with ad hoc inspections carried out during the earlier years of the inspection cycle followed by ad hoc inspections plus targeted inspections during the later years to complete the inspection cycle. This approach better controls program costs by leveraging ad hoc inspections generated through association with other required work as the greater percentage of the total 280,000 inspections.

The current inspection cycle is the five year period of 2010 through 2014. Following reliance on ad hoc inspections in 2010 and 2011, the Company began targeted inspections in 2012 and will continue conducting targeted inspections in 2013 and 2014. The increase of \$26,665,000 from historic year to RYE2014 is the result of increased targeted inspections (at a cost of approximately \$582 per inspection) during the rate year in order to complete all structure inspections by December 31, 2014. At the completion of the current cycle in 2014, a return to a

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1 primarily ad hoc inspection mode as described above is
2 projected to decrease program expenses by approximately
3 \$27.6 million to historical year levels through RYE2015 and
4 RYE2016.

5 At the time of this rate filing, the Company planned
6 to file a petition asking the Public Service Commission to
7 approve a six month extension in time, to June 30, 2015,
8 for the Company to complete the current five-year
9 inspection cycle, which is the inspection cycle running
10 from January 1, 2009 through December 31, 2014 ("current
11 inspection cycle"). As explained in the petition, damage
12 to Company facilities and equipment caused by Superstorm
13 Sandy reduced by 32,100 the number of underground
14 inspections that the Company would otherwise have conducted
15 through April 1, 2013 and requires that the Company
16 increase the resources allocated to the underground
17 inspection program in 2013 and 2014 in order to complete
18 all inspections by December 31, 2014. The requested
19 extension to complete the inspection program would allow
20 the Company to better allocate resources, otherwise needed
21 to meet the inspection mandate, to support other vital
22 operational needs that also require increased resources due
23 to the storm. The Commission's decision on the petition

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1 may affect the Company's projected rate year funding
2 requirement for the Structure (Inspections & Repairs)
3 program, and the Company may update its expense forecasts
4 for this program during the course of this proceeding, as
5 appropriate.

6 Q. Please describe the O&M program changes for the "Tree
7 Trimming" program.

8 A. **Tree Trimming** - In 2007, Electric Operations developed an
9 enhanced Line Clearance program that incorporated
10 appropriate risk prevention and mitigation strategies
11 designed to improve electric reliability on the Company's
12 non-network, overhead system. The principal element of
13 this enhanced program was increased vegetation clearances
14 from overhead wires along our right of way. The new
15 clearances, as outlined in Line Clearance specification E0-
16 10353, include preferred trimming of 10 foot lateral and
17 bottom clearance, with a 15 foot top clearance and an
18 alternate trim of 6 foot lateral and bottom clearance and a
19 10 foot top clearance. The scope of work was expanded to
20 include additional tree removals within the utility
21 easement, more work to reduce the brush interference with
22 the electric distribution system, and herbicidal
23 application to cut stumps.

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1 In addition, a prioritized approach to line clearance
2 was developed through a detailed examination of historical
3 overhead system vegetation-related outages. This approach
4 established a targeted circuit listing used to prioritize
5 regional tree trimming efforts. Essentially, circuits
6 indicating a relatively high likelihood of experiencing
7 tree related outages were assigned a more critical
8 placement in the line clearance queue. Conversely,
9 circuits displaying a low potential for tree-related events
10 were assigned a lower priority with a percentage of those
11 being eliminated from the immediately upcoming tree
12 trimming cycle. This prioritized approach has resulted in
13 an O&M savings of approximately \$1.5 million in RYE2014
14 compared to the historical period. For RYE2015 and
15 RYE2016, it is anticipated that line clearance work will
16 temporarily return to historical spending levels to
17 compensate for additional vegetation growth issues
18 resulting from the temporary exclusion of specific lines
19 from the clearance cycles.

20 Q. Please describe the O&M program changes for "Field
21 Operations/Unit Substations and Other O&M."

22 A. The **Field Ops/Unit SS/Other O&M** program category covers
23 inspections associated with Unit Substations including

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1 periodic inspections of station breakers, tap changes,
2 station batteries, and joint regulators. This program also
3 includes station switching and other routine work
4 activities and the cost of short cable lengths.

5 Expenditures in RYE2014 are projected to be \$925,000 lower
6 than in the historical year due a reduction in Unit
7 Substation inspection activity.

8 Q. Does this conclude your testimony regarding Electric
9 Operations' O&M program changes under Reliability in
10 Exhibit __ (IIP-6)?

11 A. Yes.

12 **VIII. Replacement Capital and O&M Expenditure Requirements**

13
14 Q. What is the next category of work you wish to discuss?

15 A. The next category of work we will discuss is the
16 "Replacement" category.

17 Q. Was the Exhibit titled, "Electric T&D - Replacement"
18 prepared under your direction?

19 A. Yes it was.

20 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-9)**

21 Q. What does Exhibit __ (IIP-9) show?

22 A. Exhibit __ (IIP-9) lists the capital program and project
23 funding requirements that support Replacement work

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1 conducted by System and Transmission Operations (S&TO),
2 Substation Operations (Transmission and Area Substations),
3 and Electric Operations (Distribution System) for the years
4 2013 through 2017. The exhibit also provides five year
5 historic spending for 2007-2011 and a 2012 end of year
6 projection for Replacement programs and projects. The
7 exhibit presents O&M program changes for Replacement. The
8 exhibit also contains "white papers" for each capital
9 program and project that provide more detailed information
10 such as: program and project work description,
11 justification, alternatives, estimated completion date,
12 current status, and forecasted funding.

13 Q. Please provide an overview of the capital programs listed
14 in Exhibit __ (IIP-9), "Electric T&D - Replacement."

15 A. Exhibit __ (IIP-9), "Electric T&D - Replacement," lists the
16 capital projects and programs that fall under the
17 "Replacement" work category. This work typically relates
18 to equipment such as burned out primary and secondary cable
19 or wire, transformers, open mains and meters, and services.
20 It usually entails replacing equipment that has failed, or
21 is likely to fail imminently. Replacement work includes
22 the cost to repair or replace primary cable sections and
23 components, and associated conduit, which fail in service.

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1 In addition, when defective components are identified on
2 the system as a result of inspection programs, depending on
3 the severity, these components may be identified as
4 candidates for replacement and scheduled for replacement as
5 soon as system conditions permit. This would include cable
6 and splice abnormalities (referred to as "C" or "D" faults)
7 or transformers that need to be taken off the system on
8 emergency for leaks and other serious defects. Some of the
9 other types of emergency response work include expenditures
10 to repair and replace: overhead poles, wire and equipment
11 that fail during emergencies and storms; underground
12 service cables (including streetlights services) and
13 associated conduit and components; secondary cable
14 sections, components, and associated conduit; and equipment
15 and transformers that fail in service.

16 Replacement work is for the most part non-
17 discretionary; when feeder cables and associated equipment
18 fail, they must be repaired or replaced as soon as possible
19 to maintain the integrity of the system. However given the
20 vast, interconnected nature of our secondary network
21 system, not all secondary cable failures work is considered
22 mandatory. In fact, this is one of the main areas in which
23 we are currently applying capital optimization analysis to

1 determine which failures are absolutely necessary to
2 resolve.

3 **A. Substation Operations Replacement**

4 **1. Substation Operations Replacement Capital Programs**
5 **and Projects**

6 Q. Does Substation Operations have any capital programs
7 related to this category?

8 A. Yes, the Failed Transformer Replacement Program and the
9 Failed Equipment Other Than Transformers Program.

10 Q. Please discuss the Failed Transformer Replacement Program.

11 A. The **Failed Transformer Replacement Program** provides funding
12 for the restoration work required to replace transformers
13 in our Area and Transmission Substations as well as
14 Generating Stations on an emergency basis.

15 Based on a historical average failure rate of 0.77%, this
16 on-going program covers the cost of replacing three failed
17 transformers (transformers, phase angle regulators and
18 reactors) per year. The funding level required for this
19 is estimated at \$22-26 million/year; 2 area station
20 transformers at \$5-\$6 million each and 1 transmission
21 station transformer at \$12-\$14 million. This cost includes
22 the installation of an existing system spare and the
23 purchase of a replacement for the utilized system spare.

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1 To quickly restore system capacity and reliability to pre-
2 failure levels, spare transformers are maintained for most
3 types of units in the system. The spare units are purchased
4 and kept on hand due to the long lead-time required for
5 delivery of a new transformer. The spare units are pre-
6 tested and partially assembled to reduce the time required
7 for replacement of a failed unit. The spare units are
8 prepared for long-term storage at the Astoria Spare
9 Transformer Yard and at other Company satellite locations.
10 The projected capital expenditures for the program vary
11 from year to year, but average \$23 million annually for
12 2013-2017.

13 Q. Please describe the Failed Equipment Other Than
14 Transformers program.

15 A. The "Failed Equipment Other Than Transformers" program
16 replaces or repairs various pieces of equipment to maintain
17 system design configuration and system reliability. This
18 program primarily covers unanticipated failures of
19 equipment such as circuit breakers, capacitor banks,
20 potheads, L&P transformers, bus, disconnect switches,
21 potential transformers, and coupling capacitor potential
22 devices in our area and transmission substations. Funding
23 is based on historical failure activity and associated

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1 spending levels. The projected capital expenditures for
2 the program are \$5.3 million annually for 2013-2017.

3 Q. Does this conclude Substation Operations' discussion of
4 this category?

5 A. Yes

6 ***B. System and Transmission Operations Replacement***

7 **1. System and Transmission Operations Replacement**
8 **Capital Programs and Projects**

9 Q. Does Transmission Operations have any similar programs
10 related to transmission cables?

11 A. Yes.

12 Q. Please describe the project titled Transmission Feeder
13 Failures shown in Exhibit (IIP-9).

14 A. The objective of the **Transmission Feeder Failures** program
15 is to provide sufficient funds for the repair of
16 transmission feeders when the repair requires a complete
17 cable section replacement between manholes or requires
18 pothead replacement. This program establishes capital
19 funding to address major transmission repairs. While
20 funding for transmission feeder repairs is generally an O&M
21 expense, the cost of extensive repairs are considered to be
22 capital and are provided for through this program. The
23 projected capital expenditures for this program are \$3

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1 million annually for 2013-2017. This funding level is based
2 on the projected average cost of one major 345kV cable
3 section replacement.

4 This failure program is a standalone program to fund
5 emergency transmission cable section replacement performed
6 by System and Transmission Operations, a Central Operations
7 organization. As discussed previously, Substation
8 Operations, also a Central Operations organization,
9 maintains two other programs to fund restoration work
10 required to replace failed transformers and other
11 components in Area and Transmission Substations on an
12 emergency basis - the Transformer Program and the Failures
13 Other Than Transformers Program. Because the three programs
14 have not simultaneously expended their full funding in any
15 year and in an effort to reduce the overall funding for
16 emergency failure repairs, we have has pooled the funding
17 for all three programs - the Failed Transformer Program,
18 the Failures other than Transformers Program, and the
19 Transmission Feeder Failures Program - and reduced the
20 total combined funding for all three by \$5 million. In the
21 event that an incident exceeds the funding for any one
22 program, funds from the other failure programs will be used
23 to fund emergency repairs.

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1 Q. Does that conclude Transmission Operations discussion of
2 this program?

3 A. Yes, it does.

4 **C. *Electric Operations Replacement***

5 **1. Electric Operations Replacement Capital Programs and**
6 **Projects**

7 Q. Please describe Electric Operations' capital Replacement
8 programs and projects identified in Exhibit (IIP-9).

9 A. The category "Replacement" in Exhibit (IIP-9) includes a
10 variety of programs projects that we will describe in our
11 following testimony. The projects and programs details are
12 included in white papers that are part of that exhibit.

13 **Primary Cable Replacement** - This program replaces primary
14 cable sections which either have failed in service or has
15 been selected for replacement before failure. These
16 repairs often involve cable replacement due to 4kV, 13kV,
17 27kV, and 33kV feeder open-autos (O/A) and transformer
18 replacements. This work often involves cable replacement,
19 cable joint replacement, related conduit work, and any
20 access requirements such as excavating in the street to
21 perform the work. Feeders that open automatically (feeder
22 open autos) as a result of cable and joint failures must be
23 repaired as soon as possible to maintain network system

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1 reliability. Feeder open-autos have a significant impact
2 in our ability to provide continuity of service to our
3 customers and thus we address every emergency primary cable
4 replacement as quickly as possible. The projected capital
5 costs for this ongoing program are \$58.2 million in 2013,
6 \$56.5 million in 2014, and \$52.3 million in 2015.

7 **Secondary Open Mains** - This program involves emergency
8 repair work on the secondary (low-voltage) network to
9 address secondary cable failures. These repairs often
10 involve cable replacement, cable joint replacement, related
11 conduit and subsurface structure work, and any access
12 requirements such as excavating in the street to perform
13 the work. Secondary open mains require repair to maintain
14 the integrity of the secondary network system according to
15 its original system design because open mains can cause
16 area low voltage conditions, outages, and additional main
17 damage due to overloads. Secondary open mains can result in
18 local contingencies within a network area load pocket by
19 limiting the load flow from transformer(s) in service and
20 increasing the load flow on the remaining main sections in
21 service. Taking no action would impact customer service
22 reliability, including restoration times and power quality
23 issues. The projected capital costs for this ongoing

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1 program are \$129.3 million in 2013, \$138.0 million in 2014,
2 and \$127.8 million in 2015.

3 **Overhead Emergency Replacement** - This program replaces
4 overhead, URD, and associated appurtenances on the non-
5 network system on an emergency basis after failure or pro-
6 active identification as part of an inspection program
7 (infrared, visual, feeder patrol, etc.) as needing
8 replacement. This work often involves cable, open wire, and
9 associated structure replacement. These high priority
10 items are crucial to meeting our customer service
11 objectives. Outages caused by damaged non-network system
12 components adversely impact the reliability and safety of
13 the system and negatively impact the SAIFI and CAIDI
14 reliability performance targets established by the PSC.
15 Whether the damage is due to age, obsolescence, or storms,
16 timely repairs are necessary to restore the system to
17 normal configuration and operation. The projected capital
18 costs for this ongoing program are \$27.4 million in 2013,
19 \$17.4 million in 2014, and \$16.1 million in 2015.

20 **Temporary Service Replacement** - Service cables and conduit
21 are the final connection between our distribution system
22 and our customers. These facilities provide our customers
23 with the electric power they require for their homes and

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businesses. At times these services fail, and we are required to replace them. When the failed service is inaccessible due to local field conditions, a temporary service connection (a shunt) is established to return service to the customer immediately. This program provides funding to remove the temporary service connection and install a permanent service cable. Depending on conditions, we may only need to replace the cable. If the existing conduit is unusable, due primarily to obstructions or size constraints, we may need to excavate to install new conduit to house the cable. The projected capital costs for this ongoing program are \$35.6 million in 2013, \$32.1 million in 2014, and \$30.9 million in 2015.

Street Light Cable Burnouts - This program replaces failed cables and associated conduit supplying service to street lights and traffic signals. Street lights and traffic signals are an important public safety concern for Con Edison, the New York City Department of Traffic (NYCDOT), and Westchester municipalities. The City and municipalities maintain these lights, patrol the lights, and collect field complaints from the public to determine which lights are not working. They then test the lights to determine if it is the City/municipality's or Con Edison's

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responsibility to make the repairs. Annually, the Company receives work requests from NYCDOT and municipalities for approximately 8,000 streetlights and traffic signals where repairs due to burnouts of Company service cables have been identified. Approximately 5,100 of these jobs require a cable replacement. The projected capital costs for this ongoing program are \$22.7 million in 2013, \$23.5 million in 2014, and \$21.8 million in 2015.

Transformer Installation – This program replaces underground-network, overhead, and URD transformers, as well as associated electrical distribution equipment and structures, such as, cable, conduit, and vaults, that are found to be defective and are removed from the system on a priority basis to maintain system reliability. Due to public safety concerns, we have instituted various programs to identify transformer equipment that could potentially fail, including a more aggressive underground transformer inspection program which includes testing for dissolved gas in oil for all units. We have also started installing remote monitoring equipment on transformers to provide real time pressure and temperature readings. Replacing failed transformers, and those that require replacement as a result of defects found during inspection, is a critical

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1 function for maintaining the integrity of the network and
2 non-network systems.

3 Our failure mitigation programs identify the
4 electrical distribution equipment on our system for which
5 removal is most urgent. These programs are designed to
6 proactively inspect our field equipment, primarily
7 underground transformers, and replace those that exhibit
8 warning signs of a potential failure to maintain public
9 safety and maintain system reliability. Since 2005, with
10 improved analysis, we have been able to dramatically reduce
11 the number of transformer failures by 81% from 2005 to
12 2011. We also achieved a 72% reduction in the number of
13 units that ruptured and failed in-service between 2005 and
14 2011. These reductions are in direct correlation to the
15 results of our failure mitigation programs. By year end
16 2011, we removed 744 units that exhibited symptoms to
17 potentially fail in-service. The projected capital costs
18 for this ongoing program are \$32.4 million in 2013, \$23.5
19 million in 2014, and \$21.8 million in 2015.

20 2. Electric Operations Replacement O&M Program Changes

21 Q. Please describe Electric Operations' O&M program changes in
22 the "Replacement" category of Exhibit (IIP-9).

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1 A. We have changes in the following programs: "Maintenance
2 Associated with Capital" (MAC), "Emergency Response",
3 "Street Lights" and "Overhead Equipment".

4 Q. Please describe the changes in the "Maintenance Associated
5 with Capital" (MAC) program.

6 A. **Maintenance Associated with Capital (MAC)** - This program
7 can be subdivided into two major components, MAC Overhead
8 (OH) and MAC Underground (UG). The MAC UG budget category
9 captures the expenses associated with the burnouts and
10 maintenance of the underground primary and secondary cable
11 systems along with their supporting conduit infrastructure.
12 The \$59,000 decrease from historical year to RYE2014 is due
13 primarily to continuing reductions in MAC UG during both
14 calendar year 2012 and RYE2014. These reductions are in
15 turn driven by a decrease in primary feeder burnouts and a
16 significant reduction in work associated with primary
17 feeder relief in 2012 and RYE2014, both major factors in
18 determining MAC UG expenses.

19 Q. Please describe the changes in the "Emergency Response"
20 program.

21 A. **Emergency Response (Burnout or Emergency Related)** - The
22 Emergency Response Budget category captures expenses
23 associated with the physical repair of cable and services

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1 damaged through insulation failure or manhole events. This
2 category also includes costs incurred in addressing fault
3 identification, local, and isolation.

