

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE
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1 Q. What are the names of the members of the Infrastructure
2 Investment Panel ("Panel")?

3 A. John F. Miksad, John McAvoy, John Mucci, and Marc
4 Huestis.

5 Q. Has the Panel previously submitted testimony in this
6 proceeding?

7 A. Yes.

8 Q. What is the purpose of the Panel's additional
9 testimony?

10 A. The additional testimony will: (1) update the Panel's
11 prior testimony for capital and O&M spending; and (2)
12 respond to the testimony of several witnesses
13 including: Staff's Infrastructure Investment Panel
14 (SIIP), Nicola Jones (Reliability Incentive Mechanism),
15 and John Sennett (Security); the City of New York and
16 The Metropolitan Transportation Authority witness
17 Harvey Arnett; and the Consumer Protection Board
18 witness Helmuth Schultz, III, relating to our initial
19 testimony in this proceeding.

20 Q. Has the Panel updated its previous Exhibits?

21 A. Yes, Exhibits IIP-1; IIP-2; IIP-4; IIP-5; IIP-6; IIP-7;
22 IIP-8; IIP-9 have been updated.

23 MARK FOR IDENTIFICATION EXHIBIT _ (IIP-1 Revised);

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1 (IIP-2 REVISED); EXHIBIT _ (IIP-4 REVISED); EXHIBIT _
2 (IIP-5 REVISED); EXHIBIT _ (IIP-6 REVISED); EXHIBIT
3 _ (IIP-7 REVISED); EXHIBIT _ (IIP-8 REVISED); EXHIBIT _
4 (IIP-9 REVISED)

5

6 Q. Please continue.

7 A. We have also updated a number of "white papers" that
8 are included in our previous Exhibits. There revised
9 "white papers" are as follows:
10 IIP-2 pages 1 and 8; IIP-4 pages 1 and 2, 35, 81, 84,
11 89, 127, 139, 141, 145, 158, 160, 173, 179, 197, 200;
12 IIP-5 pages 15, 20, 26, 27, 29, 34, 41; IIP-6 new pages
13 10 and 11; IIP-7 pages 39, 56, 61; IIP-8 pages 1 and
14 19.

15

16 Q. Please provide an overview of your testimony with
17 respect to capital and O&M programs.

18 A. A few capital and O&M projects require updates. We
19 will first discuss the reduction of project funding
20 levels planned by the Company; second, we will discuss
21 accounting corrections; third, we will discuss the
22 Company's acceptance of reduced funding levels as
23 recommended by Staff; and fourth, we will discuss our

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1 objections to the reduced funding as recommended by
2 Staff and CPB witness Schultz.

3

4 Q. Is the Company reducing expenditures for any capital or
5 O&M projects / programs included in its May 8, 2009
6 filing?

7 A. Yes. As detailed in our interrogatory responses and as
8 discussed with Staff during our meetings and field
9 visits, we are eliminating the capital funding for the
10 Generation Interconnection capital projects. In
11 addition, we are reducing the level of O&M funding for
12 the Mobile Stray Voltage program.

13

14 Q. Why is the Company withdrawing the capital funding
15 request for the Generation Interconnection projects?

16 A. Subsequent to our filing, the Company pursued
17 negotiations with the developer of the planned Astoria
18 Energy Unit No. 2 plant and the New York Power
19 Authority (NYPA) to resolve the deliverability and
20 equipment issues associated with connecting the plant
21 at the Astoria East 138 kV Substation. The solution
22 provides for the plant be connected to NYPA's Poletti
23 Q35 L/M 345kV feeders. This revised point of

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1 interconnection will ensure full deliverability, defer
2 the need for future transmission upgrades to support
3 the East 13th Street load area, and avoid costly system
4 upgrade facilities that would have been required for
5 fault current mitigation. As a result, the Generation
6 Interconnection work described as "Astoria East -
7 Install Phase Angle Regulator" and "Corona - Install
8 Series Reactor", will no longer be required, resulting
9 in a \$59 million capital reduction over a two-year
10 period (\$35 million and \$24 million in 2010 and 2011,
11 respectively).

12
13 Q. Is there a chance that this project will not move
14 forward as planned; and if so, will it impact the
15 Company's revenue requirement?

16 A. While a change in strategy by involved parties is not
17 anticipated, if it does occur, or the necessary
18 regulatory approvals cannot be obtained, the Company
19 may be required to reinstate the capital funding
20 request to ensure that system fault currents are
21 appropriately limited.

22
23 Q. Please discuss why the Company is reducing the level of

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1 O&M funding for the Mobile Stray Voltage program.

2 A. The initial 2010 funding request for the Mobile Stray
3 Voltage Program was developed using the 2008 contract
4 rates that were in effect at the time of the original
5 filing. Subsequently, that contract expired, and the
6 Company awarded a new contract through the competitive
7 bidding process that has resulted in cost savings. The
8 new contract rates result in a program reduction from
9 \$21 million (RY-1) to \$15.7 million.

10

11 Q Do you have any corrections to the Company's initial
12 filing?

13 A. Yes. At this time, we have three accounting
14 corrections:

15 5 Year OH Inspection and Repairs - \$90,000 was
16 incorrectly included in the filing and was removed as
17 reflected in our July preliminary update and in our
18 interrogatory response DPS-78;
19 Unit Substation Improvements - \$141,000 is reclassified
20 from Company Labor - Electric Ops STO & SSS, to the
21 element of expense Electric Operations as reflected in
22 our preliminary July update and in our interrogatory
23 response DPS-78;

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1 Scheduling District Operator (S&TO) - \$34,000 program
2 change is removed from Accounting Panel Exhibit as
3 discussed in our interrogatory response to CPB-163.

4

5 Q. Do you agree with Staff's proposal (SIIP, pp. 65-80) to
6 reduce T&D capital programs and projects in 2010 and
7 2011 on the basis that the Company should continue
8 reductions that were itemized in the Company's May 26,
9 2009 austerity-related filing in Case 08-E-0539.

10 A. No. Throughout this section of Staff's testimony the
11 SIIP justifies its proposed reductions by quoting from
12 Con Edison's statement in its May 26, 2009 filing that
13 the capital program reductions are "for the most part,
14 associated with multi-year and low priority programs,
15 and are relatively modest on an individual project or
16 program basis." Staff repeatedly states that the
17 Company's 2009 program reductions for individual
18 programs can be extended to 2010 and 2011 because each
19 is a "low priority" program. We want to make clear
20 that, as a general matter, each of these programs is
21 ultimately important to the safety or reliability of
22 electric system infrastructure. These are "low
23 priority" programs only in comparison with other

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1 programs that are even more important for supporting
2 the safety and reliability of the electric system.
3 Thus, while the Company concluded that these programs
4 can be reduced or deferred in the short term without
5 immediate impacts on safety and reliability, they
6 cannot be further reduced or deferred without careful
7 analysis simply because they were characterized as "low
8 priority." In addition, as cautioned by the Company in
9 its May 26, 2009 filing, "unintended service impacts
10 and higher long-term costs" can result from the 2009
11 capital program reductions. For example, Staff's
12 proposal to continue the reduction in planned
13 expenditures for Distribution Control Center upgrades
14 could seriously impede our ability to proactively
15 replace manufacturer-unsupported computing
16 infrastructure and undersized uninterruptable power
17 supplies and preempt failure of the core engineering
18 analysis systems that are operated in the control
19 systems. Such failures would degrade the Company's
20 ability to maintain system reliability and respond to
21 emergency system conditions. That is not to say that
22 no further reductions or deferrals are possible beyond
23 2009. To the contrary, the Company's May 26, 2009

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1 filing committed the Company to seek further austerity
2 reductions, based on careful evaluations, when
3 developing its 2010 budgets. Accordingly, the Company
4 has evaluated Staff proposed "low-priority" reductions
5 and deferrals for 2010 and 2011 and concludes that some
6 of these programs can be further deferred or reduced in
7 scope if necessary in order to make capital available
8 for higher priority work.