4 The \$8.2 million decrease results from higher-than-
5 budgeted emergency response expenses incurred in the
6 historical year period. During that time frame, the
7 Company's service area experienced a significant heat event
8 in late July, 2011 resulting in an all-time peak demand
9 level of 13,189 MW on July 22 placing demands on the
10 underground and overhead systems beyond design levels.
11 Additionally, the Company's overhead systems were impacted
12 by Hurricane Irene in August and an unusual late October
13 snow event on the 29th of that month. Each of these events
14 required an extreme mobilization of workforce assets in
15 response to the need for rapid emergency restoration of
16 customer services. By way of illustration, the July, 2011
17 heat event caused an additional \$2.0 million in incident
18 response expenses including underground mains and services
19 and overhead services repairs.

20 Q. Please describe the changes in the "Street Lights" program.

21 A. **Street Lights** - This work item includes all work for repair
22 of existing underground and overhead street lighting wire
23 as a result of burnouts, storms, and other emergencies. It

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1 also includes the maintenance activities associated with
2 clearing obstructed street lighting service ducts and the
3 repair, disconnection, or reconnection of existing
4 underground URD street lighting wire during routine and
5 emergency conditions.

6 The \$392,000 decrease for RYE 2014 is the result of
7 plans to use the resources of the Construction Services
8 group rather than Electric Operations field forces, to
9 perform this work. Construction Services is anticipated to
10 perform the work at a lower unit cost. The costs for RYE
11 2015 and RYE 2016 are higher than RYE 2014 because they
12 reflect work being performed by Electric Operations field
13 forces. If the Construction services organization has
14 resources available to perform street light work in those
15 rate years, those resources will be utilized to reduce
16 costs where possible.

17 Q. Please describe the changes in the "Overhead Equipment"
18 program.

19 A. **Overhead Equipment** captures maintenance of overhead
20 conductors, insulators, and devices and expenses associated
21 with workforce stand-by requirements generated by
22 anticipated weather impacts on system operation. The \$1.1
23 million decrease reflects reduced workforce stand-by

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1 expense in the rate year. In anticipation of weather
2 related events having the potential of impacting system
3 operations, proactive steps are routinely implemented in
4 order to minimize restoration response time. The pre-
5 staging in stand-by mode of some portion of the workforce
6 tasked with overhead service restoration is one component
7 of this anticipatory response. As described under
8 Emergency Response program above, the Company experienced a
9 number of significant events during the historical period
10 that required an expenditure of greater resources than
11 initially budgeted for. Mobilization costs were higher
12 during the historic period than originally anticipated, and
13 the program change reflects forecast mobilization expense
14 in the rate year.

15 Q. Does the Company's forecast of storm mobilization costs
16 reflect the Company's experience related to its preparation
17 and response for Hurricane Sandy in late October and
18 November 2012?

19 Q. No. It does not. The Company's forecast reflected an
20 adjustment to historic year costs intended to reflect what
21 we believed, at that time, to be more representative of the
22 number and intensity of storms to which the Company may
23 need to respond in a typical year. The Company is

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1 assessing its experience related to Hurricane Sandy and
2 therefore re-assessing the level of storm response that
3 should be considered typical for purposes of setting rates
4 as well as the nature of the storm preparation and storm
5 response efforts that may be necessary and appropriate.
6 Accordingly, the Company plans to update its expense
7 forecasts for storm mobilization costs (as well as other
8 storm-related costs) as appropriate in its update testimony
9 in this proceeding.

10 **IX. Equipment Purchase Capital Expenditure Requirements**

11
12 Q. Was the Exhibit titled "Electric T&D - Equipment Purchases"
13 prepared under your direction?

14 A. Yes, it was.

15 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-10)**

16 Q. What does Exhibit __ (IIP-9) show?

17 A. Exhibit __ (IIP-10) lists the capital program funding
18 requirements that support Equipment Purchases by Electric
19 Operations (Distribution System) for the years 2013 through
20 2017. The exhibit also provides five year historic
21 spending for 2007-2011 and a 2012 end of year projection
22 for the Equipment Purchase programs. The exhibit also
23 contains "white papers" for each capital program that

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1 provide more detailed information such as: program
2 description, justification, alternatives, current status,
3 and forecasted funding.

4 Q. Please discuss the Company's programs for purchasing
5 transformers and meters used on the distribution system.

6 A. The **Transformer Purchase** program purchases new and/or
7 reconditioned capital electrical distribution equipment -
8 primarily underground network transformers, overhead
9 transformers, padmount transformers (including mini-pads),
10 emergency generators, and network protectors to support the
11 distribution system - to support distribution system
12 relief, reliability, emergency, and growth programs.
13 Additional details about these programs are provided in the
14 white papers for network transformer relief, overhead
15 transformer relief, transformer installation, new business
16 capital, and network reliability. The capital costs of
17 this ongoing program are projected to be \$127 million
18 annually from 2013 to 2015.

19 The **Meter Purchase** program purchases PSC-approved electric
20 revenue meters and associated metering equipment, such as
21 revenue grade instrument transformers, used for revenue
22 collection. Approximately 85,000 electric meters and

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1 associated metering equipment are required per year. The
2 capital costs of this ongoing program are projected to be
3 \$9.5 million annually in 2013 and 2014 and \$10 million in
4 2015.

5 **X. Environmental Capital Expenditure Requirements**

6

7 **A. *Environmental Sustainability Strategy***

8 Q. Please provide an overview of Con Edison Environmental
9 Sustainability Strategy

10 A. Con Edison's sustainability strategy is aligned with the
11 Company's strategic goals, and structured to allow
12 continuing development well into the next five years. These
13 six principles are:

- 14 • Con Edison will model sustainable behavior internally
- 15 • Con Edison will promote sustainable behavior to external
16 stakeholders
- 17 • Con Edison will innovate to meet customer preferences for
18 a sustainable lifestyle
- 19 • Con Edison will partner with governments to shape
20 policies and standards consistent with its sustainability
21 vision
- 22 • Con Edison will develop infrastructure to advance the use
23 and delivery of value-creating clean energy alternatives

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- Con Edison will incorporate environmental and societal values in its decision making

Con Edison fosters sustainable business practices by effectively managing corporate environmental, social, and economic programs and by measuring performance. Con Edison's sustainability vision statement specifies that we provide our customers and the public with efficient, clean, and sustainable energy, and model green behavior internally. To achieve this, we partner with stakeholders, including customers, community members, public officials, and employees, to promote and support energy efficient buildings, clean fuels, and renewable energy, along with electric-powered and alternative-energy powered transportation.

Q. Please provide an update on recent developments regarding the Company's commitment to the environment.

A. Con Edison's long-term strategy, to use our natural resources wisely while maintaining ecological balance, aims to minimize the environmental impact of operations, use resources more efficiently, and help customers reduce their own carbon footprint. The Company achieved considerable greenhouse gas emission reductions since 2010, found a new way to reuse millions of dollars worth of scrap material,

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and began providing customers with electricity from the nation's first LEED-certified substation. Additional achievements on the national level include:

- For the third straight year, Con Edison was named to the Dow Jones Sustainability Index for its financial performance, environmental initiatives, and social responsibility. Through its energy efficiency programs, the Company encourages customers to use less energy, and provides rebates for customers to use energy-efficient equipment.
- Con Edison's new Newtown substation in Long Island City, Queens earned a Leadership in Energy and Environmental Design (LEED) certification from the U.S. Green Building Council as well as a design award from the Queens Chamber of Commerce.
- Con Edison is the greenest utility Company in the United States, according to Newsweek magazine's 2011 Green Rankings. The rankings, which can be found at www.newsweek.com/green, were based on the magazine's ratings of a Company's environmental impact, environmental management and disclosure. Newsweek developed a "Green Score" for each of the 500 largest

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publicly traded companies in the United States, and Con Edison scored highest among the 30 utilities rated. The magazine calls its list the most comprehensive rankings of corporate environmental performance.

- Con Edison has earned recognition from the international Carbon Disclosure Project (CDP) for five years running for the Company's carbon emission reduction and carbon disclosure efforts. In the 2011 rankings, Con Edison placed first among utilities in the S&P 500 Carbon Disclosure Leadership Index, and was the only utility recognized in the S&P 500 Carbon Performance Leadership Index for its successful reduction of greenhouse gas emissions. The CDP, representing 551 institutional investors who manage \$71 trillion in assets, has again commended the Company for the way it discloses climate change information. Con Edison has been featured in the organization's Carbon Disclosure Leadership Index since the index was established. A key component of CDP's annual S&P 500 report, the index highlights companies that demonstrate the most professional corporate governance approach regarding revelation of

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1 climate change information. Companies are scored on
2 their climate change disclosure practices. High scores
3 indicate excellent internal data management and a
4 clear understanding of climate change issues affecting
5 the Company.

6 Q. Was the Exhibit titled "Electric T&D - Environmental"
7 prepared under your direction?

8 A. Yes, it was.

9 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-11)**

10 Q. Please describe Exhibit __ (IIP-11).

11 A. Exhibit __ (IIP-11) lists the capital program and project
12 funding requirements that support Environmental work
13 conducted by System and Transmission Operations (S&T0),
14 Substation Operations (Transmission and Area Substations),
15 and Electric Operations (Distribution System) for the years
16 2013 through 2017. The exhibit also provides five year
17 historic spending for 2007-2011 and a 2012 end of year
18 projection for Environmental programs and projects. The
19 exhibit also contains "white papers" for each capital
20 program and project that provide more detailed information
21 such as: program description, justification, alternatives,
22 current status, and forecasted funding.

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1 ***A. System and Transmission Operations Environmental***
2 ***Capital Programs and Projects***

3 Q. Please describe the Transmission Operations Capital
4 programs shown under the category of “Environmental” in
5 Exhibit (IIP-11).

6 A. There are two programs in this category – the Pipe
7 Enhancement Program and the Environmental Enhancements
8 Program. In addition to our discussion of these programs,
9 the white papers describing these System and Transmission
10 Operations Environment capital programs and projects are
11 provided in Exhibit (IIP-11).

12 The **Pipe Enhancement Program** will reduce the dielectric
13 fluid volume loss as the most suspect sections of pipe on
14 the Transmission System are proactively addressed. The
15 projected capital cost of this program is \$7.3 million in
16 2013 and \$8 million annually from 2014-2017.

17 The **Environmental Enhancement Program** also seeks to
18 mitigate the impact of leaks from our transmission feeders.
19 Leak Detection Systems are presently installed on several
20 transmission feeders with rapid circulation. Feeders with
21 slow or static dielectric fluid circulation have aged leak
22 detection alarms typically consisting of frequent pump
23 operation alarms and pressure switches that monitor loss of

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pressure. Consequently, dielectric fluid spills in these feeders may not be detected and corrected for an extended period. To reduce dielectric fluid spills into the environment, new leak detection systems are required to reduce the time required to detect, find and clamp leaks on feeders with slow or static fluid circulation. Existing systems for feeders with rapid circulation are not cost effective for such feeders. A new cost effective solution is required. Presently two research projects are addressing this problem. The Advanced Leak Detection System (ALDS) and the Neural Network Leak Detection System are in various stages of development and testing and one or both will be deployed when proven to be effective. The projected capital costs of this program are \$1 million in 2013, \$1.65 million in 2014, \$1.7 million in 2015, \$1.75 million in 2016, and \$1.75 million in 2017.

B. Substation Operations Environmental Capital Programs and Projects

Q. Please describe the Substation Operations programs listed in Exhibit (IIP-11) under "Environmental."

A. There are three programs listed under "Environmental" for Substation Operations programs in Exhibit (IIP-11). In addition to our description of these programs, the white

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1 paper exhibits describing the Substation Operations
2 environmental programs are found in Exhibit (IIP-11).

3 Q. Please describe these environmental programs.

4 A. **Environmental Health and Safety (EH&S) Risk Mitigation -**

5 This program modifies or constructs containment structures
6 around oil-filled and high-energy equipment that have been
7 identified as having failure modes with serious
8 environmental, health, and safety consequences. Effective
9 risk management is critical to good environmental
10 stewardship and the health and safety of the public and our
11 employees. Equipment in substations is evaluated for
12 potential environmental impacts and the health and safety
13 of the public and employees during normal and abnormal
14 conditions. Installation and modifications to station
15 containment and drainage systems to manage the water
16 discharges and runoff as well as potential oil releases are
17 being implemented as needed to mitigate the risks
18 identified during these evaluations. These projects are
19 also required to comply with regulatory requirements such
20 as Spill Prevention Control and Counter measures (SPCC)
21 40CFR112 and New York Department of Environmental
22 Conservation (DEC) State Pollutant Discharge Elimination
23 System (SPEDES). The projected capital cost for this

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1 program is approximately \$10.85 million annually for 2013-
2 2016, and \$5 million in 2017.

3 **Pumping/Cooling Plant Improvements** - This program consists
4 of improvements to the pumping plants and cooling plants
5 that support the Company's 69kV, 138kV, and 345kV
6 underground transmission systems. These improvements are
7 upgrades to modernize existing equipment, or they are
8 complete plant replacements if necessary. Focus is given to
9 projects that reduce environmental risk associated with
10 dielectric fluid release into the environment.

11 This program encompasses the following work scopes:

- 12 • Partial ("Skid Replacements") or complete pumping
13 plants replacements: This work consists of full
14 control panel replacements plus replacement and
15 upgrades to all hydraulic components (Pumps and
16 Ladders) in order to improve the operability of the
17 facilities. In a skid replacement, some of the
18 existing components of the original pumphouse are left
19 in place, most notably the storage tank and the
20 existing structure house the pumphouse. In a complete
21 replacement, none of the original components are left
22 in place—everything is replaced. Since skid
23 replacements are typically a lower cost alternative

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1 than a full replacement, we look to use this scope
2 where possible versus a full replacement.

- 3 • Control Panel Upgrades: The direction of the skid
4 replacement work was modified in 2010 to address
5 recent catastrophic events. In 2010, a decision was
6 made to progress to a new phase of this program in
7 order to more effectively target capital investment.
8 We took into consideration that since the inception of
9 this program, the highest priority skid replacements
10 had already been performed. We further evaluated those
11 plants remaining (approximately 75) to be refurbished
12 and determined that for the most part, the pumps and
13 ladders are in generally good condition, but the
14 control panels are in poor condition. Furthermore, a
15 root cause analysis determined that the control
16 panels, which have electrical and dielectric/
17 mechanical components residing in a common control
18 cubicle, increase the likelihood of catastrophic fire.
19 Therefore, the focus of this program has changed to
20 replacing control panels rather than skids. A cost
21 benefit analysis has shown that with this new
22 approach, we can effectively replace two control
23 panels for approximately the same cost as one skid

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replacement, thereby addressing twice as many of the more serious pump plant issues. Our current target for control panel replacements is 6 per year or 4 Control Panels and 1 Skid replacement.

- PURS Plant upgrades: This work consists of the installation of variable frequency motor drives (VFDs) for energy efficiency and reliability, replacement of existing analog controls systems with new digital systems, replacement and upgrades to hydraulic components, and installation of new communications systems.
- Cooling Plant upgrades: This work consists of replacement of existing analog controls systems with new digital systems and replacement and upgrades to hydraulic and cooling components.
- Advanced leak detection system (LDS): This work consists of the installation of systems that detect leaks on feeder pairs with great accuracy.

The projected capital cost for this program is \$3 million in 2013 and then \$5.5 million per year for 2014-2017.

PURS Supervisory Control and Data Acquisition - This project replaces the Moore analog communication system on

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all high-pressure pipe type feeders that have associated Public Utility Regulating Station (PURS) plants. The Moore system is a 40-year-old technology that is obsolete with no vendor available for replacement parts. Its performance has been steadily degrading with misoperations that shut down PURS plants which impact feeder power transfer capabilities. The new design uses the Company's CCTN network as its primary means of communications and the Verizon network for redundancy. The projected capital cost for this program is approximately \$1.05 million annually in 2013 and 2014, when the program will be completed.

C. Electric Operations Environmental Capital Programs and Projects

Q. Please describe Electric Operation's capital Environmental projects listed in Exhibit (IIP-11).

A. The category "Environmental" in Exhibit (IIP-11) includes two environmental programs that we will describe in our following testimony. The white paper describing the project is included in the exhibit.

Oil Minders - Oil minders are installed in underground vaults and manholes where sump pumps are utilized to reduce flooding in the underground structures. The oil minder was developed to prevent the pumped discharge of dielectric

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1 fluid from network type transformers into the sewer system.
2 In addition, the detection of oil spills in transformer
3 vaults is a major indicator of transformer failure. When
4 transformer troubles are addressed expeditiously, we
5 increase system reliability, quality of service, public
6 safety, and environmental security. Whenever oil is
7 encountered, the control system registers an alarm in the
8 local control room through the Remote Monitoring System
9 (RMS). This remote warning signal facilitates early
10 detection and clean up associated with leaking
11 transformers. In addition a power sensor monitors the
12 voltage supply to the pump and sends a warning signal
13 through the RMS if the oil minder and sump pump loses
14 power. This program will install approximately 350 new oil
15 minders each year at underground network transformer
16 structures. The projected capital costs of this program are
17 \$0.5 million annually from 2013-2015.

18 **The USS Site Improvement for SPCC Plans** - A comprehensive
19 investigation that focused on water vulnerability and Spill
20 Prevention Control and Countermeasures (SPCC) issues has
21 been completed for all 199 of the company's Unit
22 Substations. This program is intended to insure that the
23 existing secondary containment installations meet the

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1 minimum requirements for transformer secondary containment
2 designs as specified by EPA and NYS-DEC regulations.

3 Proposed modifications include the following items:

- 4 • Modification of the containment moats to meet the
5 minimum free board volume requirements as specified by
6 EPA.
- 7 • Installation of impervious floors in moats to prevent
8 oil spills from reaching ground water.
- 9 • Installation of control system(s) to manage
10 accumulations of rainwater in moats such as sump
11 pit(s) equipped with solidification oil systems or
12 sump pumps with oil minder devices.
- 13 • Sealing of all the cable troughs located inside
14 transformer secondary containments.
- 15 • Sealing any cracks in floors, walls, or open ends of
16 cable conduits.

17 Upon completion of this project, all the secondary
18 containment at our unit substations will be in compliance
19 with the current federal EPA and DEC-NYS regulation. Risk
20 of release of transformer oil to the environment and
21 subsequent regulatory penalties will be greatly reduced.
22 The funding forecast is \$4.8 million in 2013 and \$3.2
23 million in 2014.

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1 Q. Does that conclude your testimony regarding Environmental
2 capital programs and projects?

3 A. Yes.

4

5 **XI. Facility Renovation Capital Expenditure Requirements**

6 Q. What is the next category of work that you wish to discuss?

7 A. The next category of work we will discuss is "Facility
8 Renovation." This category relates to building and site
9 improvements that we make to non-common facilities that
10 support our electric system. It includes work such as roof
11 repairs, facility drainage upgrades, office space and
12 computer room renovations, HVAC (heating, ventilation and
13 air conditioning) projects, and the construction of new
14 facilities used to provide work space for our employees.