9

10 Q. What are the capital programs from the Company's May
11 26, 2009 filing that the Company is agreeing to reduce
12 or further defer based on Staff's recommendations?

13 A. The Company accepts Staff's proposals to reduce or
14 further defer capital funding for the following S&TO
15 programs: Sprain Brook - W 49th St. Feeder M51,
16 Substation's Relay Protection System Redundancy (Single
17 Point of Failure) and the following Electric Operations
18 programs: HiPot, Sectionalizing Switches, Network
19 Reliability, Coastal Storm Risk Mitigation, Targeted
20 DBC Replacement, ATS Installation USS Reliability XW,
21 Vented Service Box Covers, Mapping System Upgrades, and
22 Distribution Engineering Workshop. In addition, the
23 Company concurs with the proposed reduction to the PILC

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1 program with the understanding that the funding
2 reduction in 2010 and 2011, in conjunction with the
3 austerity plan reduction in 2009, will extend the
4 completion date of this multi-year program to remove
5 PILC cable from the primary distribution system by one
6 year from 2020 to 2021. We emphasize that each of
7 these programs is ultimately important to the safety or
8 reliability of electric system infrastructure, and the
9 Company's evaluation was limited to whether these
10 programs can be further deferred or reduced in scope in
11 2010 and 2011 as proposed by Staff if necessary in
12 order to make capital available for higher priority
13 work. We would also note that the Company is
14 continuing its Asset Optimization Strategy to enhance
15 project prioritization tools that support the alignment
16 of the budget to key Company initiatives that include
17 Safety, Reliability, and Customer Excellence. These
18 programs will continue to be evaluated as part of this
19 integrated, long range vision and will be re-evaluated
20 in future years.

21
22 Q. Please discuss Staff's recommendations that their
23 proposed "reductions should continue until the Company

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1 re-evaluates and prioritizes all of its electric
2 capital projects and programs as part of an integrated,
3 long-term vision as described in the recently issued
4 management audit report" (SIIP, p. 77)

5 A. Consistent with the Management Audit findings that the
6 Company needs to establish an integrated long-term
7 vision and plan that both guides electric system
8 expenditures over the longer term and supports
9 effective short term expenditures, the Company is
10 developing a vision and plan for its electric business.
11 Nonetheless, as the Company acts to do so, the Company
12 must maintain the reliability and safety of the
13 electric system in the short term. The Management
14 Audit report states (pages III 21-22), "CECONY aims a
15 number of separate short-to medium-term programs at
16 sustaining the current level of reliability and at
17 reducing risk. Consequently, there do exist many
18 components of effective, long-term infrastructure
19 growth, maintenance, and support, [and] there is not a
20 place where they come together to form a well-
21 coordinated, comprehensive "plan of attack" for meeting
22 the immense economic, financial, operational,
23 reliability, public and employee safety, environmental,

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1 and social challenges that make CECONY a company
2 without U.S. peers in many key respects." Given the
3 need to maintain reliability in both the short and long
4 term, the Company disagrees with Staff's unqualified
5 proposal (SIIP, p. 77) that "the reductions should
6 continue until the Company re-evaluates and prioritizes
7 all of its electric capital projects and programs as
8 part of an integrated, long-term vision as described in
9 the recently issued management audit report." As noted
10 above, we believe that the 2010 and 2011 scope and
11 expenditure of each program should be evaluated
12 individually as to impacts on safety, reliability and
13 costs. .

14
15 Q. Please discuss your disagreement with Staff's
16 recommendation to reduce funding for specific projects
17 and programs listed in Staff's Exhibit _ (SIIP-2).

18 A. First we will discuss System and Transmission
19 Operations, followed by Substation Operations, and then
20 Electric Operations.

21
22 System and Transmission Operations

23 Q. Do you agree with Staff's proposed adjustment to the

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1 S&TO Programs listed in Exhibit SIIP _ (IIP-2)?

2 A. In part. As stated above, we agree with the reduction
3 to the M51 project, but we do not agree with Staff's
4 proposed reductions to: the Emergent Transmission
5 Reliability program, Transmission Feeder Failures
6 program, the EMS Reliability AECC and ECC project; or
7 the Outage Scheduling System project for following
8 reasons:

9 Emergent Transmission Reliability Program (SIIP, pp.
10 24-26) The Company disagrees with Staff's proposed
11 reductions in the Emergent Transmission Reliability
12 program from \$10 million to \$4 million in 2010 and from
13 \$10 million to \$6.2 million 2011. The requested
14 funding should be provided so that we can proactively
15 address operating issues on the transmission system.
16 Several projects have been identified in Exhibit IIP-4,
17 pp. 87-88, and new projects continue to emerge. The
18 installation of increased cooling on 345kV feeders 45
19 and 46 is necessary to meet reliability design
20 criterion for second contingency design for the W49th
21 Street Load Pocket. Presently, the loss of 345kV
22 feeders M51 and M52 could cause Feeders 45 and 46 to
23 exceed their normal ratings. This reliability project

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1 is currently in the engineering phase and purchase
2 orders for equipment have been placed for procurement
3 of long lead material. Construction is projected to
4 start in the fourth quarter of 2009 with an in-service
5 completion in 2010. The 2009 budget for this project
6 is \$3 million and the 2010 budget is \$7 million -
7 substantially higher than the \$4 million proposed by
8 Staff for 2010.

9 Another project that is planned for 2010 and will
10 extend for several years under the Emergent
11 Transmission Reliability Program is the replacement of
12 aging fluid reservoirs and associated equipment for
13 eight selected low pressure fluid-filled feeders at the
14 East River Station. The current reservoir systems are
15 aged and prone to leaks, and direct replacement parts
16 are no longer available. The total cost of this
17 program over four years is about \$5.4 million.

18 Con Edison will be spending more than its \$4 million
19 budget in the Emergent Transmission Reliability Program
20 in 2009. The riser cable section replacement on Feeder
21 69M33 is underway and is expected to be completed in
22 2009 at a cost of \$2.3 million. Feeder 69M33 is
23 constructed with a unique single-phase aluminum sheath

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1 cable design. The feeder is currently in service but
2 continues to experience nitrogen gas leakages due to
3 the difficulty in performing weld repairs on the
4 corrugated aluminum sheath. Between the Feeders 45 and
5 46 project and the Feeder 69M33 project, the Company
6 will spend about \$5.3 million in 2009.

7 Transmission Feeder Failures (SIIP, pp. 27-28) Staff
8 proposes to reduce the funding for Transmission Feeder
9 Failures program in calendar years 2010 and 2011 from
10 \$5 million to \$3.5 million. The Company disagrees.
11 The capital funding forecast of \$5 million per year is
12 based on an average of two manhole-to-manhole cable
13 section replacements at \$2.5 million per incident. The
14 \$2.5 million unit expenditure is based upon actual
15 costs from the last five capitalized cable section
16 failure repair efforts. As a complement to this
17 transmission feeder repair program, the Company has
18 undertaken a proactive program to study 345 kV Feeder
19 M51 to determine the reason(s) for its history of six
20 cable failures since 1999, as described in Exhibit IIP-
21 4, p. 84. In 2008, the Company removed a section of
22 cable along the feeder run, and the removed section was
23 examined in the field for abnormality, particularly for

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1 signs of thermo mechanical bending development.
2 Following the field examination, several samples were
3 selected and were sent for detailed analysis at various
4 independent cable laboratories, specializing in pipe-
5 type cable. The laboratory analysis has not been
6 completed. The removal and laboratory analysis of a
7 second cable section was originally planned for 2009
8 and was deferred to 2010. Staff now proposes to
9 further defer this project to 2011. While the Company
10 does not oppose deferral to 2011, the Company is
11 concerned that the Transmission Feeder Failure program
12 be adequately funded for two section failures pending
13 more definitive analytical results regarding the future
14 performance of 345 kV Feeder M51. In addition, in
15 2009, the Company will be removing three sections of
16 138kV high pressure pipe type cable under the project
17 titled "Replacement of Feeders 18001 & 18002", as
18 described in IIP-4, p. 94. These feeders were
19 installed in 1949 and have become increasingly prone to
20 failures. There have been a total of eleven failures
21 on these two feeders since 2000. A similar type field
22 inspection and laboratory analysis is planned for cable
23 on Feeder 18001 to assess its condition to ensure the

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1 continued reliability of the transmission system. The
2 Feeder Failure program needs to be adequately funded
3 for two section failures pending more definitive
4 analytical results regarding the future performance of
5 Feeders 18001 and 18002.