15 Q. Was the Exhibit titled "Electric T&D - Facility
16 Renovations" prepared under your direction?

17 A. Yes, it was.

18 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-12)**

19 Q. Please describe Exhibit - (IIP-12).

20 A. Exhibit - (IIP-12), "Electric T&D - Facility Renovations,"
21 lists the capital program and project funding requirements
22 that support Facilities Renovation work conducted by System
23 and Transmission Operations (S&TO) and Substation

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1 Operations (Transmission and Area Substations) for the
2 years 2013 through 2017. The exhibit also provides five
3 year historic spending for 2007-2011 and a 2012 end of year
4 projection for Facilities Renovation programs and projects.
5 The exhibit also contains "white papers" for each capital
6 program and project that provide more detailed information
7 such as: program and project work description,
8 justification, alternatives, estimated completion date,
9 current status, and forecasted funding.

10 **A. System and Transmission Operations Facility Renovation**
11 **Programs**

12
13 Q. Does System and Transmission Operations have any projects
14 that fall in this category?

15 A. Yes, the System Operations Computer Room Renovation
16 Projects. This project will re-design the main computer
17 room at the Energy Control Center to consolidate multiple
18 protected computer rooms into a single secured area to
19 provide more effective monitoring and easier access.
20 Control Center computer systems need to be protected and
21 redundant systems isolated to maintain a high level of
22 reliability. Before the replacement of the legacy Energy
23 Management System, main computer area space was limited and
24 computer equipment had to be located in rooms outside of

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the main computer area in order to provide the required isolation. With the replacement of both SOCCS and SOCCSX the smaller footprint of the new Energy Management System (EMS) allows us to re-locate multiple protected computer rooms into a single secured area. In addition, the existing legacy HALON systems will be replaced with a newer, approved fire suppression system for computer areas, such as FM-200 Fire Suppression Systems. The projected capital costs to complete this project are \$1 million in 2014 and \$1.5 million in 2015 to complete this upgrade.

B. Substation Operations Facility Renovation Programs

Q. Does Substation Operations have any facility renovation programs?

A. Yes, there is one. The Facility Improvement Program funds structural and yard improvements and upgrades at Substation Operations' 101 substations, as well as our nine stand alone PURS and cooling plant sites, and 3 stand alone work out locations. Structural improvements include façade, foundation, retaining wall, lifts and platforms, floors, heating and ventilation, lighting, plumbing, large scale drainage modifications, paving, fencing, and HVAC systems. This program is required to fund larger scale projects not covered by other capital programs. These projects are

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1 necessary to improve and maintain substation facilities as
2 well as to correct and upgrade numerous age-related
3 structural and facility issues in order to maintain safe
4 and reliable operation of the substations.

5 In addition, Substation Operations has various office
6 facilities that are temporary in nature, housing numerous
7 employees on a daily basis. The first alternative is to
8 relocate employees currently working in these temporary
9 locations to existing facilities, where space would have to
10 be made available and required improvements made. Where
11 sufficient space is not available, based on geographical
12 location and need, either a lease option for space or the
13 development of new space would be required as the second
14 and third alternatives. Some combination of all three
15 options may be required to most efficiently and cost-
16 effectively relocate employees to permanent facilities.
17 This program would fund improvements to existing facilities
18 or the development of new space to support these
19 relocations.

20 This program also funds a project to install backflow
21 preventers on water supplies designed to bring existing
22 substations into compliance with current cross control
23 connection device regulatory codes and requirements. As

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1 non-compliant locations are identified, a scope of work for
2 each facility is developed and a construction cost estimate
3 determined.

4 The improvements described are necessary to maintain
5 facilities in working order and in accordance with
6 applicable codes. Capital expenditures for this program
7 are projected to be \$4.5 million in 2013 and approximately
8 \$6.6 million annually for 2014-2017.

9 Q. Does this conclude your testimony in this area?

10 A. Yes.

11 **XII. Information Technology Capital Programs and Projects**

12 Q. Please explain the Company's plans to incorporate
13 technology to enhance how it manages the operation of its
14 electric transmission and distribution systems.

15 A. Our past and current methods of operation have allowed us
16 to remain the most reliable utility in the nation. We
17 continue to explore opportunities to employ the latest
18 technologies in order to streamline processes and maintain
19 reliable performance. We partner with educational
20 institutions, utilities and professional organizations to
21 develop and share knowledge gained by our exploration and
22 experience. Through technology we have improved public

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1 safety, operator performance, network reliability, and
2 efficiency. We will continue to initiate programs to
3 deliver solid performance efficiently. Our technological
4 initiatives cover a broad range of applications. Some of
5 our initiatives going forward will improve how we
6 communicate with customers during times of trouble, such as
7 storms, as well as during our normal day-to-day operations,
8 such as when they request services, to provide for higher
9 levels of customer satisfaction. Other initiatives will
10 focus on enhancing the information and analytics available
11 to our system operators and engineers for making timely
12 decisions that support system reliability possible.
13 Though individually these initiatives may have different
14 purposes, the collective objective is the same - to enable
15 our employees to judiciously leverage critical data for the
16 greatest customer benefit possible.

17 Q. I show you a document titled, "Electric T&D - Information
18 Technology" and ask whether that document was prepared
19 under your direction?

20 A. Yes, it was.

21 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-13)**

22 Q. Please describe the Exhibit __ (IIP-13).

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1 A. Exhibit __ (IIP-13) lists the capital program and project
2 funding requirements that support Information Technology
3 initiatives conducted by System and Transmission Operations
4 (S&TO), Substation Operations (Transmission and Area
5 Substations), Central Engineering, Maintenance and
6 Construction, and Electric Operations (Distribution System)
7 for the years 2013 through 2017. The exhibit also provides
8 five year historic spending for 2007-2011 and a 2012 end of
9 year projection for Information Technology programs and
10 projects. The exhibit also contains "white papers" for
11 each capital program and project that provide more detailed
12 information such as: program and project work description,
13 justification, alternatives, estimated completion date,
14 current status, and forecasted funding.

15 **A. System and Transmission Operations Information**
16 **Technology Capital Programs and Projects**
17

18 Q. Please generally discuss the System and Transmission
19 Operations "Information Technology" capital programs and
20 projects on the Exhibit (IIP-13).

21 A. System Operations is the main focal point for all operating
22 organizations within Con Edison. It operates the Energy
23 Control Center ("ECC") and the alternate Energy Control
24 Center (AECC) and controls generation, transmission and

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1 distribution. There is no room for error or delay, and
2 therefore, it is imperative that the processes and systems
3 used to manage our system provide the operators at the ECC
4 with comprehensive, accurate, and up to date information at
5 all times.

6 Q. Please continue.

7 A. **EMS Continuance ECC (EMS Reliability AECC and ECC)** - The
8 new Emergency Management System (EMS) for the transmission
9 and distribution systems must be upgraded periodically to
10 current manufacturer standards to maintain the
11 effectiveness of the new operating systems. The current EMS
12 was purchased in 2006, and the hardware does not support
13 the latest operating systems. This program will provide
14 XA21 software enhancements and the first operating system
15 and hardware replacement for the EMS. The projected
16 capital costs of this ongoing program are \$3.05 million in
17 2013, at which time a vendor software platform release and
18 hardware replacement is expected, \$0.3 million in 2014, and
19 \$0.2 million in 2015.

20 The **Distribution Orders** Enhancements Program provides
21 enhancements to the Operations Management System (OMS) used
22 by the District Operators for issuing operating orders.
23 The complexity of the transmission and distribution systems

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1 and their overlapping relationships rely heavily on
2 informed operators equipped with state of the art tools to
3 provide fast and well-informed responses to system
4 conditions. To further reduce feeder-processing time,
5 enhancements are being designed to increase electronic
6 issuance of operating orders. These enhancements include
7 new interfaces to corporate databases so that additional
8 equipment information is available to operators
9 automatically with a singular interface. District Operator
10 capability will be expanded through new tools that will
11 provide advanced visual connectivity capabilities to aid in
12 visualization of feeder and equipment changes and
13 verification of operating rules. Interfaces to field
14 operations and regional control centers will continue to be
15 expanded at the new alternate control center to provide
16 disaster recoverability at an independent site. The
17 expansion of distribution orders automation to other
18 working groups such as Overhead and Emergency groups is
19 also being planned. This work will include software
20 applications and hardware in field locations to support the
21 new functionality. The projected capital costs of this
22 ongoing program are \$0.25 million in 2013, \$0.4 million in
23 2014, and \$0.3 million annually in 2015.

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1 Q. Please summarize the remaining Information Technology
2 projects for System Operations in Exhibit ____ (IIP-13).

3 A. There are six projects with projected capital costs
4 totaling \$1.15 million in 2013, \$1.75 million in 2014, \$1.8
5 million in 2015, \$1.9 million in 2016, and \$1.55 million in
6 2017. These projects, Plant Information System, Cyber
7 Security and NERC Compliance, Operations Network for EMS,
8 System Operation Enhancements, District Operator Task
9 Managing, and Operation Management System at ECC, are
10 discussed in white papers in Exhibit ____ (IIP-13).

11 ***B. Substation Operations Information Technology Capital***
12 ***Programs and Projects***
13

14 Q. Please describe the Substation Operations Information
15 Technology initiatives.

16 A. **Technology Improvements** - The implementation and upgrade of
17 new technology is instrumental for improving efficiency and
18 reliability in Substation Operations. This program funds
19 technology improvements needed to upgrade, enhance,
20 automate, or establish Substation processes that increase
21 efficiency and improve reliability. Substation Operations
22 has established numerous procedures, instructions, and
23 guidelines for the safe operation and maintenance of
24 equipment. Numerous processes involving data/information

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collection, transfer, and storage support adherence to a governing course of action. As technology advances, the Technology Improvements program identifies and takes advantage of opportunities to improve the efficiency of these processes by implementing new tools or upgrading existing ones to enhance how data is collected, transferred, and/or stored. For example, DataSplice is work management software that works with Maximo to gather important equipment inspection and maintenance data. DataSplice provides functionality not available in Maximo and greatly enhances our ability to improve maintenance practices and track and trend equipment conditions. Customization of this software will be performed to expand functionality with the goal of improving maintenance effectiveness. The other technology improvements that will be implemented or enhanced are described in the white paper for this program. The projected capital costs of this ongoing program are \$1 million annually in 2013-2015, and \$1.1 million in 2016-2017.

C. Central Engineering Information Technology Capital Programs and Projects

Q. Please describe the Central Engineering Information Technology initiatives.

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1 **A. Project Explorer - Metaphase Replacement 2nd Phase** - This
2 project is part of a second phase initiative to update
3 Central Engineering's (CENG) document management system in
4 which supporting CENG applications will be unified under
5 the TeamCenter enterprise system. The unification of CENG
6 applications will provide reliability and process
7 efficiency to CENG's customers. In addition, the product
8 will receive equal technical support and maintenance. CENG
9 currently creates documents and tracks project information
10 through an application supported on the Project Explorer
11 (PE) platform which is an outdated operating system (early
12 1990's) that is no longer supported by Microsoft. The
13 application has been frequently displaying data delivery
14 issues and is supported by a single individual, the
15 application developer, which presents an unpredictable and
16 unreliable support. The projected capital costs of project
17 are \$1 million in 2013, \$0.5 million in 2014, and \$0.2
18 million in 2015-2017.

19 **AutoCAD Upgrade Program** - AutoCAD, consisting of various
20 specialized CAD applications, is the main drawing tools
21 used by designers throughout the operating and facility
22 departments. The CAD Project requires periodic upgrades of
23 applications and hardware to keep abreast with current

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1 technology. The current version of AutoCAD in use at the
2 Company is three versions behind the current version 2013

3 To take advantage of new technology and productivity
4 enhancements in software and hardware, the CAD system is
5 scheduled to be upgraded on over 200 workstations along
6 with upgrades to plotters, workstations, monitors, servers,
7 storage systems, scanners and peripherals. This upgrade
8 will increase productivity, maintain AutoDesk support on
9 the AutoCAD 2013 and 3D platform, and maintain file
10 compatibility. The projected capital costs of project are
11 \$0.7 million annually in 2013-2015, and \$0.8 million
12 annually in 2016-2017.

13 **Wiring Access Raceway System (WARS) Replacement** - This
14 project will replace WARS, which is stand alone (i.e. DOS
15 based), with a web-based application using current
16 technology and an Intelligent Drawing Management System.
17 WARS provides a comprehensive suite of automation tools to
18 engineer plant configuration and create the reports
19 necessary to provide the appropriate documentation required
20 for construction. WARS is also used to develop the various
21 material lists required for procurement, but there is no
22 automated integration between these documents and
23 procurement.

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1 WARS is an enterprise, text-based plant-engineering
2 tool developed and now supported by a single small
3 consulting firm over 20 years ago specifically for Con
4 Edison. WARS utilizes the APL (Array Processing Language)
5 programming language that is no longer a mainstream
6 programming language and has limited support or scalability
7 capabilities. The application resides on a server with
8 obsolete operating systems that are no longer supported by
9 Microsoft, and the server and application have, therefore,
10 been placed behind the "Ring Fence" (quarantined) for
11 protection against cyber attacks.

12 While WARS provides adequate plant engineering
13 functionality, its primary limitations lie in the
14 architecture of its legacy information and future
15 viability. It does not leverage any graphical or CAD like
16 interface to streamline the creation of design data or
17 provide the user with a more intuitive interface. Due to
18 WARS' legacy architecture, its interface is very primitive
19 and difficult for end-users accustomed to navigating more
20 modern interfaces. WARS is an essential component to an
21 integrated Information Lifecycle Management (ILM) solution.
22 However, the legacy architecture, interface, and delivery
23 mechanisms of WARS hamper the ability to leverage the

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benefits of today's leading technical capabilities, i.e., the integration with EDMS, AutoCAD, intelligent drawing management and remote web access. The projected capital costs to replace WARS are \$0.5 million annually in 2013 and 2014.

The Microfiche PDF Conversion project will create a searchable library of over 250,000 engineering documents, primarily in the form of engineering drawings, by scanning micro reproductions, also known as microfilm or microfiche (MF), and converting them to a portable document format (PDF). MF's are critical to the company's sustainability and ability to create engineering drawings. Scanning all MF will reduce or eliminate the need for physical space, enabling us to ship the MF to an off-site storage facility and secure safeguard our current inventory from malicious or accidental ruin. This conversion to searchable fields will expedite search and recovery. The projected costs for this initiative are \$250,000 in 2014 and \$200,000 in 2015.

The Digitized Equipment Manuals project will construct a digital warehouse to store an extensive catalog of equipment manuals and engineering specifications now in paper form maintained by the Equipment & Field Engineering department. Electronic access will expedite the location of

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1 required information. Security access controls can be
2 enforced more effectively, safeguarding the documents while
3 allowing the catalog to grow in an organized manner. These
4 specifications and manuals are critical to the sustainable
5 operation of engineering equipment and the safety of the
6 employees working with the equipment and the general
7 public. The projected costs for this initiative are
8 \$150,000 in 2014.

9 An **Asset Optimization** system is designed to enable a
10 company to get the most out of its investments in plant and
11 equipment by evaluating the performance and condition of
12 equipment, rather than just by its years in service. The
13 Asset Optimization project will develop a system to
14 identify, quantify, locate, and maintain the Company's
15 assets efficiently and effectively to promote equipment
16 life cycle maintenance and support. This project will
17 leverage Smart Grid processes, technologies, and
18 applications to improve today's asset management programs
19 enabling a significant improvement in the utilization of
20 both system assets and human resources. This phase of the
21 Asset Management project is for the preliminary evaluation
22 of existing programs prior to a full project development.

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1 The projected costs for this initiative are \$100,000 in
2 2015 and \$100,000 in 2016.

3 **D. Maintenance and Construction Information Technology**
4 **Capital Programs and Projects**

5
6 Q. Please describe the Maintenance and Construction
7 Information Technology initiatives in Exhibit __ (IIP-13).

8 A. We will discuss first two stand alone IT initiatives and
9 then two collections of projects that are grouped into
10 budget reference numbers. Details on all of this work can
11 be found in the "White Papers" that are contained in
12 Exhibit __ (IIP-13).

13 The **CCI Mobile Office** project has two phases. The **Mobile**
14 **Field Device Replacement Project** seeks to replace the
15 existing Mobile Field Office Tough Book devices.
16 Construction has over 200 inspectors for the field
17 verification of street excavation projects in New York
18 City. The devices are used by Constructions Inspectors at
19 the work site for access to plates, job documentation, and
20 field verification of trenching items for payment. The
21 current MFO devices are critical to operations for project
22 control, auditing, and efficient payment process. The
23 original devices were installed in 2007 and are becoming
24 less reliable with more data transmission failures. These

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1 devices will not be supported for repair in 2013. We plan
2 to start the replacement in 2013 and finish by end of year.
3 The projected cost for this work is \$325,000 in 2013.
4 The second phase, the **Construction Mobile Office Project**
5 will automate the field data collection for manhole
6 inspections and street light repairs, ultimately updating
7 the related corporate systems (Manhole Inspections and
8 Street Lights). Inspections and repairs require the
9 documentation of every aspect of the job, including
10 progress reports. Currently, this information is captured
11 in the field on paper forms, which are then filed in a
12 project book or file, or transcribed into an online data
13 storage system, in some cases, by a clerk days after the
14 notes were taken. This project will automate the data entry
15 process. Construction Services personnel will utilize the
16 computers mounted in their field vehicles to receive work
17 and document their inspections. The Construction Supervisor
18 will be able to monitor job progress and the location of
19 jobs from any computer. This project will provide
20 Construction Services field personnel access to corporate
21 applications from remote field locations. The end user will
22 be able to retrieve data related to inspections, layouts,
23 specifications, and JSSE observations. The projected costs

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1 for this project are \$500,000 annually for the years 2014-
2 2017.

3 The **Compass Rewrite Plus** will conduct a Phase 0 study to
4 determine the requirements for a replacement system for
5 Compass and to develop a new web based interface to enhance
6 the existing system. Compass is used to track items of
7 construction work performed by contractors, to initiate and
8 control procurement of contractor services and materials,
9 and to initiate and approve payments to contractors for
10 completed work for the various Construction Departments
11 (i.e. Public Improvement, Substation Construction, and
12 Construction Management). During this initiative, existing
13 business process flows, use cases, and high level user
14 requirements will be reviewed to validate Construction's
15 current and future business processes. The deliverables for
16 the Phase 0 study will include a comprehensive scope of
17 work, project cost, detail resource plan, cash flow,
18 implementation options, and project risk assessment. In
19 2013, we will complete and perform a Phase Zero Analysis to
20 determine the evolution of the Compass System. In 2014 and
21 2015, we plan to implement a new web based system to
22 streamline the use and support of the product with a more
23 efficient state of the art user-friendly interface. The

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1 projected costs of this project are \$500,000 in 2013 and in
2 2014, \$750,000 in 2015, and \$250,000 in 2016 and in 2017.

3 Q. Please explain the collections of projects that are grouped
4 together under individual budget reference numbers in
5 Exhibit __ (IIP-13).

6 A. Due to certain aspects of our accounting methods
7 procedures, there are a several projects that fall under a
8 single budget reference number, and appear as a single line
9 in our summary capital request tables. However, we wish to
10 describe the individual initiatives that make up each of
11 these groupings.

12 **Budget Reference Number PR.6XC1302** - There are a total of
13 four discrete initiatives in this collection of projects.
14 The **Upgrade and Enhance the Contractor Oversight System**
15 project will enhance our Contractor Oversight System (COS)
16 to enable the collection of more meaningful field data.
17 The Contractor Oversight System (COS), implemented in April
18 2004, is a corporate system utilized by Purchasing to
19 evaluate contractor performance. Inspectors enter field
20 observations on a contractor's performance for a given
21 purchase order. The system uses this and other input to
22 calculate a performance score and associated bid
23 multiplier. The database must be upgraded to SQL Server

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1 2008 before April 2013, which is the end of Microsoft's
2 extended support period for SQL Server 2000. After April
3 2013, Microsoft will no longer provide security updates for
4 SQL Server 2000, potentially exposing corporate data and
5 assets to security breaches which could ultimately result
6 in the system being taken offline. As COS has matured and
7 data has been collected, the business areas using the
8 system have identified several enhancements that will
9 improve their business process and ability to evaluate
10 contractors more effectively. The projected costs for this
11 initiative are \$150,000 in 2013, when this work is planned
12 to be completed.

13 The **Construction - Survey Mapping Repository project** will
14 create a repository for the electronic storage of field
15 survey data conducted by the Construction Survey Group on
16 behalf of the Company's operating organizations. The data
17 to be archived for future use include:

- 18 • Survey of Transmission Towers, Substations, and
19 Underground Transmission Feeders
- 20 • Substations Operations 3D Laser Scanning
- 21 • Distribution Engineering - Poles and Manholes

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- Gas Leaks Survey, Facilities Inventory and Aerial Photography

These data will be catalogued in an indexed repository to facilitate the retrieval of survey data across operating organizations for mapping company assets, analysis, and audits. The repository will provide a real-time, coordinate-based, visual representation of survey information and will lower reproduction costs and reduce redundant requests for information. The projected costs for this project are \$250,000 in 2013, \$500,000 annually in 2014-2015, and \$750,000 annually in 2016-2017.

The **Management Work Flow Records Retention** project will establish a document management repository using the IBM Enterprise Document Management System to implement the Law Department's Records Manager's online retention policy.

The goal of Con Edison's current records management initiative is a consistent, user-friendly, and defensible program that promotes compliance with the Company's legal and regulatory retention obligations. Construction will commit their operating documents as outlined in the Law Department's Retention Policy document into the document management repository. These documents will be versioned and controlled as per the document management configuration

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1 and retention policy. This project will support
2 Construction's compliance with the record retention policy
3 as outlined in the corporate retention policy document and
4 assist in tracking documentation for layout/project related
5 activity. This project is the final phase of records
6 retention/Iron Mountain off-site storage integration and
7 will reduce storage Iron Mountain costs. The projected
8 costs to complete this initiative are \$250,000 in 2013 and
9 \$500,000 annually for 2014-2017.

10 **Misc IT Projects - (Software Licenses - Upgrades)** is used
11 to upgrade five mini software license upgrades. These
12 license upgrades are required to maintain compatibility of
13 these software packages with existing computer hardware and
14 software, and continued vendor support for the software.
15 The following is the list of the required upgrades.

- 16 • IBM FileNet P8 Version 5.2 - This software is used by
17 Construction, Electric, Gas, Steam for the tracking of
18 Permits, Opening Tickets, Incident Reporting, Records
19 Management, and Notice of Violations. This new version
20 will access new functionality that is necessary for
21 continued support of the product, enhanced mobile field,
22 workflow, and reporting database access.

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- 1 • IBM Process Monitor provides added functionality for
2 tracking system events.
- 3 • IBM Maximo - A new versions of Maximo will include
4 enhanced reporting and visibility to our plant work
5 requests.
- 6 • Autodesk (AutoCAD) - will maintain compliance and
7 compatibility with external agencies that send us drawing
8 for potential new Public Works and Survey projects. This
9 will be crucial in our work with the Utility Data
10 Exchange.
- 11 • ESRI (ARCINFO) - The current version of this mapping
12 software for our street work coordination projects will
13 be at end of life in two years and no longer supported.
14 The new version has better web capabilities and better
15 performance.

16 The projected costs of these software license upgrades are
17 \$500,000 annually in 2014-2017.

18 **Budget Reference Number PR.6XC1304** - There are a total of
19 five discrete initiatives in this collection of projects.
20 The **Maximo Enhancements to Support Business Processes**
21 project will enhance the Maximo work management system and
22 will allow all of Construction Services to use Maximo as

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1 their work management system. Currently, the Inspection
2 group within Construction Management uses the "VanLan"
3 system, which is obsolete and will be retired. This work
4 management system will support cost effective planning,
5 scheduling, procurement, and overall work management. The
6 projected costs for this initiative are \$150,000 in 2013.
7 The **Misc IT Work Coordination Street Activity** project will
8 allow the Construction Department to bundle and view on a
9 single electronic map street work compiled from the various
10 commodity work tracking systems. The system will provide
11 an integrated view of a single job across commodities in
12 space and time including third party agencies such as City
13 projects. Users can drill down to relevant details of the
14 jobs from the source systems. Con Edison will share this
15 information with NYC Department of Transportation (DOT),
16 and DOT will provide Con Edison stipulation data and
17 resurfacing plan data. This initiative will support
18 planning and coordination across systems and commodities to
19 reduce the number of times that we need to physically open
20 any given street, reduce the total outage time, and improve
21 efficiencies in the scheduling and conduct of work. The
22 projected costs for this project are \$250,000 in 2013.

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The Misc IT CEES integration Bid Check Estimate Project

will provide a Phase 0 Analysis for a new Con Edison Estimating System to replace the Central Engineering Estimating System (CEES). The current CEES is used by Con Edison estimators to create a construction project cost estimate. The Company compares internal estimates to bids submitted by external construction companies and provides control information, allowing supervisory review of estimates in progress for various operating areas that require estimates for construction activity. The existing CEES system is a mainframe-based legacy application that was developed in 1991 with tools that are no longer supported by the vendor or IR. If the system experienced a major problem, repairing it would be difficult due to the complexity of dealing with unsupported mainframe software. The new estimating system will migrate to a more contemporary client-server, or web based environment which can be supported. The projected costs for this initiative are \$275,000 in 2013.

The Construction Services Vehicle Tracking Inspections

project will add GPS tracking hardware and software for the dispatching, tracking, and control of inspection and streetlight work in Construction Services. . In conjunction

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1 with the project roll out of new Work Management System
2 (WMS) and their mobile component, tablet computers will be
3 installed in vehicles for vehicle tracking and work
4 management. This will provide a variety of benefits:

- 5 • greater transparency to the deployment of Construction
6 Services work force and vehicles
- 7 • tracking of the units of work performed daily at a task
8 level
- 9 • reporting to assess the effectiveness of our route
10 selection, workloads and work assignment
- 11 • baseline performance assessment in the anticipation of
12 increased productivity gains.
- 13 • Dispatch of work from the WMS

14 The projected costs of this project are \$2 million annually
15 in 2014-2015.

16 The **Public Improvement Engineering System (PIES)** project
17 will add new functionality to support the Company's
18 controls over the financial and field aspects of Public
19 Improvement Interference work involving New York City
20 public works projects. This project will enhance project
21 control, transparency and reporting as it relates to city
22 projects. The system will establish:

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- 1 • a new appropriation / RAP module for real time
- 2 evaluation of Public Improvement Project funding
- 3 requests, appropriation funding levels and actual
- 4 spending levels at the project level
- 5 • a document repository for all city work as received from
- 6 the Department of Design and Construction (DDC) and
- 7 associated project documents, such as blast
- 8 notifications, notices to proceed, invoices, and
- 9 authorization approvals
- 10 • a mobile solution for data collection of actual field
- 11 activity and conditions.

12 This is integration of information will provide enhanced
13 visibility into the progression and completion of multiyear
14 public works projects. The projected costs of this project
15 are \$250,000 annually for 2014-2017.

16 Q. Do you have any further comments regarding these Central
17 Engineering and Maintenance and Construction Information
18 Technology projects?

19 A. Yes. It should be noted that these projects are part of the
20 Con Edison Common IT budget, but are presented here since
21 they typically support our electric infrastructure
22 investment.

1 ***E. Electric Operations Information Technology Capital***
2 ***Programs and Projects***
3

4 Q. Please provide an overview of the technological projects
5 that Con Edison plans on implementing in order to improve
6 the performance of its electric distribution system.

7 A. In today's world of fast paced energy demand, reliable and
8 real-time information is a key factor for reliable delivery
9 of electric power to the end-users. Operational demands
10 require a high-performance data communication network that
11 supports both existing functionalities and future
12 operational requirements. The opportunity and aim is to
13 present a structured framework utilizing effective
14 technologies to make the decision-making process more
15 effective and direct.

16 Over the past several years, the Company has implemented an
17 integrated strategy to improve the operations, design and
18 construction of the electric distribution infrastructure.
19 The Company has leveraged and implemented various advanced
20 technologies and process improvements to improve the
21 efficiency and monitoring of the distribution networks. In
22 addition, the Company continues to make significant use of
23 mobile computing and wireless technologies to improve the
24 productivity and response of its field forces.

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1 Going forward, the Company plans to continue to invest in
2 these and other advanced technologies to create a “smart
3 grid” that will facilitate improved design, construction
4 and monitoring of the electric distribution networks.

5 These technologies will continue to integrate data from
6 various sources and provide sophisticated decision-support
7 tools. In addition, the advanced technologies will provide
8 more comprehensive status information, correlate
9 performance and failure data, and drive actions that will
10 allow us to more effectively avoid and mitigate problems
11 within the distribution system. Over time, the “smart
12 grid” will also improve both our customers’ and our own
13 energy efficiency. The key advanced technology programs
14 are focused on providing enhanced information systems to
15 better support key business processes. In addition,
16 several programs are targeted to upgrading and improving
17 the underlying technology infrastructure that is used to
18 support our key processes.

19 Q. Please begin your description of Electric Operations’
20 capital “Information Technology” programs and projects.

21 A. **Work Management System** - Con Edison has maintained a suite
22 of applications that support the core work management
23 processes within Electric Operations. New applications and

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enhancements to the existing systems have introduced new technologies, enhanced functionality and improved integration among the applications that comprise the work management suite. While these systems remain viable and technically supportable, they do not provide the level of functionality that would be desirable to better facilitate the management of all aspects of work. Users also still need to access and interact with a number of systems to support work planning, execution and completion. The new Electric Operations Work Management System will provide enhancements in these areas to facilitate improved cost tracking, work scheduling, status reporting and productivity analysis.

The scope and magnitude of Electric Operations' capital construction projects and the complexities associated with its maintenance and inspection programs require new business processes, organization structure and the implementation of improved information systems to support the planning, execution and tracking of these comprehensive work programs. The new Work Management System will provide the following functionality for Electric Operations personnel:

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- 1 • A single repository for all planned and emergent work
2 within Electric Operations so users no longer need to
3 access multiple systems to process work.
- 4 • An interface that provides detailed information about
5 electric distribution assets that work is being
6 performed against.
- 7 • A comprehensive facility that helps manage all
8 maintenance and inspection programs.
- 9 • A mechanism to match project work requirements and
10 tasks to worker skills and other resources such as
11 vehicles and other equipment.
- 12 • Trending and analysis of workforce and equipment
13 performance.
- 14 • A summary of all associated costs by work activity or
15 project.
- 16 • Interfaces to Finance, Supply Chain and HR systems
17 that reduce clerical input and further streamline
18 processes.
- 19 • A resource scheduling and planning assistant.
- 20 • Integration with mobile technologies allowing the
21 transmission of data to/from the field.

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1 Deploying new work management processes, applications and
2 organization structure will result in standardization of
3 process throughout Electric Operations as well as provide
4 the ability to forecast, plan and schedule work in a more
5 efficient manner. Electronic data capture results in data
6 being entered once and seamlessly updating all systems and
7 reduces back-office administrative tasks. The projected
8 cost savings from the Work Management System are presented
9 in the white paper. Reflecting some timing adjustments due
10 to Superstorm Sandy effects, the Work Management System is
11 expected to be fully deployed by September 2014, and the
12 Company expects to realize full annualized savings in 2015.
13 The remaining projected capital costs of this project are
14 \$49.1 million in 2013 and \$10 million in 2014.

15 **Enhanced Outage Management System** - Con Edison is committed
16 to developing best practice outage restoration processes
17 and information systems. These processes and systems help
18 facilitate the correct assessment of customer outages,
19 effective restoration planning, and timely return of
20 service to customers. In the past few years, the Company
21 has made significant improvement in its ability to
22 understand the number of customers impacted by power
23 disturbances and provide customers with estimated time of

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1 restoration. These accomplishments were achieved through a
2 series of process improvements and enhancements of the
3 Outage Management suite of systems including the STAR
4 (System Trouble Analysis and Reporting) system and the
5 implementation of the Outage Location Maps on
6 www.coned.com.

7 STAR is based on Oracle's Distribution Management
8 System software suite. The Oracle product continues to be
9 one of the leading outage management software suites and is
10 utilized worldwide by many large utilities.

11 In 2012 a comprehensive review of the primary outage
12 management processes was conducted. The goal of the review
13 was to identify areas of improvement in the processes and
14 in technology. The review identified several high priority
15 improvement opportunities across all areas of the outage
16 management system process. These items, which are outlined
17 in the associated Enhanced Customer Communication Storm
18 Outage Management System white paper, will be addressed
19 starting in 2013. The projected capital costs of this
20 project are \$1.8 million in 2013, \$2 million in 2014, and
21 \$1.5 million in 2012.

22 **Energy Services Case Management** - Energy Services is
23 committed to improving the processes and information

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1 systems used to manage new business service cases. Energy
2 Services implemented the current case management system,
3 CORS (Commercial Operating Reporting System), in 1985.
4 Going forward, Energy Services will integrate a New Case
5 Management System with the new Work Management System
6 (Logica). The new Case Management System will enforce and
7 facilitate a streamlined case workflow, leverage new
8 technology and provide enhanced updates to customers and
9 contractors. In addition, the new case management tool will
10 interface with future work management systems and provide
11 improved project management capabilities that will allow
12 Energy Services personnel to better plan and achieve
13 customer service dates. The implementation of the new case
14 management system is expected to increase customer
15 satisfaction by streamlining the business process and
16 leveraging new workflow technologies and telephony
17 technologies to improve the processing of new business
18 installations in a timely manner. The new case management
19 tool will interface with future work management systems and
20 provide improved project management capabilities that will
21 allow Energy Services personnel to better plan and achieve
22 customer service dates. The new case management tool is
23 expected to provide substantial savings and cost avoidance

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1 through the automating and streamlining of processes and
2 optimized use of resources. The new system will provide
3 better information to determine more precise business
4 staffing requirements. Preliminary expected annual savings
5 are estimated at \$1.6 million. The savings will allow
6 Energy Services to reallocate FTEs to other activities,
7 reduce OT or avoid new hires for pending attritions. The
8 remaining projected capital cost of this project is \$5.1
9 million in 2013.

10 **Power Quality (PQNodes) System Upgrade** – This project will
11 provide equipment to make the Power Quality system more
12 reliable and faster. The Reactance-To-Fault (RTF)
13 application reduces fault-locating time on the primary
14 feeder system by using power quality data collected from
15 substations during feeder faults and automatically
16 indicating a fault location. This program utilizes data
17 from the existing PQNodes to calculate distances to the
18 faults based upon the reactive impedances. The project has
19 reduced fault-locating time during the summer months by
20 more than one hour. RTF is an important tool for improving
21 distribution system reliability. The upgrades to the PQ
22 system will make the RTF application more reliable.
23 This project work will include:

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- 1 • Replacement of the existing power quality loggers in forty
- 2 six (46) substations with new DataNodes
- 3 • Installation of one more node (DataNode) on a second
- 4 transformer in each station
- 5 • Enhancements of the reactance-to-fault (RTF) software /
- 6 website
- 7 • Development of an interface between the monitoring data
- 8 management / analysis system (PQView), and substation
- 9 monitors (DataNodes)
- 10 • Server upgrade

11 The projected capital cost to complete this project is \$1.6

12 million in 2013.

13 **Electric Distribution Control Center Upgrades** - This

14 project will upgrade the underlying IT server, network,

15 application and UPS infrastructure and enhance the

16 electrical and HVAC design of all four Electric

17 Distribution Control Centers to support current and future

18 demands. The operations of the Control Centers are fully

19 dependent on the computer room infrastructure which is

20 vital to maintaining our ability to deliver safe and

21 efficient services to our customers. Currently, the HVAC

22 and UPS in these facilities are not adequate, and the IT

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1 infrastructure has reached end of life. The projected
2 capital costs of this project are \$5.5 million in 2013 and
3 \$1.6 million in 2014.

4 **Contingency Analysis Program (Decision Aids)-**

5 The Contingency Analysis Program was developed as a
6 decision aid to Control Center Operators to analyze system
7 contingencies by presenting them with the most vital
8 information on current system status and next worse
9 conditions. System contingency analysis and response by
10 operators in our Control Centers is a human-intensive
11 process. Before the Contingency Analysis Program,
12 operators gathered information contained in as many as 20
13 separate applications. It was a laborious process because
14 each application requires navigation and in most cases a
15 separate login with a user ID and password.
16 Beginning in 2008, the Contingency Analysis Program (CAP)
17 has displayed for operating personnel an integrated view of
18 underground network system conditions. The application
19 allows the operators to navigate between the various
20 applications as though they are all part of a single
21 tailored application. The application facilitates the
22 processing of primary distribution feeders from outage to

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1 restoration and analyzes the network or load area
2 contingency for the "now" case and the "next worst" cases.
3 CAP was extended to the overhead auto-loop system in
4 Brooklyn/Queens, Bronx, and Westchester in 2010. In 2012,
5 we began to target the 4KV primary grid systems, as well as
6 the CAP design to include Staten Island and Westchester.
7 Currently Operators rely on several sources of information
8 (hardcopy maps, USA, High Tension, ECS, Outage Manager,
9 STAR etc) for analyzing contingencies involving the 4 KV
10 grid. There is no integrated modeling tool that summarizes
11 contingency analysis in the non-network systems. This
12 latest module to CAP will develop CAP modeling
13 functionality for the 4kv and non-network systems. The
14 projected capital costs for this project are \$0.25 million
15 annually from 2013-2015.