6 There are other emergency circumstances which may
7 require that a cable section be replaced. For example,
8 a replacement may be performed if external contaminants
9 enter the dielectric fluid system caused by a water
10 main or water service leak.

11 EMS Reliability AECC and ECC (SIIP, p. 67) Con Edison
12 proposes a funding level of \$0.5 million for 2010 and
13 \$1.0 million for 2011. Staff proposes no funding in
14 2010 and \$1.0 million in 2011. Staff erroneously
15 states (SIIP, p. 10) that the Company's revised 2009
16 budget deferred spending on this project from 2009 to
17 2010. Staff's Exhibit __ (SIIP-2), p. 3, clearly shows
18 that the Company's original 2009 budget contained no
19 spending for this program. Further, this program was
20 not addressed in the May 26, 2009 austerity-related
21 filing.

22 Staff's proposed adjustment is a good example of the
23 potential adverse impacts of proposing an adjustment on

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1 the grounds of "low-priority" without examining the
2 underlying need for the expenditure. This project,
3 described in Exhibit IIP-7, page 15, addresses the need
4 to maintain the new Energy Management System (EMS)
5 operating system hardware and software at a required
6 release level that is fully supported by the primary
7 vendor, and all third party suppliers. Maintaining the
8 EMS near current release levels is a necessity. The
9 system currently installed is a release 9.0 product
10 while the vendor is currently providing release 12 to
11 the industry. In order to maintain the ability to
12 install security patches for this cyber asset, an
13 operating system release upgrade will need to be
14 performed. The inability to patch the system will
15 subject the Company to monetary fines if compliance to
16 NERC standards cannot be accomplished. In addition,
17 enhancements of EMS operator tools become more costly
18 as the operating system ages. Deferrals of 2010 funds
19 will increase the annual funding requirement in the
20 outer years to allow for the necessary upgrades to be
21 completed. The proposed elimination of funding in 2010
22 would require 2011 funding to be increased above the
23 Company's proposed \$1 million in 2011 to allow for

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1 necessary operating system changes.
2 Outage Scheduling System (SIIP, p. 67) Con Edison's
3 revised 2009 budget reduced funding for this project
4 from \$3.0 million to \$1.0 million. The Company
5 continues to propose expenditure of \$3 million in 2010.
6 Staff proposes that the \$1.0 million funding level
7 continue through 2010, and Staff makes no proposal for
8 spending in 2011.
9 The proposed reduction for the Outage Scheduling System
10 from \$3.0M to \$1.0M in 2010 will limit the project
11 scope and inhibit the implementation of the
12 functionality, productivity and efficiency objectives
13 discussed in Exhibit IIP-7, p. 18. The request for the
14 Outage Scheduling System involves the development of
15 significant enhancements and upgrades to the existing
16 system that will result in significant additional
17 functionality and productivity. The system is used by
18 all entities requesting to schedule equipment outages
19 on the transmission and distribution electric system.
20 The Outage Scheduling System enhancements will
21 streamline the process by, among others: a) automating
22 key scheduling sub processes that are currently overly
23 dependent on people interactions and manual

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1 manipulation, such that the planning, sequencing and
2 scheduling of outages will be performed with increased
3 accuracy and efficiency; b) setting up outage schedule
4 viewing and graphing capabilities that will help all
5 stakeholders to review the same depth and breadth of
6 outage information therefore facilitating better
7 coordination and the consolidation of outages; c)
8 tracking, flagging, notifying and reporting on
9 compliance communications on outages with various
10 outside entities. The requirements for these
11 communications are evolving at a fast pace and cannot
12 be met by the current system. The reduced level of
13 funding will jeopardize our ability to meet our
14 compliance requirements related to NYISO outage
15 notifications.

16

17 Q. Has Staff provided any support for its adjustment?

18 A. No. Staff's adjustment relies on the bare assertion
19 that this project is "low-priority" and fails to
20 address why Staff believes these benefits should
21 continue to be postponed. The Company is implementing
22 this project and has spent \$760,000 in 2009 through
23 August. While the Company believed it reasonable to

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1 defer \$2 million in project expenditures for one year
2 in 2009, the Company believes that further deferral of
3 this project and its benefits is not reasonable.
4

5 Q. Please discuss Staff's proposal regarding the Re-
6 Conductor Dunwoodie-Sprainbrook Transmission Corridor
7 (SIIP, p. 68).

8 A. We do not oppose Staff's proposal for 2010 and 2011
9 expenditures, but wish to clarify the impact of this
10 proposal on 2012 expenditures. Con Edison proposes to
11 spend \$500,000 in 2010 and \$5.4 million in 2011. Staff
12 proposes no funding for 2010 and allows \$5.4 million in
13 2011. This capital program involves two major 138kV
14 feeder outages which are scheduled in the 4th quarter
15 of 2011. The materials need to be purchased in
16 advance. Since the \$500,000 scheduled for this project
17 in 2010 is for purchasing material, the purchase can be
18 deferred to 2011 with minimal impact. However, if
19 Staff's proposal were to be accepted, \$500,000 will be
20 required in 2012 to complete the scope of planned work
21 in 2012. Staff proposes "deferring the project an
22 additional year" and we take this to mean that Staff
23 does not oppose expenditure of \$500,000 in 2012 to

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1 complete this project.

2

3 Q. Does that conclude your discussion on the S&TO projects
4 and programs proposed reductions by Staff?

5 A. Yes. Next we will discuss our objections to Substation
6 reductions by Staff listed on Exhibit _ (SIIP-2) page
7 5.

8

9 Substation Operations

10 Q. Have you reviewed Staff's testimony with regards to the
11 Area Substation Reliability and Auto Ground Switch
12 Program? (SIIP, pp. 42-44)

13 A. Yes. Staff proposes to reduce expenditures from the
14 Company's proposed funding of \$10.5 million in 2010 and
15 2011 to \$6.493 million each year.

16

17 Q. Do you agree with Staff's recommendation regarding this
18 program?

19 A. No. As described in Exhibit IIP-4, pp. 38-39, this
20 program plays a vital role in improving the reliability
21 of the distribution system by reducing the probability
22 of losing multiple area station transformers due to
23 station low side (13 kV, 27 kV and 33 kV) faults. The

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1 \$10.5 million requested will allow the Company to
2 maintain a consistent level of construction work and
3 schedule within system outage constraints that will
4 allow us to continue implementation of the reliability
5 work at about 5-7 transformers per year. This will
6 allow us to complete this work at all of the stations
7 where it is required within approximately 12 years.
8 Installing high side clearing device involves
9 structural modification to our existing substations
10 which, for the most part, were not designed to
11 accommodate the additional equipment. This adds to the
12 complexity and cost of the work. Also, it is important
13 to note that the Automatic Ground Switches (AGS)
14 retirement program has now been combined with the
15 reliability program, since the AGS can only be retired
16 if an alternate high side clearing device is installed
17 in its place. Circuit switchers or digital transfer
18 trip schemes are installed as part of this program to
19 provide fault clearing capability in the event of a low
20 side fault. These new circuit switchers or digital
21 transfer trip schemes replace the antiquated automatic
22 ground switches that are a source of SF6 (a greenhouse
23 gas) leakage. The AGS have obsolete components, are no