16 **Electronic Feeder Sign On** - Currently, the process by which
17 Con Edison workers sign on to perform feeder repair work is
18 manually-driven, involving direct two-way verbal
19 communication with the Control Center in all cases. Each
20 control center has one regional Feeder Control
21 Representative (FCR) on a shift to sign workers on
22 manually. Delays occur as crews wait their turn to sign on
23 with the single FCR and this delay can be quite

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significant. Delays are exacerbated by the interdependent nature of the work itself - downstream delays result when work is not completed on time, on shift, or in time for other work to begin on schedule. This project will allow feeder restoration tasks to be sent electronically from the FCR to a "queue" where it can be assigned by the operating supervisor to qualified personnel for work completion. This application is expected to reduce waiting time and thereby result in cost savings of about \$1.6 million. The projected capital costs for this project are \$1.2 million, \$0.450 million, and \$0.312 million in 2013, 2014, and 2015, respectively.

PQView System Upgrade - PQView is a critical component to provide automatic integration and analysis of measurements from system sensors for prognostics, diagnostics, analytics, and decision support for system restoration. For example, Con Edison currently uses PQView 3 with power quality monitors at distribution substation transformers to locate faults on its 13 and 27kV underground network feeders. PQView 3 also analyzes and provides ready access to critical operating information including fault duration, overvoltage conditions, relay targets, digital fault recorder oscillography, and smart meter data (from High

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Tension metering). However, the current PQView 3 design limitations make it a weak link in the overall goal of having greatly expanded data acquisition of grid parameters that focus on disturbance prevention and reliability improvement. Therefore, Con Edison sees a re-engineering of PQView as a critical need for a smarter, more reliable Con Edison grid. Expansion of the number of intelligent electronic devices on our systems makes the upgrade of PQView by the creation of the PQView 4 platform necessary. PQView 4's features, such as scalability, its ability to import and process data more autonomously and reliably, its greater support for various device integration standards, and its extensibility platform via a software development kit, make PQView 4 a key component to moving forward in this arena. The projected capital costs to complete this project are \$0.95 million in 2013 and \$1.2 million in 2014.

RMS Data Acquisition System - The Electric Distribution Control Centers and Engineering rely heavily on the VDAMS (RMS) data to make critical decisions on network upgrades, as well as to troubleshoot problems. The RMS/VDAMS continuously polls the underground network transformers and collects instantaneous load readings. This data, utilized with other analysis tools, provides accurate access to the

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1 underground primary (feeders) networks and enables
2 operators to quickly and accurately detect transformer
3 overloads, perform analyses, and perform next case
4 scenarios. VDAMS was introduced in the late 1980's and
5 further enhanced over the past 20 years. It has been
6 patched and modified to address additional demands from the
7 data it manages, well beyond its original intended design.
8 Changes are increasingly difficult to make within
9 reasonable time frames and the application is not efficient
10 in processing data as is currently demanded. Currently,
11 VDAMS cannot support significant technology improvements
12 which allow electric companies to take advantage of
13 "intelligent" field devices that better control and operate
14 the electric network. This program will replace VDAMS with
15 GE's XA21 SCADA Emergency Management System. The projected
16 capital cost to complete this project is \$2.4 million in
17 2013.

18 **Area Profile System** - The Company uses the Area Profile
19 System (APS) to systematically collect, assess and evaluate
20 critical population and household impact during a
21 contingency or system emergency, as required by one of the
22 Staff's recommendations in Case 06-E-0894 (LIC Outage
23 Investigation). APS identifies population and household

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1 information, and also commercial and industrial
2 information, down to specific geographic levels (e.g., zip
3 code, block group, M&S Plate) in accordance with the
4 Company's account information. APS puts this data into a
5 geographic context and provides analysis tools to enable
6 engineers and analysts to determine where best to
7 prioritize resources to achieve goals. For example, the
8 thematic mapping capability allows program managers to see
9 which areas of the service territory have greater potential
10 for energy efficiency, or which areas have the highest
11 energy efficiency savings. The system is currently
12 undergoing remediation to bring it up to Information
13 Resources' standards for supportability and maintenance. In
14 addition, the system is currently unable to provide the
15 analysis and segmentation functions needed to support the
16 planning and execution of capital deferment and demand side
17 management programs. To support the expansion in user base
18 that will result from the addition of the new data and
19 tools, APS will feature an expanded infrastructure
20 including additional production and test servers, new
21 security procedures, user and group profiles, collaboration
22 tools for users to share work among teammates and with
23 managers, and more frequent data updates. The projected

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capital costs of this project are \$0.15 million, \$0.1 million, and \$0.05 million for 2013, 2014, and 2015, respectively.

Customer Energy Management Tool - The Customer Energy Management Tool (CEMT) is an information system that supports the management of design, delivery and evaluation of a portfolio of demand side management programs and other initiatives such as energy efficiency (EE), targeted Demand-Side Management (targeted DSM) and Demand Response (DR) programs. The CEMT will be the primary program management tool, and comprise the system of record, as well as the primary source of information for demand side management (EE, DR, Targeted DSM) related regulatory reporting. The CEMT will provide business intelligence to support management and operational decisions, vendor activity, targeted marketing campaigns, and program design. The suite of features provided by CEMT will be the basis for a strong, resilient, and reliable platform to scale program activities and support the Energy Efficiency and Demand Management Department for years into the future. The projected capital cost to complete this project is \$0.190 million in 2013.

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1 **Demand Response Management System** – The Demand Response
2 Management System (DRMS) is a system that supports the
3 management of enrollment, event initiation and settlement
4 of the Company's Demand Response (DR) programs.
5 The DRMS will be the key transformational tool to support
6 the transition from prior relatively rudimentary DR product
7 offerings to the need to manage a portfolio of complex
8 offerings with ever increasing customer participation. The
9 Company has recently, over the past two years, expanded
10 from a commercial and residential contingency event program
11 to having contingency and peak-shaving programs, and to
12 expanding the residential market from only central air
13 conditioning to include room air conditioning offerings.
14 While the MW enrollment has grown by over 10% for each of
15 the past two years, we expect a considerable customer
16 increase with the deployment of 10,000 room air
17 conditioning controllers (ModLet) in 2012.
18 DRMS implementation will bring a significant set of
19 benefits to Con Edison and greatly assist in the operation,
20 marketing, and evaluation of Con Edison's portfolio of DR
21 programs which have a collective annual budget of more than
22 \$15 million.

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1 The benefits will be in the areas of reducing program and
2 departmental operating cost and the improved efficiency of
3 the department. The projected capital costs for this
4 project are \$2.25 million in 2013 and \$0.7 million in 2014.

5 **SCN Replacement** - This project plans to upgrade 205 Station
6 Control Node (SCN) data concentrators in our unit
7 substations with more advanced NTX data concentrators which
8 will be able to communicate using multiple protocols.

9 Currently 205 out of our 239 unit substations use SCN data
10 concentrators that use an outdated communications protocol
11 not compatible with the current DNP standard protocol
12 widely used by other utilities and the standard protocol
13 for other Con Edison supervisory control systems.

14 The plan is to replace the 205 SCN data concentrators in
15 two phases over 5 years as follows:

16 Phase I: this phase will include developing a prototype
17 data concentrator and replacing the first 20 units.

18 Phase II: upon successful completion of Phase I,
19 Distribution Engineering and Tech services will start
20 ordering and replacing 186 data concentrator.

21 This funding request is for Phase I of the project which
22 will replace 20 of the 205 SCN data concentrators. Capital

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costs for this phase are projected to be \$0.92 million in 2013.

System Enhancements to Support Conservation Voltage

Optimization - Con Edison recently conducted a pilot program designed to gain experience in operating the network distribution system in a Conservation Voltage Optimization mode to reduce real and reactive energy consumed by customers, decrease demand and improve customer voltage regulation. The CVO pilot was implemented in eleven (11) area substations and thirteen (13) networks.

In order to properly regulate customer voltage via CVO, our systems must be able to identify times when the voltage regulation is out of specification so that these excursions can be tracked down, and the root causes identified and corrected.

This funding request provides for the development of software tools, procurement and installation of equipment to utilize new control chart metrics for quantifying the impact of our normal scheduled voltage on customer equipment, along with energy savings that result from optimizing the delivered voltage. The scope of work encompasses enhancements to the following systems:

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- Deployment of statistical process control systems for area substation voltage regulation and other automated reporting systems
- Installation of end of line monitors in the secondary distribution network and overhead system. Data supplied by these monitors and process control systems are necessary to assure proper delivery voltage to our customers.

The projected capital cost for this program is \$0.5 million in 2013.

Emerging IT Project Initiative for Enhanced Distribution

System Analysis - This project provides funding for information technology projects that provide enhancements to our underground and overhead operations. Projects include advanced decision analysis for operators, risk and reliability analytical tools and predictive tools to assist in system operation during contingencies. Capital expenditures for this program are forecast to be \$1.9 million in 2013, \$2.55 million in 2014, \$4.8 million in 2016 and \$4.0 million in 2017.

1

2 **XIII. Municipal Infrastructure Investment Capital Expenditure**
3 **Requirements**

4
5 Q. Was the Exhibit titled "Electric T&D - Municipal
6 Infrastructure Support" prepared under your direction?

7 A. Yes, it was.

8 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-14)**

9 Q. Please describe Exhibit __ (IIP-14), "Electric T&D -
10 Municipal Infrastructure Support".

11 A. Exhibit __ (IIP-14) lists the capital program and project
12 funding requirements for Municipal Infrastructure Support
13 work conducted by Electric Operations (Distribution System)
14 for the years 2013 through 2017. The exhibit also provides
15 five year historic spending for 2007-2011 and a 2012 end of
16 year projection for Municipal Infrastructure Support
17 programs and projects. The exhibit also contains a "white
18 papers" for the Municipal Infrastructure Support program
19 that provides more detailed information such as: program
20 and project work description, justification, alternatives,
21 estimated completion date, current status, and forecasted
22 funding. The Municipal Infrastructure Support program will
23 be addressed by the Municipal Infrastructure Support Panel.

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1 The projected capital costs for Municipal Infrastructure
2 Support are \$70.9 million in 2013, \$69.3 million in 2014,
3 \$63.7 million in 2015, \$60.6 million in 2016, and \$54.6
4 million in 2017.

5 **XIV. Capital and O&M Summary Information**

6
7 Q. Was the document titled "Infrastructure and Operations
8 Panel Capital and O&M Summary" prepared under your
9 direction or supervision?

10 A. Yes.

11 **Mark for Identification as Exhibit __ IIP-15**

12 Q. What does this document show?

13 A. This document presents an overall summary of the total
14 Capital expenditures that have been discussed in our
15 testimony. Initially, a total summary of each
16 organization's capital spending by category is presented.
17 Then individual tables are presented for each organization,
18 showing each project and program by category. The exhibit
19 also presents a summary of the Company's historic and
20 projected annual O&M expenditures from 2007 through 2017.

21 Q. Does this conclude your presentation of the projects and
22 programs that make up the Infrastructure and Operations
23 Panel's capital and O&M funding requests?

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1 A. Yes.

2 Q. Is there anything else that you would like to note
3 regarding the Company's T&D infrastructure investment
4 program?

5 A. Yes, we wish to recognize the Company's Infrastructure
6 Investment team which has been successfully meeting
7 challenges, creating opportunities and taking actions that
8 will improve the reliability and viability of our
9 infrastructure long after this rate year has ended. We are
10 planners, engineers, designers, constructors, operators and
11 maintainers of energy infrastructure providing reliable
12 electricity to millions of customers. We maintain the
13 systems and are the first responders to events. Our
14 investments in our people and our infrastructure are
15 integral to our operational strength. We are a mutually
16 supporting cross-functional organization working together
17 with municipal government and the Department of Public
18 Service as part of the public infrastructure that is
19 absolutely necessary to support the economic growth of Con
20 Edison's service area.

21 **XV. Reconciliation and Reporting of Capital Expenditures**

22

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1 Q. What is the Company's position regarding continuation of
2 the one-way downward-only reconciliation of T&D, Electric
3 Production, Shared Services, and Municipal Infrastructure
4 support capital expenditures?

5 A. Company witness Muccilo addresses the reconciliation of
6 these capital expenses. Mr. Muccilo also addresses
7 continuation of capital reporting requirements and
8 expiration of the capital spending target mechanism.

9 Q. Does the Company propose to report on capital expenditures?

10 A. Yes. Currently, the Company is subject to three separate
11 annual capital-reporting filing protocols. The Company
12 proposes to consolidate its capital reporting filings. As
13 established by Staff Recommendation IV-2 in Case 99-E-0930
14 (Washington Heights Network Outage Investigation
15 proceeding), the Company reports annually to the Commission
16 on its capital and operations and maintenance expenditures
17 for electric distribution and substation operations. As
18 established by Staff recommendation 80 in Case 06-E-0894
19 (Long Island City Outage Investigation), the Company files
20 its five-year electric capital budget with the Commission
21 by March 1 each year. In addition, the Company's recent
22 electric rate plans have required annual filing of electric
23 capital budgets and expenditure reports.

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1 The Company proposes to file a single electric capital
2 budget and expenditure report annually. The Company
3 proposes to file the following information with the
4 Commission by February 28, 2015:

- 5 • A five-year (2015-2019) capital budget for electric
6 transmission, substations and distribution operations,
7 electric production, municipal infrastructure, and
8 shared services.
- 9 • a report on capital expenditures in the above
10 categories during each of the two calendar years
11 spanning the rate year ending September 30, 2014,
12 i.e., calendar years 2013 and 2014. (The Company
13 establishes its capital budgets on a calendar-year
14 basis, and calendar year reporting is consistent with
15 the Company's budget and expenditure tracking
16 process.)

17 To provide a point of comparison for the report on 2013 and
18 2014 capital expenditures, within 30 days of the
19 Commission's order establishing rates in this proceeding,
20 the Company would file a comprehensive listing of all
21 capital projects and programs with associated projected
22 expenditures for 2013 and 2014, that in total constitute

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the capital expenditures authorized in the Commission's order ("Project/Program List"). The February 28, 2015 report would identify changes from the capital programs and projects and associated expenditure levels identified in the Project/Program List. These changes include projects and programs that were eliminated or added with supporting explanations and actual amounts spent. The February 28, 2015 report would provide details and explanations regarding expenditure variations greater than 15 percent above or below the expenditure levels stated in the Project/Program List for all programs and programs with a forecast cost of \$5 million or more up to \$25 million and expenditure variations greater than 10 percent above or below for programs and projects with a forecast cost of \$25 million or more. The Company would file a capital expenditure report by February 28 of each year thereafter until electric base delivery service rates are changed by the Commission. The annual reporting requirements established in Cases 99-E-0930 and 06-E-0894 would be discontinued.

XVI. Smart Grid Stimulus Project Costs

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1 Q. Has the Company reported to the DPS Staff regarding the
2 status and costs of its ongoing Smart Grid projects that
3 are partially funded by grants from the United States
4 Department of Energy?

5 A. In its *Order Authorizing Recovery of Costs Associated with*
6 *Stimulus Projects*, issued July 27, 2009 in Case 09-E-0310,
7 p. 58, the Public Service Commission stated, "We expect the
8 Staff to review the reasonableness of the amounts spent on
9 each project no later than the first rate case in which the
10 utility seeks to place the project into rate base." To
11 facilitate Staff's review of project costs the Commission
12 directed all utilities receiving Smart Grid Investment
13 Grants ("SGIG") and Smart Grid Demonstration Grants
14 ("SGDG") from the United States Department of Energy (DOE)
15 "to submit quarterly reports to the Director of the Office
16 of Electric, Gas and Water detailing the project
17 milestones, including which milestones have been reached,
18 the associated costs for each project milestone as well as
19 documentation supporting the associated costs (e.g., vendor
20 invoices)." To date, the Company has submitted to DPS
21 Staff ten quarterly reports on its SGIG and SGDG projects,
22 with the most recent report transmitted on October 26,
23 2012.

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1 Q. Is the Company presenting any project cost information in
2 the present rate case proceeding?

3 A. The Commission's July 27, 2009 order states,

4 In addition, although we approve in this Order
5 the projects that are being proposed by the
6 utilities, we retain the right to review the
7 reasonableness of the costs associated with each
8 project, prior to or at the time of the utility's
9 next rate case when the projects are considered
10 for inclusion in rate base. At such time, the
11 utilities are required to file evidence
12 demonstrating the reasonableness of costs
13 associated with each project
14

15 The Company's Accounting Panel proposes to include in rate
16 base Smart Grid project costs through June 30, 2012 and has
17 reflected the associated carrying costs in the revenue
18 requirement. The Company is proposing to include in rate
19 base the costs of the following SGIG projects:

- 20 • Enhanced SCADA System
- 21 • Intelligent Underground Automatic Loop
- 22 • Overhead Distribution Sectionalizing Switches
- 23 • Underground Distribution Sectionalizing Switches
- 24 • Remote Monitoring System Upgrade
- 25 • High Tension Monitoring and Data Acquisition System
- 26 • 4kV Grid Modernization
- 27 • Dynamic Modeling & Simulation
- 28 • Vault Data Acquisition System

29 In support of the inclusion of these costs in rate
30 base, we are providing a document titled "Smart Grid
31 Deployment Project Outline." This document consists of a

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1 description of each of the projects for which the Company
2 proposes to include costs in rate base, the budget of each
3 project, and the benefits provided by each project.

4 **MARK FOR IDENTIFICATION AS EXHIBIT __ (IIP-16)**

5 Q. Has the Company reported any technical performance benefits
6 for smart grid projects?

7 A. Yes, the Company reports technical performance to the
8 Department of Energy and Public Service Commission on a
9 quarterly basis. The performance metrics includes reports
10 on the number of units installed as well as the reliability
11 and energy efficiency benefits of these investments on the
12 affected electric distribution circuits.

13 **XVII. Reliability Performance Mechanism**

14
15 Q. Does the Company seek modification of any of the
16 performance metrics of current Reliability Performance
17 Mechanisms?

18 A. Yes, we propose two modifications to the current
19 Reliability Performance Mechanism (RPM). First, we propose
20 to end the performance metric for replacement of over-duty
21 circuit breakers. Second, we propose to exclude from
22 measures of outage frequency and duration outages caused by

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1 the impact of major storms on the overhead facilities
2 supplied from the network system.

3 Q. Please describe the performance metric for replacement of
4 over-duty circuit breakers.

5 A. Since 2003, Con Edison has been required to perform
6 retrofits of over-duty 13kV and 27kV breakers at a rate of
7 at least 60 units per year, subject to revenue adjustment
8 of \$100,000 per breaker less than the minimum with a \$3
9 million cap. This requirement resulted from concerns the
10 DG community brought to the Commission, as the over-duty
11 condition was cited as a barrier to their connection to the
12 Con Edison distribution system. The Company has never
13 missed the annual target.

14 Q. Please discuss your proposal to end the performance metric
15 for replacement of over-duty circuit breakers.

16 A. In 2003, approximately 2,000 circuit breakers,
17 located in 45 of 62 area substations were over-dutied.
18 Since the performance mechanism commenced, we have
19 completed retrofits on approximately 800 (40%) of these
20 breakers – equating to a rate of approximately 80 breakers
21 per year. Sixteen stations have been completed, 11 are
22 currently in progress, and 18 have not yet been initiated.
23 If we moved forward at a rate of the 60 unit per year

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1 mandate, it would take approximately 20 additional years to
2 work complete the original population of 2,000 breakers.
3 Over the past several years, technologies, such as fast-
4 acting fuse devices and inverter interconnections, have
5 become commercially available to DG operators to negate the
6 contribution of DG generation to fault currents. Because
7 of these technologies, over-dutied breakers are no longer a
8 barrier to the interconnection of DG to the Company's
9 distribution system. And we believe that the major impetus
10 for establishing the breaker replacement performance
11 mechanism has dissipated.

12 Q. Does the Company intend to continue its program for
13 replacing over-dutied circuit breakers?

14 A. Yes. As we discussed earlier in our testimony, the Company
15 proposes to spend \$11.28 million in 2013, \$11.3 million in
16 2014, \$10.5 million in 2015, and \$10 million annually in
17 2016 and 2017 to replace over-dutied breakers at a rate of
18 about 60 to 65 units per year.

19 Q. Why is the Company proposing that the over-dutied breaker
20 metric be ended?

21 A. The performance mechanism should be ended because over-duty
22 condition should no longer be viewed as a barrier to DG
23 connection as new, proven technology has provided a better

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1 solution than retrofitting breakers. The metric need not
2 and should not go on for another twenty years until all
3 breakers are replaced. The replacement program should be
4 implemented similarly to the Company's other long-term
5 capital equipment replacement programs where the Company
6 has to carefully weigh risks and benefits in the allocation
7 of limited resources.

8 Q. Does the 60-breaker annual removal target present concerns
9 for the effective implementation of the replacement
10 program?

11 A. Yes, it does. While the replacement of 60 breakers "on
12 average" annually is fully consistent with the goals of the
13 Company's program, the performance mechanism reduces the
14 Company's flexibility to meet these goals in a more optimal
15 manner. Thus, the Company might be able to implement
16 removals with a better focus on factors such as degree of
17 over-duty, breaker age, failure history, obsolescence,
18 degree of over-duty, and interrupting technology. A rigid-
19 end-of-the-year target can negatively influence efficient
20 planning of work including the service outages needed to
21 performance the replacements.

22 Q. Please discuss your proposal to exclude from measures of
23 outage frequency and duration outages caused by the impact

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1 of major storms on the overhead facilities supplied from
2 the network system.

3 A. The RPM contains four categories exclusions applicable to
4 operating performance. The categories address major
5 storms, generation or bulk transmission incidents,
6 incidents resulting from strikes or a catastrophic event
7 beyond the Company's control, and outages beyond the
8 Company's control. We are proposing to modify the
9 exclusion for major storms which currently provides for the
10 exclusion of:

11 Any outages resulting from a major storm, as
12 defined in 16 NYCRR Part 97 (i.e., at least 10%
13 of the customers interrupted within an operating
14 area or customers out-of-service for at least 24
15 hours), except as otherwise noted; this includes
16 secondary network interruptions that occur in an
17 operating area during winter snow/ice events that
18 meet the 16 NYCRR Part 97 definition.
19

20 We propose to modify the "major storm" exclusion to state
21 the exclusion "includes interruptions to customers in
22 secondary network areas who are supplied via overhead lines
23 connected to an underground network system."

24 Q. What are the reasons supporting your proposal?

25 A. In areas of Con Edison's distribution system, customers are
26 supplied from overhead secondary mains and services that
27 are energized from the secondary network distribution

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1 system (overhead network customers). In these areas,
2 underground network transformers connect to cable risers on
3 poles and supply an overhead distribution system of
4 secondary mains and services. Like equipment on the non-
5 network radial system, poles, overhead mains, and overhead
6 services supplied from the secondary network system are
7 subject to storm damage, and when such storm damage causes
8 customer outages, the outages are considered secondary
9 network outages and affect the Company's RPM performance
10 under the Network Outages per 1,000 Customers and the
11 Network Average Outage Duration threshold standards. We
12 are proposing that interruptions to overhead network
13 customers caused by major storms be excluded in determining
14 the Company's performance under these threshold standards.

15 Q. Does the exclusion as currently written exclude
16 interruptions to overhead network customers caused by major
17 storms?

18 A. The exclusion applies to "any outages resulting from a
19 major storm" and does not distinguish between outages
20 affecting the non-network radial system and outage
21 affecting the network system. Therefore, we believe that
22 the exclusion as currently written excludes interruptions
23 to overhead network customers caused by major storms.

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1 However, we recognize that the exclusion has historically
2 been applied only to major storms affecting the non-network
3 radial system. And, for that reason, the Company sought
4 and received the Commission's approval to exclude
5 interruptions to overhead network customers caused by major
6 storms in 2010 and in 2011. The Commission approved the
7 exclusion of interruptions to overhead network customers
8 for the March 13, 2010 Nor'easter with tropical storm force
9 winds (75 MPH in the Queens network area) that interrupted
10 174,800 customers and for the September 16, 2010 tornados
11 and macro-burst in Queens and Brooklyn. The Commission
12 also approved the exclusion of interruptions to overhead
13 network customers for Hurricane Irene on August 8, 2011.
14 For Hurricane Irene the Commission stated, "Hurricane Irene
15 met the criteria of the major storm exclusion as Con Edison
16 asserts because the electrical service received by the
17 affected network customers is dependent on overhead lines
18 and the affected customers were out of service for more
19 than 24 hours."

20 Q. Why then does the Company propose to specifically exclude
21 interruptions to overhead network customers caused by major
22 storms?

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1 A. The text of the exclusion should be clarified consistent
2 with recent Commission pronouncements that the major storm
3 exclusion applies to the portions of the network system
4 supplied from overhead facilities.

5 **XVIII. Distributed Generation**

6
7 Q. Let's turn our attention to the issue of Distributed
8 Generation or DG. Please describe the Company's overall
9 view of DG.

10 A. Con Edison's goal is to work with regulators, existing and
11 interested DG customers, and DG stakeholders to help
12 provide cost-effective energy options while at the same
13 time assuring that non-DG customers are not subsidizing DG
14 customers.

15 Q. Please explain subsidization.

16 A. We want to be sure that DG customers pay for the
17 infrastructure that supports their needs without shifting
18 any of those costs to other customers.

19 Q. Can you describe the Company's current efforts with regard
20 to DG?

21 A. Yes. The Company's DG efforts are focused on the
22 following: (1) ongoing interconnection process
23 improvements and coordination with DOB and NYSERDA;(2)

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1 integrating DG into load forecasting, planning, and
2 operations; (3) implementing the new offset tariff for
3 campus-style customers, and (4) integrating DG across the
4 Company's three commodities.

5 Q. Are there any other DG efforts?

6 A. Overall, we are trying to improve our role in the public
7 discussion regarding DG. By that we mean that the Company
8 is trying to anticipate DG issues as well as to communicate
9 clearly and consistently. Since 2005, the Company's DG
10 Ombudspersons have worked to identify and address DG issues
11 and to communicate with the DG community through one-to-one
12 communication, responding to direct queries as well as
13 participating and initiating public events, management of
14 the DG webpage, and social media. For example, the Company
15 recently held a three-day Combined Heat and Power
16 Interconnection Seminar on October 15-17, attended by more
17 than 40 system installers, and an October 1st event,
18 organized with NYSERDA and CUNY, attended by 24 solar
19 installation companies and more than 350 building owners.
20 The role of the DG Ombudsperson has recently expanded
21 beyond outreach to include more focus on ongoing internal
22 process improvements and tariff development. For instance,

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1 the Company is continuing to expand its electronic
2 application processes.

3 Q. Returning to the four areas described above, please explain
4 what you mean by integrating DG into load forecasting,
5 planning, and operations.

6 A. The number of DG installations continues to grow.
7 Currently there is about 150 MW of baseload DG installed in
8 our service area with 75 MW of new installations
9 anticipated by 2017. By 2030, we estimate there may be 500
10 MW of installed DG. Included in the Company's portfolio
11 approach to infrastructure investment and infrastructure
12 project deferral are anticipated energy efficiency, demand
13 response, voltage conservation, power factor improvements,
14 and customer-sited DG. Currently Customers' DG is used in
15 planning at the area substation level. Unlike other
16 demand-side measures, such as energy efficiency, the DG
17 capacity does not provide a benefit at the distribution-
18 system level as we must provide Standby power to the DG
19 customer. To address this, operating protocols adhering to
20 substation design criteria are being put in to place to
21 meet load under circumstances where DG units included in
22 the load relief plan are out of service on peak summer
23 days. Telemetry installed on these DGs informs any need

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1 there may be for these operational contingency plans, which
2 will include measures such as customer appeals for load
3 reduction, emergency demand response, and the use of
4 customers' emergency generation or company-owned emergency
5 mobile generation. As more DG larger than 2 MW is
6 installed, potential T&D benefits should increase towards
7 2030. DG will play a role, alongside energy efficiency and
8 demand response, in realizing savings going forward.

9 Q. Can you address the intersection between energy efficiency
10 and DG?

11 A. DG should be well positioned to offer customer-sited
12 reductions alongside measures such as demand response and
13 energy efficiency. In short, we are considering a portfolio
14 approach where reliable DG will be one of multiple options
15 for achieving load reductions and deferring costly
16 traditional load relief. Thus, we are exploring the
17 following with Energy Efficiency: (1) risks such as
18 emissions, reliability, and commissioning problems, (2)
19 technological potential, feasibility, economic, and
20 delivery options, and (3) coordination with NYSERDA on new
21 "modular CHP" program and to align additional CHP
22 incentives with target electric networks—similar to
23 existing Solar Empowerment Zones identified by the

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1 utilities as locations where solar might help defer capital
2 investment. In addition, we have incorporated oil-to-CHP
3 into Integrated Long Range Planning. DG can be part of the
4 decisions customers are making now, and adding it to the
5 Company's many options for achieving load reductions will
6 help us move towards a more probabilistic, multi-solution
7 approach to capital planning and infrastructure avoidance.

8 Q. You also mentioned implementation of the new offset tariff.
9 Can you explain?

10 A. This new tariff, just approved by the PSC in October in
11 Case 11-E-0299, will allow DG customers with campus-style
12 settings to interconnect their generation to the Company's
13 high-tension system and have their generator's export
14 allocated to their other accounts at the premises.

15 Q. Please explain the cross-commodity considerations you
16 mentioned.

17 A. The Company recognizes that DG has the potential to
18 influence electric load growth by influencing energy mix
19 for new development. New DG customers, including oil-to-
20 gas/CHP conversions will create new gas revenue. On the
21 Steam side, the Company is exploring customer-side steam
22 supply through a pilot program. The needs of the steam

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1 system must be coordinated with gas and electric to avoid
2 acting at cross purposes.

3 **XIX. Standby Service Contract Demand**

4
5 Q. What is the next topic of your testimony?

6 A. We will present the Company's proposal to modify the method
7 by which Contract Demand for customers taking standby
8 service is established.

9 Q. Have you prepared an exhibit in conjunction with this
10 proposal?

11 A. Yes, we have prepared an exhibit titled "Standby Rates
12 Illustration."

13 **MARK FOR IDENTIFICATION AS Exhibit __ (IIP-17)**

14 Q. Please briefly describe the function of Standby rates.

15 A. Standby rates establish the charges to back up and provide
16 service to customers who normally supply their own energy
17 needs by self-generation with Distributed Generation ("DG")
18 or Combined Heat and Power ("CHP"). These rates provide
19 for cost recovery through two primary charges: Daily As-
20 Used Demand and Contract Demand.

21 Q. What are the roles of Contract Demand and Daily As-Used
22 Demand in Standby rates?

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1 A. After a lengthy proceeding, the Commission established
2 these two primary components of Standby rates so that the
3 Company costs incurred to provide service to the customer
4 installing DG are not subsidized by other customers. In
5 other words, the Standby rates prevent subsidization of the
6 costs to supply back-up power from the grid for distributed
7 generation by customers without distributed generation.
8 The Contract Demand charge is designed to recover the costs
9 for the local system needed to deliver the DG customer's
10 highest potential kW need. The Contract Demand charge is a
11 fixed charge. The Daily As-Used Demand Charge is designed
12 to recover the costs of the shared system upstream of the
13 DG customer. The Daily As-Used Demand charge is a variable
14 charge based on daily peak kW measurements for each
15 relevant time period. Exhibit ____ (IPP-17), page 1,
16 illustrates the upstream costs recovered by the Daily As-
17 Used Demand charge and provides an example of Daily As-Used
18 Demand determination.

19 Q. How is the Contract Demand amount determined and may the
20 amount change?

21 A. Under the current tariff, either the customer or Con Edison
22 may set the Contract Demand. If a customer's measured peak
23 demand exceeds the Contract Demand, the Contract Demand is

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1 increased to the new peak. If the exceeded Contract Demand
2 was originally set by the customer, the customer may also
3 face an exceedance kW surcharge. Whether there is an
4 exceedance surcharge and the amount of a surcharge depends
5 upon the amount of the exceedance. Exhibit ____ (IPP-17),
6 page 2, illustrates the local costs that the Contract
7 Demand is designed to recover and gives an example of a
8 Contract Demand exceedance.

9 Q. Are there other circumstances under which the amount of the
10 Contract Demand can change?

11 A. Yes. Under the current tariff, a customer may revise the
12 Contract Demand upward at any time. A customer may revise
13 the Contract Demand downward once every twelve months but
14 the Contract Demand may not be set at a level that is lower
15 than the highest demand reached in the past twelve months
16 unless the customer demonstrates, based on an engineering
17 analysis submitted to the Company, that electricity-
18 consuming equipment has been removed or abandoned in place
19 or that permanent energy-efficiency or load-limiting
20 equipment has been installed.

21 Q. What has been the Company's experience regarding the
22 determination of the Contract Demand under the Standby
23 rates?

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1 A. We have encountered some instances of customers setting a
2 Contract Demand below what we believe to be the parameters
3 of cost recovery established by the Commission. The result
4 is that other customers pick up the costs of equipment
5 meant to fully supply the Standby customer. When customers
6 have elected to have the Contract Demands determined by Con
7 Edison in accordance with the tariff, this has not been an
8 issue as the rates properly recovered costs for DG
9 customers without subsidization.

10 Q. The current tariff provides that the Contract Demand is
11 reset in conformance with any exceedance regardless of
12 whether the customer or the Company had set the Contract
13 Demand. Why does that provision fail to prevent the
14 subsidization?

15 A. Over time exceedances and the ratcheting up of the Contract
16 Demand can have the effect of incrementally adjusting the
17 Contract Demand to approach the customer's maximum
18 potential demand. The problem is that Con Edison has
19 installed and maintains infrastructure to meet the
20 customer's maximum potential demand from the first day that
21 the customer's service was installed and the Company's
22 maintenance continues after the Customer's DG is operating
23 takes Standby rates. If the Contract Demand is not set

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1 properly at the outset, other non-DG customers will bear
2 the cost for that investment. We also emphasize that
3 because the Company may need to meet the customer's maximum
4 potential demand, notwithstanding the level of a DG
5 customer-set demand, for planning purposes, the Company
6 must reserve that demand on the use of its system and may
7 not use that infrastructure to meet the demands of other
8 customers.

9 Q. What change is Con Edison proposing in how Contract Demand
10 is determined?

11 A. Con Edison proposes that the basis for the Contract Demand
12 for each Standby account be the maximum potential demand on
13 the Company's system to serve that customer's account as
14 described below. If the Customer establishes the Contract
15 Demand for the account, the Company would have the final
16 authority to approve or modify that Contract Demand. In
17 that circumstance, the Company further proposes that no
18 surcharges would be assessed if the customer exceeds the
19 Contract Demand.

20 Q. Are there circumstances under which the Contract Demand as
21 set through the Company's proposal could be lowered?

22 A. Yes. The Company recommends the continuation of the
23 opportunity to reduce the Contract Demand once every twelve

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1 months if the customer demonstrates, based on engineering
2 analysis, submitted to the Company, that electricity-
3 consuming equipment has been removed or abandoned in place
4 or that permanent energy-efficiency or load-limiting
5 equipment has been installed. The current tariff states
6 that the Contract Demand may not be set at a level that is
7 lower than the highest demand reached in the last twelve
8 months unless the customer demonstrates the foregoing
9 permanent changes. The Company recommends deletion of the
10 phrase "in the last twelve months." Unless the customer
11 can substantiate changed circumstances as we have
12 described, the Contract Demand for customers with on-site
13 generation should be set based on the highest potential
14 demand on the Company's system ever, not just the past 12
15 months. Deletion of the text "in the last twelve months"
16 clarifies that Contract Demand should reflect the highest
17 recorded demand absent such customer substantiation.

18 Q. How would this change be implemented for new customers that
19 install DG under the Standby tariff?

20 A. For new customers, including those who have received
21 service from the Company under firm service rates for less
22 than 24 months, the Contract Demand shall be the kW service
23 requested in the final load letter that accompanies the

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1 Customer's application for service, reasonably adjusted by
2 the Company's engineering evaluation of the customer's
3 electrical equipment and diversity of load. If the
4 customer does not supply this information in an application
5 for service, the Contract Demand will be reasonably
6 determined through the Company's engineering analyses of
7 the customer's electrical equipment and diversity of load,
8 premises to be served, and information supplied by the
9 Customer at the Company's request. This allows Contract
10 Demand to be set in accordance with the actual maximum
11 potential demand on the Company's facilities required to
12 serve a customer.

13 Q. Let's consider the example of a new Standby customer who
14 installs two 5MW DGs with the assumption that the maximum
15 potential demand is 10 MW. Because the customer is
16 confident in the performance of the generators, the
17 customer doubts that both DGs would fail at once such that
18 the customer would choose a Contract Demand of 5 MW. Would
19 the Company override that decision and impose a Contract
20 Demand of 10 MW?

21 A. Yes, with the following exception. If this new customer can
22 satisfy the Company that the customer can establish by
23 engineering design and installation that the customer would

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1 not draw more than 5MW from Con Edison and that Con
2 Edison's transmission and distribution system would not be
3 harmed in any way should both of the customer's generators
4 become inoperable, the Company would consider approving a 5
5 MW Contract Demand. Review of such proposals must
6 necessarily be on a case-by-case basis.

7 Q. Has the Company had prior experience on its system where
8 multiple DG units of a single customer became inoperable at
9 the same time?

10 A. Yes.

11 Q. How would this change be implemented for existing customers
12 wishing to install distributed generation under the Standby
13 tariff?