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1 longer supported by the original equipment
2 manufacturers, and their SF6 leaks are increasing.
3 Therefore, reduction in this overall program will also
4 impact the AGS program.
5 In addition, Staff's adjustment will reduce the ability
6 to maintain a consistent level of construction for this
7 program. Staff's recommendation to reduce this program
8 by \$3.86 million annually will reduce the number of
9 installations to no more than 3 per year, which will
10 result in further delay of the program completion.
11 Past progress on this program has been hampered by
12 outage and resource constraints - primarily in the area
13 of Company resources available to perform the work
14 planned. With the redirecting of Company work forces
15 from new Substation building projects, which have been
16 deferred to later years, the Company is expected to
17 focus on working multiple boroughs simultaneously with
18 the Company resources available. The decrease in major
19 project activity is also expected to provide more
20 flexibility in our ability to obtain the outages
21 necessary to perform this work. Furthermore, the
22 Company has to date appropriated and is in the process
23 of ordering the equipment for multiple stations to

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1 ensure equipment will be on hand to be able to meet the
2 installation goals for this program for the next three
3 rate years. Engineering has assigned a Project
4 Engineer along with multiple discipline engineers to
5 support the program, and is working aggressively to
6 produce construction and installation packages for
7 equipment planned for installation during the coming
8 years. The combination of more effective coordination
9 between the Program Manager and Project Engineer,
10 increased outage flexibility, and increased
11 availability of field forces to perform this work will
12 enable us to meet our goals.

13

14 Q. Do you agree with Staff's assessment of the Facility
15 Improvement Program and their recommendation regarding
16 it? (SIIP, pp. 44-46)

17 A. No. Staff proposes to reduce expenditures from the
18 Company's proposed budgets of \$6 million in 2010 and in
19 2011 to \$3.72 million each year. As noted in the
20 Company's Exhibit IIP 4, pp. 57-60, this program funds
21 facility improvements and upgrades, such as facility
22 structural improvements related to facade, foundations,
23 retaining walls, HVAC, lighting and plumbing, and large

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1 scale drainage modifications. In addition, Substation
2 Operations has various office facilities that are
3 temporary in nature, housing numerous employees on a
4 daily basis. Additional work space in existing
5 facilities must be created or these temporary
6 facilities must be replaced with permanent facilities
7 that meet all applicable building codes. The Company
8 has increased the budgeted funding level for the
9 facilities upgrade program in recent years in light of
10 identified physical facility deterioration and aging
11 infrastructure concerns. Staff's proposed reduction in
12 funding for this program based solely on an historical
13 analysis of actual expenditures does not recognize the
14 change in priority or magnitude of planned future
15 upgrades. Con Edison's response to DPS 406 (Staff
16 Exhibit SIIP-1, pp. 147-60) discusses the actions that
17 the Company has taken to assure that the Company's
18 spending goals are met. These actions include not only
19 the appointment of a program manager, whose importance
20 Staff's testimony gratuitously dismisses, but also a
21 program engineer whom Staff fails to even acknowledge.
22 These managers assist in the coordination of the work
23 and verify that program goals are met. They coordinate

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1 regular meetings and timely coordination between
2 Engineering, Substations, and Construction groups to
3 track project deliverables.
4 Furthermore, we take exception to Staff's assertion
5 that we are on pace to spend only \$3.72 million in
6 2009, based simply on our year-to-date spending through
7 July. This assertion completely overlooks the fact
8 that many of the projects planned to be done under this
9 program were always planned to start in the late Summer
10 and Fall of this year. Con Edison's response to DPS
11 406 (Staff Exhibit SIIP-1, pp. 147-60) shows a variety
12 of substantial projects that are scheduled to start in
13 that timeframe and are expected to be completed this
14 year. The Company's response to DPS 406 provided
15 project-by-project expenditure projections totaling \$8
16 million and stated that "spending for this program is
17 expected to meet the 2009 budget". In addition, the
18 Company's response to DPS 406 itemizes projects
19 totaling an additional \$17 million that are expected to
20 be completed in 2010 and/or 2011. And, as stated in
21 Exhibit IIP-4, p. 58, our experience is that additional
22 projects continue to emerge for evaluation and scoping.
23 Based on the importance of these projects and the

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

ELECTRIC

1 readiness of the Company to proceed with these projects
2 in the near term, it is particularly inappropriate to
3 reduce funding for these projects based solely on an
4 analysis of historical expenditures and an erroneous
5 projection that substantially understates projected
6 2009 expenditures. The Company's current end-of-year
7 expenditure estimate for this program is \$6.4 million.
8 The Company's proposed funding level of \$6 million per
9 year is consistent with the nature and scope of the
10 work that has been identified and planned under this
11 program. Staff's proposed reduction from \$6 million to
12 \$3.72 million would result in significant delays to
13 projects that directly affect substation facility
14 reliability and to projects needed to upgrade systems
15 and components in order to meet code requirements. In
16 addition, as a result of a reduction of this magnitude,
17 a number of other important projects would be deferred
18 for several years.

19

20 Q. Do you disagree with any of Staff's other
21 recommendations?

22 A. Yes, we disagree with Staff's recommendations to
23 continue funding at the 2009 austerity levels for the

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1 following Substation Operations Programs: Pumping Plant
2 Improvement Program, Substation Loss Contingency
3 Program, and Substation Target Information System (TIS)
4 Program.

5
6 Q. Please discuss the Pumping Plant Improvement Program
7 (SIIP, p. 69-70).

8 A. We disagree with Staff's recommendation for funding the
9 Pumping Plant Improvement Program at \$5.5 million per
10 year for the years 2010 and 2011. The requested \$8.5
11 million funding levels for this program in 2010 and
12 2011 are consistent with the proposed scope of work for
13 future years. As discussed in great detail in Exhibit
14 IIP-5, pp. 7-10, this program funds upgrades to several
15 aspects of the Company's dielectric facilities that are
16 critical to the operation of the underground
17 transmission system including pumping, cooling and PURS
18 plants, dielectric facility control/alarm panels, and
19 pump house connectivity and performance monitoring.
20 The requested level of funding for this program is
21 designed to ensure that both previously identified and
22 emergent projects, as well as important dielectric
23 system improvements are addressed in a timely manner

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1 thereby mitigating the risk of events that could result
2 in environmental impacts and ensuring safe and reliable
3 transmission line operation. Staff's proposed
4 reduction of \$3 million per year will delay
5 implementation of planned projects that directly
6 support the reliability of the transmission system.
7 The Company's proposed funding level of \$8.5 million
8 per year is consistent with the scope and priority of
9 planned upgrades.

10 We note that, quite correctly, Staff refrains from
11 describing the Pumping Plant Improvement Program as a
12 "low-priority" program. However, Staff's statement
13 that reducing funding by \$3 million per year will
14 "extend[ing] the time necessary to complete this
15 project" leads us to conclude that Staff may have
16 misunderstood the nature and importance of this
17 program. This program is not a project with an end
18 date that will be deferred a year or two by Staff's
19 proposal. Rather, this program provides for the
20 ongoing vitalization and replacement of critical
21 transmission support systems that are aged and often
22 obsolete and/or unreliable, have antiquated controls,
23 and are often unsupported by manufacturers and parts

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1 suppliers. The key to maintaining these facilities is
2 consistent upgrades to the wide variety of equipment
3 needed to assure reliable and environmentally safe
4 operation. Reducing this investment by 35% in 2010 and
5 2011, after a reduction of 35% in 2009 to address
6 austerity concerns, unwisely increases an already
7 growing backlog of necessary work and degrades the
8 reliability of the transmission system.

9

10 Q. Please discuss Staff's proposed adjustment to the
11 Substation Loss Contingency Program (SIIP, p. 69).

12 A. We disagree with Staff's proposal to reduce
13 expenditures on the Substation Loss Contingency Program
14 from \$2 million in 2010 and in 2011 to \$1 million in
15 each year. This project will facilitate the Company's
16 capability to respond to reduction of load and
17 transmission capacity and loss of service to customers
18 in the event of the loss of a transmission substation.
19 This will be accomplished by purchasing spare
20 substation and transmission equipment such as cable
21 sections, joints, portable relay panels, current
22 transformers, etc. The items to be purchased have been
23 identified as key, long-lead-time items required to

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1 support various restoration plans that have been
2 developed by the Company to respond to a catastrophic
3 event such as a terrorist attack or hurricane. The
4 Company is presently in the process of purchasing the
5 first of three portable relay house enclosures, and had
6 planned to purchase the remaining two in 2010. Staff's
7 recommendation to reduce funding for this program from
8 \$2 million to \$1 million will result in the need to
9 defer the delivery of the last of these units until
10 2011. In addition, at this reduced funding level,
11 procurement of other equipment or material identified
12 as key long-lead items associated with these
13 restoration plans would not be able to start until
14 after 2011 as well. The Company's proposed funding
15 level of \$2.0 million per year is consistent with the
16 scope and priority of planned procurement actions. It
17 is one thing to defer spending of \$1 million for a
18 limited one year period, as per the Company's 2009
19 austerity plan. It is quite another thing to continue
20 inadequate expenditures over two additional years given
21 the consequences of the loss of a transmission station.
22

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE
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1 Q. Please discuss Staff's proposal to continue the
2 Substation Automation Target Information System (TIS)
3 Program at 2009 austerity levels into future years
4 (SIIP, p. 70)?
5

6 A. The Company proposes to fund the Substation Automation
7 Target Information System (TIS) Program at \$2 million
8 in 2010 while Staff proposes funding of \$1 million each
9 year. The. This Program installs leading edge
10 technology at substations to support reliability,
11 safety, and equipment availability goals. The critical
12 equipment operating data, such as high voltage circuit
13 breaker timing, provided by this state-of-the-art
14 system is an important component of the Company's
15 strategy to transition maintenance practices from a
16 time-based maintenance schedule to a condition-based
17 maintenance philosophy in order to reduce equipment
18 maintenance costs and improve equipment availability
19 and reliability. This system will also provide the
20 ability to remotely and accurately access real time
21 electrical system parameters and to automatically
22 receive reports by exception when there are problems
23 with monitored equipment. The \$2 million funding level

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1 will cover sensors, recorders, and a new fiber optic
2 LAN Infrastructure and communication interface. This
3 will enable the acquisition of electrical information
4 from the sensors and recorders and route them from the
5 various substation relay houses to the substation
6 control room, for data storage and viewing. In
7 addition, smart data concentrators, Ethernet switches,
8 and new computer servers will be installed to complete
9 the system. The substation servers will be connected to
10 a master server at the Company's headquarters in
11 Manhattan utilizing the corporate LAN. This will enable
12 remote sharing of TIS information to different users.
13 The Company's proposed funding level of \$2.0 million
14 per year is appropriate and supports this objective.
15 Staff does not oppose this program, but its proposed
16 funding level will needlessly delay the benefits that
17 this state-of-the art technology will provide.

18

19 Q. Does that conclude your discussion on Substation
20 Operations proposed funding reductions by Staff?

21 A. Yes. Next we will discuss Staff's proposed reductions
22 to Electric Operations beginning on page 6 of Staff's
23 Exhibit _ (SIIP-2).

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

ELECTRIC

1

2 **Electric Operations**

3 Q. Please identify the proposed reductions that you
4 oppose.

5 A. We do not agree with Staff's proposal to continue
6 reductions to the following Electric Operations
7 programs based on the 2009 revised budget:

8

9 Transformer Purchase Program (SIIP, pp. 72-73) As a
10 result of the Company's austerity reduction, the 2009
11 revised budget reflected a \$14 million reduction to the
12 Transformer Purchase Program. Staff proposes to
13 continue the \$14 million reductions in both 2010 and
14 2011. The Company is effectuating the \$14 million
15 reduction in 2009 by reducing the available inventory
16 of transformers and related equipment at the end of the
17 year. The Company classified the \$14 million as a 'low
18 priority' because reducing inventory at the end of the
19 year is a low risk since the end of the year is after
20 the summer high load and hurricane and tropical storm-
21 induced flood periods and, therefore, the risk of
22 needing emergency inventory is reduced. In addition,
23 the Company will closely monitor the inventory, and

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ELECTRIC

1 manage the scheduled installations required at the end
2 of 2009 to minimize the risk of the reduction.
3 However, the Company planned to quickly restore its
4 inventory at the beginning of 2010 so that the Company
5 can complete its programs that prepare for the summer
6 period and reinstate the inventory level required for
7 emergency response. As importantly, as discussed in
8 the supplemental testimony of Mr. Rasmussen, the 2009
9 austerity measures were intended to be permanent and
10 the Company does not include an incremental \$14 million
11 in its 2010 budget to pay for the restoration of
12 equipment levels. Accordingly, the Company's
13 transformer purchase budgets of \$144.6 million for 2010
14 and \$138.6 million for 2011 reflect the use of the same
15 year-end inventory reduction strategy as used at the
16 end of 2009. Thus, Staff's proposed reductions of
17 additional \$14 million reductions in 2010 and in 2011
18 would result in a cumulative reduction to distribution
19 equipment inventory of \$28 million in 2010 and \$42
20 million in 2011 and would jeopardize our ability to
21 meet equipment requirements.
22 There can be no question that the Company is required
23 to maintain inventory to support distribution system

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1 growth, relief, reliability, and emergency restoration
2 of failed equipment. See Exhibit IIP-4, pp. 162-165.
3 Since the Company purchases unique equipment for our
4 network system, the Company is unable to obtain our
5 equipment from other utilities during emergencies. In
6 addition, only a limited number of manufacturers can
7 produce our equipment, and we experience long lead
8 times on deliveries. The cumulative effect of Staff's
9 proposed reduction to Transformer Purchase in 2010 and
10 2011 will negatively impact our ability to replace
11 failed and undersized equipment and proactively replace
12 poorly performing equipment. Thus, Staff's proposal
13 would decrease the safety and reliability of the
14 system.

15 Underground Secondary Reliability Program (SIIP, p. 71)
16 The Company plans to spend \$37.4 million in 2010 and
17 \$40.8 million in 2011 to replace secondary cable in the
18 underground secondary network system. The Company
19 disagrees with Staff's proposal to spend only \$24.2
20 million in each year. Staff provides no program-
21 specific opposition in support of its reduction. Staff
22 claims that the Company's identification of this
23 program as "low priority" in 2009 warrants continued

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1 reductions in 2010 and 2011. As explained in Exhibit
2 IIP-4, pp. 148-150, this program is critical for
3 preventing cable failures in the underground secondary
4 grid, and the Company has made expenditures in past
5 years substantially in excess of Staff's proposed \$24.2
6 million level (\$28.8 million in 2005, \$59.3 million in
7 2006, \$44.1 million in 2007, and \$33.6 million in
8 2008). The Company reduced the funding for this
9 program in 2009 was based on the premise that in 2010,
10 the Company will resume the normal level of cable
11 replacements under this program. As discussed in
12 Exhibit IIP-4, p. 149, the volume of secondary cable
13 (mains and services) replacements identified by the
14 inspection program in 2008 and 2009 has increased
15 substantially. With the first five-year inspection
16 cycle completed in 2009, additional qualified resources
17 are available in 2010 and 2011 to begin to reduce the
18 substantial backlog of work. The funding level
19 proposed by Staff is inadequate to support the
20 Company's plans to work down the backlog.
21 Auto Loop Reliability Program (SIIP, p. 73) In 2009,
22 the Company, as part of its austerity plan, reduced
23 funding for this program from \$6.1 million to \$3.1

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1 million, as a one year deferral. The Company plans to
2 spend \$7.3 million and \$7.5 million on auto-loop
3 projects in 2010 and 2011, respectively. Staff
4 proposes to maintain a \$3.1 million expenditure level
5 in 2010 and 2011, thereby "extending the time necessary
6 to complete this multi-year project." Staff's
7 recommendation would cause a multi-year deferral of a
8 number of projects that were specifically aimed at
9 mitigating the risk of extended outages for customers
10 on high summer-load days and reducing the Company's
11 non-network CAIDI index performance. In addition, with
12 Staff witness Jones' proposal in this proceeding to
13 substantially reduce the non-network SAIFI RPM target,
14 the Company's planned auto-loop improvements will help
15 the Company meet a stricter target, should one be
16 adopted.