14 A. For existing customers moving to the Standby tariff, the
15 Company would use the same criteria to approve or modify
16 Customer-set Contract Demand that the Company currently
17 uses when it determines the Contract Demand.

18 Q. How would existing DG customers who originally set their
19 own Contract Demand be affected if the Company's proposal
20 were approved?

21 A. A Contract Demand originally set by a Customer will be
22 deemed to be the Contract Demand going forward. If the
23 customer's measured peak demand exceeds the Contract

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1 Demand, the Contract Demand will be increased to the new
2 peak. However, there will be no surcharge for any
3 exceedance of such a Contract Demand.

4 Q. Why is this change to Contract Demand determination
5 necessary?

6 A. This change is necessary to prevent the subsidization of
7 infrastructure that is needed specifically to meet the
8 energy needs of distributed-generation customers on Standby
9 rates by non-DG customers. In its order in Case 11-E-0299,
10 issued on October 18, 2012, the Commission approved the
11 Company's new Standby rate for a single customers with
12 campus setting or multiple buildings and approved the
13 Company's right to review and modify a customer-set
14 Contract Demand. The Commission expressly stated that the
15 "Company's contract demand proposal will also capture the
16 costs associated with the use of local facilities from the
17 actual customer that uses them and avoids the shifting of
18 the associated costs to other customers" (page 14).

19 **XX. Contribution in Aid of Construction**

20 Q. Does the Company require certain new customers for whom the
21 Company will be required to incur high construction costs

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1 to make a payment for the Company's incremental cost of
2 providing electric facilities?

3 A. Yes, pursuant to the Commission's February 17, 2010 Order
4 in Case 08-E-0539, the Company filed tariff amendments
5 effective March 1, 2010, to establish this requirement.
6 The tariff amendments provide that if the Company estimates
7 that total construction costs directly attributable to
8 supplying a new or expanded service to a new or existing
9 customer will exceed \$2 million, the customer is obligated
10 to make a non-refundable payment for the Company's
11 incremental cost, referred to as a contribution in aid of
12 construction ("CIAC"). The customer cost contribution is
13 equal to the Company's estimated total construction cost
14 less the Customer's cost responsibility under the
15 Commission's line extension rules and less the product of
16 five times the customer's estimated annual pure base
17 revenue, if such difference is greater than zero.

18 Q. Since March 1, 2010, has the Company required any customers
19 to pay a CIAC?

20 A. No. Since the CIAC tariff provisions became effective,
21 there were only two new cases where total construction
22 costs were expected to exceed \$2.0 million. In each case,
23 five years of pure base revenue was greater than the

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1 company's total construction cost and, therefore, no CIAC
2 was required. All pending cases where customers had been
3 given a specific service determination prior to March 1,
4 2010, the effective date of the Commission's order, were
5 excluded from consideration. In addition, the cost of
6 transformer unit(s) was not included as part of the
7 Company's total construction costs. As we discuss later in
8 our testimony, the \$2 million target level did not reflect
9 this cost. Lastly, in accordance with the February 17,
10 2010 Order noted above, the Company contemporaneously made
11 additional changes to its tariff that reduce the expected
12 costs for larger new projects. The standard voltage for
13 electric service was changed to allow Con Edison to
14 designate three phase, four wire, 265/460 volt service
15 and/or high tension service when it is least cost to the
16 Company. In these cases, the customer is responsible for
17 construction of more of the facilities necessary for
18 electric service than when service is provided at a lower
19 voltage. In the case of High Tension service, the
20 Company's construction cost can be lower than supplying
21 standard service. The Company's ability to designate
22 either service has reduced the number of new or expanded

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1 service projects requiring Company construction costs in
2 excess of \$2 million.

3 Q. Does the Company propose any changes to the CIAC provisions
4 in its electric tariff?

5 A. Yes, the Company proposes two changes. The Company
6 proposes to amend the tariff: 1)to provide that the cost of
7 the physical transformer(s) is not included in the total
8 construction costs and 2) to provide that the CIAC charge
9 be the lesser of (a) the total construction costs less \$2.0
10 million or (b) the total construction costs less the
11 Customer's cost responsibility under General Rule 5.4.3 or
12 5.5.3 and less the product of five times the estimated
13 annual Pure Base Revenue that would be obtained from the
14 Customer under the rates of the appropriate Service
15 Classification, if such difference is greater than zero.

16 Q. Please explain the reason for these proposed changes to the
17 electric tariff regarding the cost of the transformer(s).

18 A. When the Company initially filed a tariff provision to
19 charge customers CIAC, the Company proposed a \$5 million
20 construction cost threshold that reflected, in part, the
21 cost of a transformer. Upon DPS Staff's review of the
22 construction costs associated with a variety of specific
23 projects, Staff proposed and the Commission approved a

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1 threshold of \$2 million. The Company had provided Staff
2 with project information about job costs for multiple
3 projects for about 4 years. The construction costs of the
4 projects reviewed by Staff included the transformer vault,
5 the transformer connections to the primary and secondary
6 cables, and the cost to deliver and hoist in the
7 transformer. Inadvertently, the costs did not include the
8 cost of the transformer itself. Transformer equipment is
9 budgeted separately from the main equipment budget, and the
10 project log used to provide 4 years of project cost data
11 was not amended to include the transformer budget data.
12 Because the transformer cost was not considered in
13 establishing the \$2 million threshold, we propose to
14 exclude the cost of the transformers from the calculation
15 of the total cost of construction.

16 Q. Please explain the reason for the proposed change to
17 the electric tariff regarding the calculation of the
18 CIAC charge.

19 A. The tariff currently states that the customer pays the
20 entire amount by which total construction costs
21 exceeds the Customer's cost responsibility under the
22 line extension rules (line extension responsibility)
23 and the product of five times the customer's estimated

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1 annual pure base revenue (PBR contribution). We
2 propose that when the customer's line extension
3 responsibility and PBR contribution do not exceed the
4 total construction cost, the customer be charged the
5 lesser of the amount by which total construction costs
6 exceeds \$2 million or the total of the customer's line
7 extension responsibility plus PBR contribution.

8 Q. Please provide an example of how the Company's two
9 proposals would work.

10 A. The following example shows how the Company's two
11 proposed changes would work. A large new residential
12 building is determined to require a total construction
13 cost of \$2.7 million, excluding the transformer costs,
14 and the PBR contribution is expected to be \$1.7
15 million with no line extension responsibility.
16 Because the total construction cost exceeds the \$2.0
17 million threshold, the customer must pay a CIAC
18 charge. The customer's CIAC charge is \$700,000, which
19 is the lesser of the difference between the total
20 construction cost and \$2.0 million, and the difference
21 between the total construction cost and the customer
22 PBR. If the customer PBR were \$2.2 million, the
23 customer would pay a CIAC charge of \$500,000, the

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1 amount by which the total construction cost exceeds
2 the customer's PBR, because it is less than the
3 difference between the total construction costs and \$2
4 million.

5 Q. Please compare the results in the example you just
6 gave with the results under the current tariff.

7 A. Under the current tariff, the Company's total
8 construction charge is \$2.7 million (transformer cost
9 is not included in total construction cost), and the
10 threshold is \$2 million. Because the total
11 construction cost exceeds the threshold, the customer
12 must pay a CIAC charge. The customer's CIAC charge is
13 \$1 million, which is the amount by which the total
14 construction cost (\$2.7 million) exceeds the
15 customer's PBR (\$1.7 million). If the customer's PBR
16 were \$2.2 million, the result under the current and
17 proposed tariffs would be the same: the customer would
18 pay a CIAC charge of \$500,000 which is the total
19 construction cost (\$2.7 million) minus the customer
20 PBR (\$2.2 million).

21 Q. Please explain the reason for this proposal.

22 A. We are particularly concerned with the construction of
23 new residential buildings receiving subsidies for low

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1 income or middle income housing in low income
2 neighborhoods. Such developers, already working on
3 small margins, could be dissuaded by a substantial
4 CIAC cost. Assume for example a construction cost to
5 the company of \$2.1 million, without transformer cost,
6 and five-year pure base revenue of \$1,000,000 for
7 "Residential Project 1." The CIAC charge would be
8 \$1.1 million [\$2.1 - \$.1 million]. This charge could
9 be a very significant cost to a residential developer
10 particularly in a low income neighborhood. Under the
11 Company's proposals (assume \$2.5 million construction
12 costs excluding the cost of transformers), the cost of
13 construction exceeds the \$2.0 million threshold and
14 CAIC is applicable. The CIAC charge would be \$500,000
15 (\$2.5 million construction costs minus \$2 million).
16 Based on revenue expectations, we expect residential
17 projects to become the primary cases where CIAC costs
18 are charged over the next several years. This is
19 expected based on the load factor and lower service
20 rates between residential and commercial customers.
21 Most residential sites request and require 120/208V
22 service, which typically incurs a higher total
23 construction cost to the Company versus 460V or High

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1 Tension service. Most residential construction
2 projects involve the construction of vaults in the
3 sidewalk adjacent to the residential building, versus
4 commercial construction projects where the customer is
5 often required to install facilities within their
6 premises at its cost. In addition, residential
7 buildings generally have lower pure base revenues than
8 commercial projects and, therefore, are more likely to
9 incur CIAC costs.

10 Another reason for our proposal is to mitigate cases
11 where a customer experiences disproportionate costs
12 compared to similar projects. In comparison with the
13 example of Residential Project 1 with a \$2.1 million
14 construction cost to the Company, which we just
15 discussed, "Residential Project 2" with a construction
16 cost of \$1.9 million will not exceed the \$2 million
17 target level, the project will not require a revenue
18 test, and the customer will not be charged a CIAC
19 cost. There is the potential for customer
20 dissatisfaction and complaints where one customer pays
21 a substantial CIAC charge and another customer with a
22 similar project is not charged at all. Under the
23 Company's proposals, the Residential Project 2 would

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1 still not pay a CIAC charge because the \$1.9 million
2 construction cost does not exceed the \$2.0 million
3 threshold, while the CAIC for Residential Project 1 is
4 reduced from \$1.1 million to \$500,000.

5 Q. Is the Company considering any circumstances under which it
6 would grant a waiver of some or all of a CIAC that might
7 otherwise be applicable?

8 A. Yes. The Company is considering a waiver for any applicant
9 that can demonstrate a measurable and verifiable energy
10 efficiency commitment by meeting or exceeding the energy
11 reduction goals set forth below, with separate goals
12 established for new construction and for existing building
13 renovation. For new construction, a customer must
14 demonstrate (with independent third party verification)
15 that the customer's new construction will have an HVAC
16 system that uses 34% less energy than ASHRAE 90.1-2007
17 standards. For an existing building renovation the
18 customer must demonstrate (with independent third party
19 verification) that the HVAC system will use 30% less energy
20 than ASHRAE 90.1-2007 standards. In each case, the
21 customer must also show that new lighting systems use 30%
22 less energy than the requirements of the New York State
23 Energy Conservation Code and that new building HVAC and

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1 lighting systems are controlled by an automated building
2 management system (or by an optimized combination of
3 systems). Finally, commissioning, measurement and, as
4 noted above, independent verification will be required. To
5 the extent that the Commission approves the Company's
6 waiver proposal in this proceeding, the Company would file
7 with the Commission a program and tariff leaves
8 implementing such proposal within 90 days of the issuance
9 of the approval order.

10 Q. What is the basis for the particular energy use reductions
11 in your proposal?

12 A. Using ASHRAE standards as a recognized baseline, the
13 specific percentage reductions were selected to be
14 consistent with the LEED Platinum certification energy
15 requirements.

16 Q. Why does your proposal focus on HVAC and lighting?

17 A. The Company's proposal focuses on HVAC and lighting because
18 they constitute a large percentage of energy use with
19 significant potential for cost-effective energy savings.
20 Simply put, HVAC and lighting offer the biggest bang for
21 the buck.

22 Q. Why does your proposal require controls?

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1 A. Controls provide a means to optimize building HVAC and
2 lighting systems. An HVAC system without an automation
3 system will not be able to achieve the energy savings
4 required by the proposal.

5 **XXI. Charges for Special Services**

6
7 Q. Please discuss the Company's proposal to update charges for
8 special services performed by the Company

9 A. The Company is proposing to update charges for special
10 services performed by the Company as follows:

- 11 • High potential proof test, per visit to the premises:
 - 12 o Up to four hours: \$1,818.00
 - 13 o For each additional hour or portion thereof: \$455.00
- 14 • Megger Test - 2 people 1 hour: \$455.00
- 15 • Dielectric Fluid Test
 - 16 o First sample: \$1,270.00
 - 17 o Each Additional sample taken at the same time: \$917.00
 - 18 o Each sample taken by the Customer: \$816.00

19 Q. What is the basis for the proposed charges?

20 A. These charges were last updated effective April 1, 2008.
21 The proposed charges reflect the Company's 2012 cost for
22 labor, vehicles, corporate overhead, and chemical lab, and

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1 gross receipts taxes.

1

2 **XXII. Notices of Violations**

3

4 Q. What is the next subject of your testimony?

5 A. We will discuss the Company's effort to reduce costs for
6 Notices of Violation ("NOVs") and traffic violations.

7 Q. Please define an NOV.

8 A. NOVs are Notices of Violation issued by the New York City
9 DOT or the New York City Police Department's Traffic
10 Special Operations ("TSO") for alleged failures to comply
11 with the DOT's Highway Rules or New York City's
12 Administrative Law Code.

13 Q. Can you offer an overview of the situation the Company
14 faces with regard to NOVs?

15 A. Yes. As part of the Company's overall commitment to safely
16 providing reliable utility service to its customers, the
17 Company's commitment to reduce costs remains strong. The
18 Company has demonstrated this commitment to reduce the
19 number of NOVs and has seen success in this effort, a
20 success we expect to continue. Through some very specific
21 programs that we have implemented over the past few years,
22 we have significantly reduced NOVs in specific categories

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1 and will continue to drive this effort. However, no matter
2 how aggressively we work to reduce NOVs and no matter how
3 cooperatively we work with the City, there will always be a
4 degree of tension between the City's goal to maintain the
5 flow of traffic (motor vehicles, pedestrians, and bike
6 riders) on its streets and the Company's obligation to
7 provide safe and adequate utility service to its customers
8 because the Company's obligation requires regular work on
9 those same City streets. The best illustration of this
10 challenge is the fact that as the Company and the DOT
11 completed development of specialized permits to reduce NOVs
12 for a particular type of violation, the DOT increased
13 penalty costs in that same NOV category and also introduced
14 new administrative compliance requirements in other areas
15 that are challenging. In other words, while the Company is
16 working hard to reduce NOVs and traffic tickets, a certain
17 level of cost is an inevitable consequence for a utility
18 that constructs and maintains facilities in the streets of
19 New York City.

20 Q. Returning to the NOV costs, can you describe the Company's
21 efforts to address this issue?

22 A. Yes. In June 2009, the Company formed the Government
23 Liaison Department within the Construction organization and

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1 encompassed the Permits and the Compliance groups to manage
2 the Company's relationship with the DOT and improve the
3 Company's performance related to NOVs. Among other
4 activities discussed below, this department coordinates
5 meetings between local DOT borough managers/coordinators
6 and the Company. These meetings have proven successful in
7 improving relationships and addressing some of the issues
8 the DOT has identified with Con Edison's street work.

9 Q. Can you identify and comment on the leading categories of
10 NOVs?

11 A. Yes. In the twelve months ending June 30, 2012, the
12 Historic Year, the six leading categories of NOVs were (1)
13 permit stipulation violations; (2) failure to obtain
14 confirmation number for administrative closure of permit to
15 work on a protected street; (3) emergency/authorization
16 (embargo) permit violations; (4) failure to restore
17 excavation in required time; (5) hardware not flush with
18 surrounding roadway; and (6) use/opening and closing of
19 roadway/sidewalk. It should be noted that Categories 2 and
20 4 appeared as NOV drivers for the first time during this
21 period. Category 2, failure to obtain confirmation number
22 of administrative closure of permit to work on a protected
23 street is driven by the City's new administrative

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1 requirement that a permittee obtain a confirmation number
2 substantiating DOT's administrative closure of the permit.
3 Violations in Category 4, failure to restore excavation in
4 required time, are driven by the City's reduction in the
5 time within which surface restoration must be completed.
6 Moreover, in late 2011, the DOT doubled its fee schedule
7 for embargo-related NOVs from \$1,000 per violation to
8 \$2,000 per violation. These violations are related to
9 Category 3. Thus, the Company's cost-reduction efforts
10 with respect to those violations were essentially negated
11 when the DOT doubled the cost of these violations.

12 Q. Please describe the nature of each of these NOV categories
13 and the Company's efforts to reduce them.

14 A. The first category is Stipulation Violations. The DOT
15 issues permits that contain conditions known as
16 "stipulations" authorizing the Company to work in the City
17 streets. The Government Liaison Department has coordinated
18 and liaised with the DOT to provide specialized
19 stipulations to match types of field work the Company's
20 operating groups (Electric, Gas, Steam, and Construction)
21 must perform. Stipulations tailored to specific jobs
22 reduce NOVs that might have resulted from more general
23 stipulations. For example, permits for work on roadways

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1 generally contain the stipulation that the full width of
2 the roadway be open to traffic when the work site is
3 unattended. There is now a clarifying stipulation that
4 allows barricades to remain on an unattended roadway for
5 the curing of concrete that is used to keep our structures
6 at grade level in the street.

7 Q. What else is the Company doing to address Stipulation
8 Violations?

9 A. The Government Liaison Department remains in discussion
10 with the DOT to develop additional specialized stipulations
11 to facilitate street work in Manhattan and the other
12 boroughs, especially for gas and steam work.

13 Q. Can you give an example?

14 A. Yes. For example, permits generally contain the
15 stipulation that when a site is unattended, the roadway
16 must be restored to its full width. The Company is seeking
17 a clarifying stipulation that would permit a properly
18 barricaded excavation to remain open to address the venting
19 of a gas or steam leak.

20 Q. Are there other actions for Stipulation Violations?

21 A. Yes. The Government Liaison Department worked with the
22 operating groups to develop a short list of the most common
23 jobs in field construction and a corresponding stipulation

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1 template for consideration by the DOT. While the DOT has
2 not adopted all of the Department's suggestions, these
3 discussions gave the DOT a better understanding of why the
4 Company needs a modification of a stipulation to properly
5 handle a particular type of job. These efforts should lead
6 to further practical application of the rules that allow
7 specific types of work to be conducted without violations.
8 In addition, internally, the Department conducts ongoing
9 training sessions with the Company's operating groups and
10 contractors on the importance of closely reading the
11 detailed stipulations of permits. The Department created
12 pre-construction, field construction, and post-construction
13 check lists to help operating groups and their crews comply
14 with the stipulations of their permits.