17 The proposed cuts represent a 58% reduction in the
18 funding for the work Con Edison had planned to do in
19 2010 and 2011 to mitigate identified risks.

20 In particular, the Coney Island Loop in Brooklyn has
21 suffered a number of large outages in the past 4 years
22 as follows:

23 Date # of customers interrupted

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1	8/21/05	11856
2	8/22/05	7440
3	8/9/07	7638
4	4/25/08	7638
5	9/2/08	7750

6

7 The average SAIFI for customers on this loop since

8 January 1, 2006 has been 1290 outages per 1000

9 customers per year which is significantly higher than

10 the present SAIFI target of 530 and the 470 target

11 proposed by Staff witness Jones. The Coney Island Loop

12 currently supplies 8,850 customers and over 20,000kVA

13 of peak load. In addition to the poor historic SAIFI,

14 a major concern for this loop is an extended duration

15 outage for almost all of the customers if the two (2)

16 normal supply feeders are lost during a high load

17 period. The Company has plans to split the Coney

18 Island Loop and create the new Cropsey Loop, by running

19 two new feeders. Not only will this halve the number

20 of customers on each loop, and between reclosers, which

21 would halve the number of customers affected for main

22 run feeder faults, it will also provide back-up feeders

23 to supply the new Cropsey Loop should its two normal

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1 feeders be out of service. However, with Staff's
2 proposed budget reductions for 2010 and 2011, the
3 Company will not have the funds to complete even this
4 single project, which is estimated to cost \$8 million,
5 until 2012.

6 Staff's proposed reductions will have the effect of
7 deferring the start date for all the other work listed
8 in Exhibit IIP-4, pp. 175-178, including the
9 Bronx/Westchester '3rd Feeder' and the Staten Island
10 'URD Tie Points' program until 2012, with the vast
11 majority of the work outlined in the exhibit not being
12 able to be completed until after 2012.

13 A single loop supply feeder outage has the potential to
14 affect thousands of customers and substantially
15 influence the Company's annual non-network CAIDI index.
16 More than any other Company program, the Autoloop
17 Reliability projects outlined in the exhibit mitigate
18 this risk. As an example, the Dyker Loop (another
19 project listed in the exhibit) in its present
20 arrangement has over 15,000 customers. In 2008, the
21 year-end system-wide non-network CAIDI was 1.83 hours
22 which just met the RPM target of 1.85 hours. If the
23 15,000 Dyker Loop customers had an outage of 6 hours in

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1 2008, the system-wide non-network CAIDI for 2008 would
2 have been 2.00 hours - a 10% increase over the actual
3 2008 result.
4 Overhead Feeder Sectionalizing Program (SIIP, p. 73)
5 In 2009, the Company, as part of its austerity plan,
6 reduced funding for this program from \$2.6 million to
7 \$2.3 million, as a one year deferral. The Company plans
8 to spend \$3.1 million and \$3.2 million on overhead
9 feeder sectionalizing projects in 2010 and 2011,
10 respectively. Staff proposes to maintain a \$2.3
11 million budget level in 2010 and 2011. Staff's
12 recommendation will defer significant outage
13 interruption and duration reductions as well as safety
14 benefits that would not be realized because of this
15 effective 28% cut in funding. The missed opportunities
16 that would not be realized are as follows.
17 As outlined in Exhibit IIP-4, pp. 182-186, half of the
18 requested funding is for the addition of Automatic
19 Reclosers to 4kV feeders. There are presently 180 4kV
20 station-to-station feeders without these state-of-the
21 art automatic switches. The proposed reduction will
22 fund only 22 automatic switches in 2010, instead of the
23 32 now planned for high priority 4kV circuits. For the

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1 ten high priority 4kV circuits that would not be
2 installed in 2010, a fault on the main feeder run will
3 interrupt service to 100% of the customers supplied,
4 instead of 17% to 50% if an automatic sectionalizing
5 switch had been installed. In addition, an automatic
6 sectionalizing switch also helps detect and de-energize
7 downed 4kV conductors that may otherwise have remained
8 alive. This provides a significant public safety
9 benefit.

10
11 Of the requested \$3.189 million funds, \$850,000 (27%)
12 are for the installation of Automatic Reclosers as mid-
13 points on 13kV auto-loops. Presently, 120 locations
14 within 13kV auto-loops do not have mid-point reclosers.
15 With Staff's proposal, only 12 of these state of the
16 art automatic switches will be installed in 2010
17 instead of the 17 now planned. A fault on the main run
18 of an auto-loop without a mid-point recloser switch
19 will interrupt service to 100% of the customers on that
20 half of the loop, instead of only 50% if the feeder had
21 a mid-point recloser switch installed.

22 A further \$490,000 (15%) of the funds for this program
23 in 2010 will be used to install manual switches on

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1 poorly performing fused spurs. The installation of a
2 manual switch provides the ability to restore service
3 to the majority of customers affected by equipment
4 failure before making the repair. These installations
5 are specifically targeted to circuits having high
6 outage rates and will reduce customer outage duration
7 and impact overall non-network CAIDI in a significant
8 and positive manner. Staff's proposed 30% reduction
9 for this portion of the program will simply result in
10 longer restoration times for the very customers that
11 already receive a disproportionately poorer service.
12 Rear Lot Pole Replacement (SIIP, p. 73) In 2009, the
13 Company, as part of its austerity plan, decided to
14 reduce funding for this program from \$1.437 million to
15 \$0.437 million, as a one year deferral. The Company
16 plans to spend \$1.437 million on replacing rear lot
17 distribution systems in both 2010 and 2011. Staff
18 proposes to maintain a \$0.437 million expenditure level
19 in 2010 and 2011. Staff's 70% reduction will cause a
20 multi-year deferral of projects that are specifically
21 aimed at mitigating the risk of extended outages for
22 customers fed from rear lot distribution systems. The
23 proposed reductions will delay the replacement of many

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1 of the eleven rear lot distribution lines already
2 identified as ready to work with layouts drawn.
3 As stated in Exhibit IIP-4, pp. 189-190, once these
4 facilities fail, replacement is extremely difficult and
5 time consuming such that customer outages are extended
6 resulting in inconvenience to customers. In addition,
7 in many cases, customer structures have blocked access
8 to these facilities so that maintenance cannot be
9 performed. In some cases, one side of the supply is
10 already out of service, and the next failure will
11 result in outages for the customers on the affected
12 line. The Company's pro-active rear lot distribution
13 program corrects these conditions before they result in
14 a significant outage or public safety concern. Staff's
15 proposed reductions will inhibit the Company's efforts
16 to address these conditions.