15 Q. Please describe "failure to obtain confirmation number for
16 administrative closure of permit to work on a protected
17 area" and describe the Company's efforts to reduce this
18 violation.

19 A. In order to undertake work on a protected street, the DOT
20 requires a permit.

21 Q. What is a "protected street"?

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1 A. A protected street is any street that was completely
2 repaved within the last five years prior to the date of the
3 permit application.

4 Q. Please continue.

5 A. In November 2011, the DOT established a new requirement,
6 purely administrative in nature, to support its own
7 administrative closure of permits to work on a protected
8 street. Prior to then, the only action required of a
9 permittee at the end of a protected-street project was
10 advance notice to the DOT if the back fill of an excavation
11 was required. No other activities on a protected street,
12 such as work on a sidewalk, required any formal action at
13 the end of the project. The change in the rule now makes
14 it mandatory for the permittee to request a confirmation
15 number from the DOT to administratively close all protected
16 street permits instead of the prior, simple notification
17 that applied only for backfill work.

18 Q. Can you give an example?

19 A. Yes. If the Company takes out a permit and then takes no
20 action under the permit, the City requires the Company to
21 obtain a confirmation number to close that inactive permit
22 or the Company will receive an NOV. An inactive permit can
23 occur, for example, if field conditions change so as to

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1 prevent work from proceeding, or if priorities change a
2 contractor's assignment, or in the case of work for a
3 particular customer, the customer is not ready for the
4 Company to do the job.

5 Q. Please continue.

6 A. These NOVs address a new administrative requirement and do
7 not address any safety or traffic issues, a failure to
8 obtain a permit, or a violation of permit stipulations.

9 Q. What is the Company doing to address this violation?

10 A. In an effort to reduce this type of NOV, the Department
11 created an electronic tutorial for the Company's operating
12 groups on how to request a confirmation number using the
13 DOT's website. Email notifications and reminders of this
14 regulatory change were sent to the operating groups, and
15 presentations were made at various staff meetings to remind
16 the operating groups of the importance of requesting
17 confirmation numbers to close permits for work on protected
18 streets.

19 Q. Is the Company doing anything else with respect to this
20 NOV?

21 A. Yes. In addition, the Department is working to implement
22 system changes in its Construction Permit Tracking System
23 ("CPTS") by providing automatic alerts that will serve as a

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1 reminder to the Company's operating groups when permits are
2 within five days of expiration. The alert will remind work
3 crews to extend their permits, request a new one, or, if
4 the job is completed, police the location to remove all
5 material, equipment, and debris, thereby eliminating these
6 types of NOVS. For expiration of protected streets
7 permits, the alert will also remind the work crew to obtain
8 a confirmation number of permit closure. Company
9 contractors have also been put on notice that failure to
10 comply with the confirmation number requirement will result
11 in back charges to the contractors. I would also note that
12 the Department maintains an on-line training course for use
13 of the CPTS on the Company's intranet website.

14 Q. Please explain the next type of violation and the Company's
15 efforts.

16 A. The next is emergency/authorization (embargo) permit
17 violations. The DOT issues an embargo number to authorize
18 the Company to perform emergency work on a critical roadway
19 during the restricted period typically between 7am and 8pm,
20 Monday through Friday.

21 Q. What is a critical roadway?

22 A. Critical roadways are "highly trafficked" streets in the
23 City. If there is any activity on these roadways with

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1 respect to work related structures like vaults, manholes,
2 and service boxes, this activity should take place between
3 the hours of 7 am and 8 pm only if there is an emergency
4 for which an embargo permit number for the DOT is
5 necessary. For reference, most of the streets in Manhattan
6 are critical roadways.

7 Q. Please continue.

8 A. NOVs typically result from the difference in interpretation
9 between the Company and the DOT as to what constitutes
10 emergency work on critical roadways. The Company considers
11 work necessary for safety to the public and its employees,
12 service continuity, and/or prevention of equipment damage
13 to be an emergency. DOT field inspectors who issue
14 violations consider only the actual loss of service to
15 customers, not the imminent loss of service, to be an
16 emergency. Thus, even if the Company has an embargo
17 number, an NOV can be issued for opening a structure
18 (vault, manhole, or service bus) on a critical roadway
19 during restricted hours if the DOT subsequently deems the
20 work to be non-emergency.

21 Q. What is the Company doing to address this type of
22 violation?

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1 A. To address the Company's ability to perform necessary work
2 on critical roadways without incurring this type of NOV,
3 the Department began meeting with the DOT in 2010. This
4 led to the development of the Emergency Access Cover
5 Opening ("EACO") program. Beginning as a pilot program in
6 lower Manhattan, the program was expanded to provide
7 planned permits in lieu of ordering embargo permits for
8 work in structures located in the parking lanes of critical
9 roadways during restricted hours throughout Manhattan.
10 Subsequent Department efforts to explain to the DOT the
11 necessity of performing various types of work on critical
12 roadways during restricted hours to maintain the electric
13 infrastructure at peak efficiency have led to the
14 development of another pilot program to provide "High
15 Priority" permits in lieu of requesting embargo numbers.
16 These permits authorize crews to access structures located
17 anywhere on critical roadways (including drive lanes and
18 intersections) during restricted hours for the life of the
19 permit (as compared with the EACO permits, which authorize
20 access only to structures in the parking lane). In
21 September of this year, representatives from Government
22 Liaison and Manhattan Electric Operations met with the
23 DOT's Assistant Commissioner and his Emergency

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1 Authorization Unit ("EAU") to begin negotiations on another
2 pilot program aimed at further reducing violations for
3 performing non-emergency work on a critical roadway during
4 restricted hours with an embargo number. This pilot
5 program is driven by work the Company has to perform
6 related to processing and restoring to service electric
7 feeders that have automatically been taken off-line to
8 protect the integrity of the electric system. This program
9 will require specific wording for the request of emergency
10 embargo numbers. The specific wording, "Primary Feeder -
11 Open Auto," would alert the DOT that the project is the
12 type that both Con Edison and the DOT would agree is a real
13 emergency. This pilot program should also help to reduce
14 the number of NOV's. With both EACO and High Priority
15 permits in place, the Company has seen a recent significant
16 decrease in Category 3. It is anticipated that the new
17 pilot program related to open auto electric feeders will
18 result in further NOV reductions in this category.

19 Q. Is there anything you wish to add in connection with this
20 violation?

21 A. Yes. Despite the efforts by both the Company (and the
22 City) described above, as noted above in November 2011, the
23 City amended its rules to double the fine for embargo-

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1 related NOVs from \$1,000 to \$2,000 per violation. Thus,
2 although the net effect was the number of embargo-related
3 NOVs was reduced, the reduction in the amount paid in fines
4 was not as significant as it would have been had not the
5 fine been doubled.

6 Q. Please discuss the next violation.

7 A. The next violation is "failure to permanently restore
8 excavation within the required time." The increase in this
9 NOV in the Historic Year was due to a change in the DOT's
10 rules and regulations that took effect in November 2011.
11 Before that change, permittees had ten working days from
12 the expiration of a permit to permanently restore an
13 excavation. The changed rule now requires all street
14 excavations to be permanently restored within the term of
15 the permit. In other words, work crews lost ten days or
16 more (considering weekends and holidays) to complete a job
17 and avoid an NOV. The Department's enhancements to the
18 CPTS system described above to alert the operating groups
19 that their permits will expire within five days should help
20 reduce the number of violations in this category.

21 Q. What is the next category?

22 A. The category "hardware not flush with surrounding area"
23 includes a variety of conditions relating to Company

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1 equipment and structures that can be out of compliance with
2 the DOT's rules. Prior to issuing NOVs, the DOT often
3 issues Corrective Action Requests ("CARs") to alert the
4 Company of various street defects in need of remediation
5 and allows 30 days for correction to avoid an NOV.

6 Examples are hardware-related issues (these include utility
7 cover/street hardware not flush with the roadway, loose and
8 noisy covers, defective covers/grating, and street
9 conditions extending 12 inches from the structure),
10 resealing cuts in the roadway, laying down lane markings,
11 and general housekeeping of the job sites (such as removing
12 barricades, debris, and equipment). The Company has taken
13 steps to more effectively address CARs in a timely manner
14 both to correct the problem for Company structures and job
15 sites and to avoid issuance of follow-up NOVs.

16 Q. Please continue.

17 A. This effort began in January 2009 when the Company
18 centralized the management of hardware-related CARs. The
19 Special Projects Group ("SPG") was created to manage and
20 administer the Company's response for all CARs, from prompt
21 examination of the conditions in the field, to allocation
22 of the work to operating sections in the Construction,
23 Electric, Gas, or Steam organization, to tracking of

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1 progress and closeout. The SPG handles all hardware-
2 related issues and allocates other work to the operating
3 sections. All CARs, and NOVs, are stored in the Company's
4 Summons System, a repository that can process and track
5 them from receipt to close out after the condition has been
6 corrected. The Company has improved its response time for
7 fielding CARs (assessing the condition in the field and
8 assigning work responsibility) to within five days of
9 receipt.

10 Q. What other steps has the Company taken?

11 A. In 2009, the DOT created a new violation code for failure
12 to install color code markers indentifying the Company's
13 street excavations. This requirement was not previously
14 enforced but in 2010, the DOT issued 116 of this violation
15 type to the Company. By 2011, the number rose to 508. In
16 response to this new violation, a retrofit program was
17 established to specifically address this condition. As a
18 result, the Company purchased special drill bits and color
19 code markers to complete the installation of color code
20 markets at a large number of excavation sites in compliance
21 with the DOT's requests.

22 Q. Please continue.

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1 A. Certain CARs require DOT to issue a permit before the
2 Company can correct the condition. Examples are re-grades
3 (repair) of street hardware, such as manholes, service
4 boxes, and vaults, that are not flush with the roadway (too
5 high or too low), or are loose and noisy, or have broken
6 concrete and/or asphalt around the perimeter of the
7 structure. Delays in obtaining a permit can delay work
8 beyond the CAR's 30-day correction period and trigger an
9 NOV. The Government Liaison Department helps to expedite
10 the request and issuance of street permits to facilitate
11 timely correction of the condition. These efforts not only
12 maintain the quality and integrity of the Company's
13 structures and the City's roadways, but also reduce NOV's.

14 Q. Please address the final leading category of NOV.

15 A. NOV's can result when work continues beyond the expiration
16 date of a permit or when material, equipment, or debris
17 remain on-site thereby impeding a parking lane or sidewalk.
18 As discussed above, the Department is working to implement
19 system changes in its CPTS system to automatically alert
20 the operating areas when permits are within five days of
21 expiration so that prompt corrective action can be taken to
22 avert this type of NOV.

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1 Q. Has the Company taken other steps not related to specific
2 types of NOVs to generally reduce this cost?

3 A. Yes. The Company had been working on real-time service of
4 NOVs, improved external communication, and improved NOV
5 reporting.

6 Q. Describe what you mean by real-time service of NOVs and how
7 this reduces the Company's costs.

8 A. The Government Liaison department, working in conjunction
9 with other Company personnel and the DOT, implemented a
10 process change to increase employee and contractor
11 accountability for NOVs. Beginning in January 2012, after
12 long negotiations, the DOT began sending us near real-time
13 email notifications of NOVs issued for embargo violations.
14 In addition to these daily email notifications, beginning
15 in May 2012, the DOT began serving paper (yellow) copies of
16 NOVs directly on Con Edison's field crews in Manhattan to
17 further increase accountability for NOV infractions.

18 Q. How does this help reduce costs?

19 A. Similar to prompt receipt of a parking ticket, it is
20 anticipated that receipt of the NOV in real-time will help
21 employees and contractors improve their work habits to
22 reduce NOVs because they would know in real time that there
23 is a non-compliance issue. Currently, there is a three-to-

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four week lag between the time a NOV is issued and the time it is delivered to the company. This time lag is at times even greater for NOVs issued by the NYPD TSO. However, based on our discussions with the DOT, the next step in reducing this time lag is planned for late 2012 when we anticipate that the DOT will begin electronic transfers of all NOVs to the Company's Summons System software upon issue of the NOVs. This real-time electronic distribution is planned to include all NOV types in every borough of the City.

Real-time service of NOVs is expected to help operating groups in the following ways: (1) assess the reason(s) for the issuance of an NOV to avoid repetition; (2) assess a contractor's responsibility for the NOV and collection of a back charge; (3) permit immediate collection of the documentation to challenge the NOV if appropriate; and (4) allow the field crew to take immediate corrective action and to request an embargo number to reduce repeat NOVs arising out of the same situation. Real-time service of NOVs will also help the operating groups make a better decision on the type of permit (embargo, EACO, or high priority) appropriate for work in structures on critical roadways and to quickly correct administrative errors. If,

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1 for example, an NOV was issued because the permit
2 incorrectly listed a street segment rather than an
3 intersection, that detail could be readily corrected.

4 Q. Please discuss "external communication."

5 A. In addition to the Department's regular communication with
6 the DOT described in this testimony, the Department also
7 meets with the leadership of the NYPD's TSO to secure
8 faster processing of its NOV's. The goal is to decrease the
9 lag time from several months to two weeks or less for the
10 service of TSO - issued NOV's on the Company. The TSO and
11 the DOT could issue an NOV each day for the same violation
12 before the Company would even be aware of the first
13 violation. Reduced lag time will allow the Company to
14 correct the condition more quickly and reduce the number of
15 repeat NOV's issued for the same condition.

16 Q. Can you give an example?

17 A. Yes. Prompt receipt of an NOV for failure to remove safety
18 barricades after work is finished will allow the Company to
19 address the issue and reduce additional NOV costs.

20 Q. What else does the Company do with respect to external
21 communication?

22 A. The Department also monitors proposed changes to the DOT's
23 rules and regulations and files comments where appropriate

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1 to oppose or explain the impact of changes. The Department
2 also regularly discusses issue of common concern with
3 National Grid and Verizon/Empire City Subway to benchmark
4 mitigation strategies and to present a coordinated
5 presentation during meetings with the City. On occasion,
6 the Department works with those companies to file joint
7 statements on proposed regulatory changes.

8 Q. Please address "improve NOV reporting."

9 A. Beginning in May 2012, the Department began piloting the
10 use of a software program that provides a new, more user-
11 friendly method of tracking and reporting NOVs. This
12 system provides a transition from reactive monthly NOV
13 reporting to a proactive NOV dashboard. With the ease and
14 immediacy of a dashboard reporting format, operating groups
15 throughout the Company will be able to collect and analyze
16 data highlighting specific areas of concern to facilitate
17 development of solutions to problems.

18 To improve the performance of groups within the Company
19 that incur NOVs, the Department has taken the following
20 additional measures to reduce NOV costs: it conducts
21 awareness training, holds periodic meetings to review NOV
22 performance and to implement/enhance NOV mitigation
23 measures, and makes presentations at Business and Safety

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1 and Contractor meetings on the leading drivers of NOVs and
2 methods to avoid them.

3 Q. Please turn your attention to the Company's efforts to
4 reduce traffic violations and explain what steps are being
5 taken.

6 A. The Company track violations issued to Company vehicles in
7 the course of business operations. The bulk of vehicular
8 violations are red-light camera violations ("RLCVs") and
9 parking tickets. The Company uses various measures to
10 reduce the incidence and costs of these violations.

11 Q. Please comment on RLCVs.

12 A. The Company treats RLCVs as a serious public safety concern
13 and addresses this concern both by education of its
14 workforce and by imposing financial consequences on
15 offending drivers. The Company receives from the City
16 copies of any RLCVs issued against its vehicles. While the
17 Company makes the initial payment immediately, the various
18 operating groups are required to identify the driver and
19 obtain reimbursement to the Company for the fine. The
20 Company uses the Company's Safety and Health Information
21 Management System ("SHIMS") tracking system to generate
22 organization-specific reports to provide the total number

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1 of RLCVs along with the associated vehicle and driver
2 information, as well as reimbursement status.

3 Q. How else does the Company seek to manage RLCVs?

4 A. The Company continued to exploit opportunities to
5 communicate how red-light camera violations negatively
6 impact the Company's safety culture. The morning job
7 briefing continues to be one of the best opportunities to
8 discuss the hazards associated with running red lights and
9 the importance of avoiding RLCVs. A feature on RLCVs was
10 presented in a video news magazine that is viewed at
11 monthly safety meetings across the Company and is available
12 to all employees on the Company's Environment, Health and
13 Safety intranet site as well as on DVD.

14 Individual Company organization actively address the issue
15 of RLCVs in a variety of ways including presentation on
16 driver behaviors, weekly reporting and monthly driver
17 performance profiles, notification to driver's supervisor
18 for follow-up discussion and safety counseling, and review
19 of overall driving records to identify need for driver
20 safety training.

21 Q. Please discuss parking violations.

22 A. With regard to parking violations, like RLCVs, the
23 Company's policy is to establish responsibility and

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1 reimbursement. For example, the Company's policy on
2 parking violations appears in Corporate Instruction CI 720-
3 2 "Parking Violations." Operations managers are expected
4 to review every parking ticket to determine the extent to
5 which it is unavoidable in the course of business. In
6 situations of unavoidability, such as the need to park a
7 vehicle with attendant equipment close to a necessary
8 repair, an affidavit describing why the ticket was
9 unavoidable is prepared to support dismissal or reduction of
10 the fine. If a ticket was not the direct result of
11 necessary business operations, employees are required to
12 reimburse the Company or the fine.

13 Q. Please continue.

14 A. To help manage these violations, the Company is enrolled in
15 the City's "fleet" program, which provides additional
16 reporting capabilities so that the Company is aware of
17 parking violations issued to its vehicles. Enrollment in
18 this program also allows additional time for the Company to
19 respond before penalties accrue on fines, affording the
20 Company the ability to timely dispute the tickets. The
21 Company has found it cost-effective to manage parking
22 violations through a third-party contractor. The

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1 contractor reviews the "fleet" reports from the City for
2 possible dismissals and/or reductions in fines.

3 Q. Can you summarize the Company's efforts to reduce these
4 costs?

5 A. Con Edison is committed to reducing NOVs to the extent
6 feasible while at the same time fulfilling its obligation
7 to provide safe and adequate electric, gas, and steam
8 service. The Company's Government Liaison Department
9 continues to work collaboratively with the City's agencies
10 to develop practical infrastructure work solutions that
11 address the concerns and needs of both the Company and the
12 City. The Department is establishing and promoting
13 effective policies, procedures, and systems at Con Edison
14 to more effectively manage infrastructure work on the
15 City's streets to reduce NOVs. Con Edison's operating
16 organizations are working to reduce traffic violation costs
17 through education of personnel, tracking infractions and
18 causes, allocating reimbursement responsibility, and
19 contesting summonses when appropriate. The level of NOV
20 costs that are the net result of these vigorous efforts
21 constitute a reasonable and unavoidable cost of providing
22 utility service.

23 Q. Does this conclude your direct testimony?

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- 1 A. Yes. It does.