17 Meter Shop Adams (SIIP, p. 75) The Company's revised
18 2009 budget deferred the start of this project by one
19 year to 2010 and eliminated the \$750,000 expenditure
20 planned for 2009. The Company continues to propose
21 expenditure of \$2.75 million in 2010 and \$1 million in
22 2011. Staff recommends that the project be deferred
23 for an additional two years with no funding in 2010 and

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1 2011 mainly because they consider it an upgrade to a
2 working system. As discussed thoroughly in the
3 Company's Exhibit IIP-7, pp. 42-43, this project will
4 completely replace, not upgrade, the current, obsolete
5 system that is severely challenged in its ability to
6 meet current, let alone future, operating and
7 regulatory requirements. This project is critical to
8 the Company's ability to meet the fundamental record-
9 keeping requirements established by Part 92 of the
10 Commission's Rules. The current ADAMS system was
11 designed more than two decades ago when metering
12 inventories and requirements were limited by the
13 technology and consumer applications of that era. The
14 programming language used dates back even further and
15 was designed around the use of paper forms for the
16 technicians and administrative personnel to record work
17 information related to meter tracking activity. The
18 current ADAMS system no longer meets our needs and can
19 no longer be considered a "working system" based on the
20 technology of the metering products we must track as
21 well as the complexity of the data systems that ADAMS
22 must interface with. The next two years are expected
23 to present significant advances in metering technology

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1 relative to AMI and Smart Grid initiatives. The
2 current ADAMS system, which has already failed to keep
3 up with our present needs, will severely impact our
4 ability to field new technology required to provide our
5 customers the most advanced metering equipment for
6 their benefit. Staff's proposed deferral should be
7 rejected.

8 Electric Distribution Control Center Upgrades (SIIP,
9 pp. 75-76) The Company's revised 2009 budget reduced
10 expenditures on this project from \$3 million to
11 \$500,000 to meet austerity requirements. The Company
12 continues to propose expenditure of \$3 million in 2010
13 and in 2011. Staff recommends that expenditures be
14 limited to \$500,000 in 2010 and in 2011. Staff's
15 proposed reduction would seriously impede our ability
16 to proactively replace unsupported computing
17 infrastructure and undersized UPS (Uninterruptable
18 Power Supplies,) and preempt failure of the core
19 engineering analysis systems that are operated in the
20 control systems. Such failures would degrade the
21 Company's ability to maintain system reliability and
22 the Company's ability to respond to emergency system
23 conditions. The continuation of the \$2.5 million

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1 reduction in 2010 and 2011 will put the Company's
2 electric control centers at a severely reduced level of
3 supportability. As stated in the Company's Exhibit
4 IIP-7, pp. 54-55, by 2011, most of the existing
5 computing infrastructure in the control centers will no
6 longer be supported by HP (no technical support, no
7 security patches, no software upgrades). This continued
8 lack of supportability will create further issues
9 associated with supporting additional projects such as
10 Smart Grid and the High Tension Monitoring System.
11 Both critical engineering applications and systems will
12 be in jeopardy by the inability to upgrade the systems.
13 Also security patches would not be provided. Staff's
14 recommended \$500,000 per year is insufficient to fund
15 even the \$750,000 cost of the UPS needed to replace the
16 system that failed in the Manhattan Control Center last
17 June. The MCC is operating on the backup system with
18 an undersized system as the current backup. Other
19 concerns that are addressed by this project, as
20 discussed in the exhibit, include replacement of
21 hardware running critical engineering applications that
22 is nearing the end of useful life, isolation of control
23 center systems for cyber attack, re-engineering and

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1 back-up of the overloaded UPS systems, and installation
2 of advanced high speed network interconnections needed
3 to propagate the enormous data requirements of the
4 Company's systems. Staff's proposed funding levels are
5 entirely inadequate to address the critical upgrade
6 requirements for the distribution control centers in a
7 timely manner.

8

9 Q. In addition to some of Staff's proposed reductions
10 based on the Company's 2009 austerity plan, do you
11 agree with the other recommended reductions by Staff?

12 A. The Company can go along with the recommendations by
13 Staff for the following programs: Isolation
14 Transformers, Aerial (Okonite) Cable replacement, and
15 C-Truss.

16

17 Q. Please discuss the other Electric Operations program
18 reductions proposed by Staff that the Company opposes.

19

20 A. We do not agree with the following reductions proposed
21 by Staff:

22 Secondary Open Mains (SIIP, pp. 51-53) The Company
23 proposes to spend \$139.2 million in 2010 and \$129.8

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1 million in 2011 for emergency repair work to address
2 secondary network main (cable) failures. Actual
3 expenditures were \$138.9 million in 2007 and \$137.5
4 million in 2008. In 2009, the Company has spent \$100.7
5 million through August and projects expenditures of
6 \$132.7 million to year end. Staff proposes
7 expenditures of \$120 million in 2010 and in 2011.
8 Staff asserts that secondary main failures are in part
9 related to load on the secondary system and because
10 Staff witness Liu argues that the Company has
11 overstated its system wide load forecast by 200 to 225
12 MW in 2010 and 2011 the Company's projected
13 expenditures for this program are overstated. Staff's
14 proposed adjustment is entirely without merit.
15 To begin, Staff provides no support for how it derived
16 its 13.7% reduction in 2010 and 7.5% reduction in 2011.
17 Staff states that \$120 million recommendation
18 approximates 2006 actual expenditures (\$118.8 million).
19 Staff fails to demonstrate any correlation between
20 actual expenditures for open mains repair and system
21 peak load. The Company's expenditures versus system
22 peak load has been as follows:

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Year	System Peak Load (MW)	Open Mains Expenditures (\$000)
2005	13,059	\$104.9
2006	13,141	\$118.8
2007	12,807	\$138.9
2008	12,987	\$137.5

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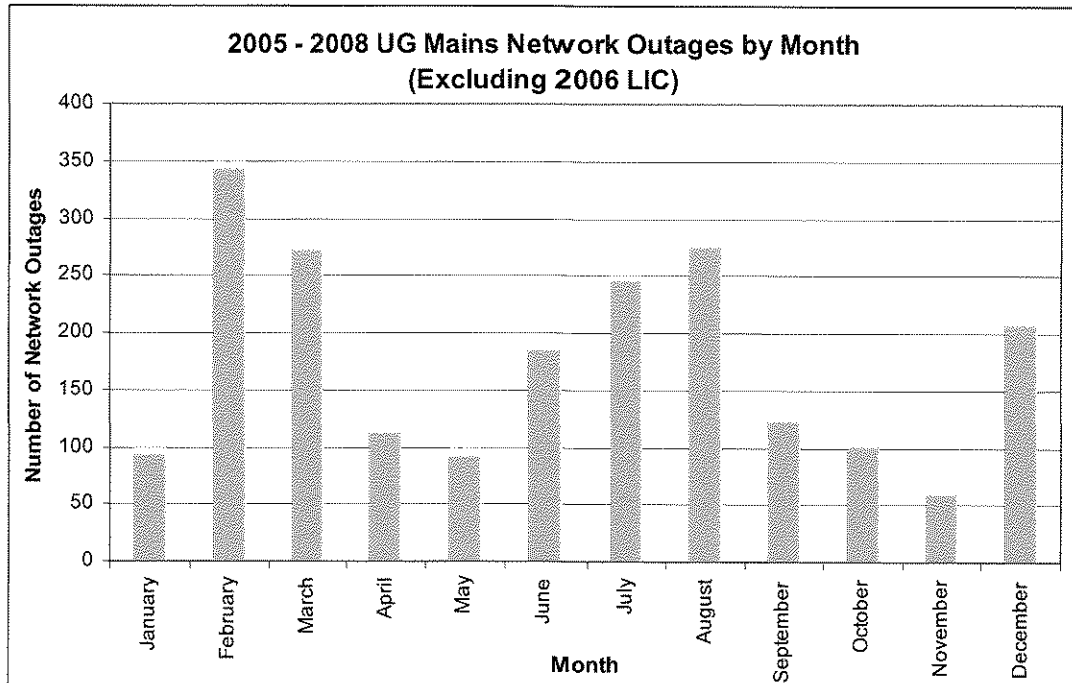
15

In addition Staff's proposed adjustment for open mains repair is a double count with Staff's proposed \$100 million global T&D expenditure reduction that is also intended to reflect Staff's Witness Liu demand level forecast for 2010 and 2011.

There are many other reasons other than loading that may cause a secondary open main. Secondary open mains are often caused by cable insulation breakdown which occurs due to aging, salt water intrusion, and contact with the structure. Secondary failures occur throughout the year, and as demonstrated by the chart below, the highest volume occurs during winter months as a result of winter snow and ice events and salt spreading.

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Staff's conclusion (p. 53) that the secondary open mains program is a "demand related program" is incorrect. Secondary mains open for multiple reasons beyond loading as observed by the average number of open main receipts annually. As shown above, the Company observes more open mains during non summer months when the demand is low compared to the summer months when the demand is much higher.

The Company has evaluated the impact of Staff's proposed reductions, which total \$29 million. Such a reduction would negatively impact the Company's ability to make the necessary repairs involving cable

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1 replacement, cable joint replacement and related
2 conduit work, and would increase the back log of open
3 mains at the end of each year. On average, the unit
4 cost per section replaced, including conduit work and
5 street excavations, is \$20,000. At this average unit
6 cost, a \$29 million reduction translates to an addition
7 1,450 sections of open mains added to the back log.
8 With a historical average of 1,791 open mains pending
9 at year end, the back log would be approximately 3,200
10 representing approximately an 80% increase. A rapid
11 increase in the back log due to the proposed reductions
12 would have a significant negative impact on the
13 integrity of the secondary network system. These
14 replacements are critical to maintaining service
15 continuity to the Company's network customers. Staff's
16 proposed reduction to the Secondary Open Mains program
17 will significantly impact our ability to replace open
18 mains.

19 Shunt Reactors (SIIP, pp. 53-55) The Company proposes
20 to spend \$2.7 million in 2010 and in 2011 for shunt
21 reactor installations. Staff proposes expenditures of
22 \$1.05 million in 2010 and in 2011. Based on the
23 Company's three shunt reactor installations through

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1 July 2009 at a cost of \$525,000, Staff predicts six
2 installations through the end of the year at a cost of
3 \$1.05 million. Pointing out that the Company installed
4 a total of nine units during 2007 and 2008, Staff
5 asserts that the Company should be allowed funding for
6 six installations per year in 2010 and in 2011 at a
7 cost of \$1.05 million each year. In projecting only six
8 installations during 2009 based on three installations
9 through July, Staff adjustment fails to recognize that
10 reliability work, including shunt reactor
11 installations, is done predominantly in the fall of
12 each calendar year. Staff's straight line projection
13 for reactor installations is thus incorrect. In
14 addition to the three installations in 2009 to date,
15 the Company has completed layouts and has issued for
16 construction nine additional jobs (all of which are
17 shown in Exhibit SIIP-1, p. 143), and the Company
18 projects completion of 12 shunt reactor installations
19 in 2009 at a cost of \$1.373 million. Using Staff's
20 method based on 2009 work, the allowance for 2010 and
21 2011 should reflect at least 12 installations per year
22 at an annual cost of \$1.373 million.

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1 Work Management System (SIIP, pp. 59-60) The Audit
2 Report issued by The Liberty Consulting Group in the
3 recently concluded management audit of Con Edison made
4 the following finding (p. XIII-60): "There is no overall
5 work management system in place to link work scope,
6 schedules, and cost. A system is needed to allow for
7 detailed project management of an individual and at the
8 same time allow for high level program management and
9 control. A work management system would also support
10 other important processes such as material accounting,
11 cost accounting and crew resource management". The
12 Audit report recommends (p. IIIX-63) that Con Edison
13 "Implement a work management system in Electric
14 Operations."
15 Many utilities are using work management systems and
16 processes that support best practices in the work
17 environment. These best practices include a focus on
18 optimized work, rather than reactive work or proactive
19 work. Optimizing work focuses on cost effectiveness
20 across the portfolio of available work. Technology, in
21 the form of systems and applications, is one tool that
22 aids identifying cost-effective work by providing high
23 quality data that can be used for decision making on a

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1 timely basis. A work management system or application
2 suite is required to meet these needs.

3 Staff asserts that the work management system "project
4 is not necessary at this time; and, extending the time
5 frame to complete this project would not hinder the
6 safety, performance, or reliability of the electric
7 system". In stark contrast to Staff's view, the Audit
8 Report states the following (XIII-63 and 64):

9 There is no current system in place that
10 integrates scope, cost and schedules for the work
11 packages. This makes project control and oversight
12 difficult. Due to this lack, considerable effort
13 is being expended to organize and direct the
14 normal construction work of the distribution
15 system. In addition to the difficulty of managing
16 this work, many opportunities for cost control are
17 not readily apparent and are opportunities missed.
18 ... With respect to cost benefit, we emphasize that
19 the current mode of operations contains hidden
20 costs that are very sizable.

21
22 On this point, the Audit report concludes: "In summary,
23 Liberty believes that the Company embraces the need for
24 a new system and is aggressively moving ahead, in
25 advance of this report, to make it a reality." Staff's
26 recommendation (p. 60) to "in effect, double the time
27 to complete the project" should be rejected.

28

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1 Q. Please comment on Staff's proposed global adjustment to
2 T&D expenditures.

3 A. The Company is currently developing its system and load
4 area peak load forecasts reflecting summer 2009 peak
5 loads and over the next few months will use these
6 forecasts to establish its 2010 T&D capital budget.
7 Similar to the approach that the Company used in Case
8 08-E-0539, the Company will provide the parties an
9 updated 2010 T&D capital budget projection in late
10 2009, along with the impact of that updated budget on
11 its revenue requirement in this proceeding.

12

13 Q. What is the next area of your rebuttal testimony?

14 A. Next we will address the cap on net T&D plant proposed
15 by Staff's Infrastructure Investment Panel and portions
16 of the testimony of Staff witnesses Nicola Jones
17 (Reliability Incentive Mechanism), and John Sennett
18 (Security).

19

20 Staff Infrastructure Investment Panel

21 Q. Does Staff propose a cap on net T&D plant?

22 A. Yes. Staff IIP (pp. 83-84) proposes that that Staff's
23 proposed T&D plant-in-service levels be the maximum

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1 limit on the amount of T&D plant used for ratemaking
2 purposes and if the Company's adds a lesser amount to
3 rate base during the rate year, the Company should
4 refund to ratepayers the associated incremental
5 carrying charges.

6
7 Q. What is the Company's position on this proposal?

8 A. This mechanism is in effect for the current rate year
9 per the Commission's 2009 Rate Order. As discussed in
10 the direct testimony of Company witness Rasmussen, the
11 Company accepts continuation of the mechanism during
12 the rate year in this proceeding, but the
13 reconciliation mechanism should be based on a
14 reasonable forecast of the Company's rate year T&D
15 capital expenditures.

16 Q. Any additional thoughts on this matter?

17 A. Staff has proposed adjustments totaling \$214.9 million
18 to the Company rate year capital T&D expenditures - a
19 16% reduction (Exhibit LAR-5). Staff has adjusted
20 programs and projects individually and then set a lower
21 aggregate spending cap citing the need for austerity.
22 While we have accepted many of Staff's adjustments, we
23 have demonstrated that many adjustments are without

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1 merit. Excessive adjustment to the Company's overall
2 requirement for T&D capital exacerbates the need to
3 reprioritize expenditures when unanticipated conditions
4 require capital investment beyond budgeted amounts, and
5 in that process funding for important programs may be
6 reduced to fund higher priority exigencies.
7 Unfortunately, in rate proceedings, Staff often cites
8 such reductions in historical spending as a lack of
9 commitment to a program and recommends further spending
10 reductions as slippage adjustments for those programs.
11 As a result, relatively "lower priority" important
12 programs are displaced year after year, with further
13 cuts recommended by Staff. As indicated above,
14 deferral of such programs will ultimately affect safe
15 and reliable service. Accordingly, the use of slippage
16 adjustments in combination with global adjustments must
17 provide an overall reasonable forecast of rate year T&D
18 expenses. The Commission tried to achieve this balance
19 in its 2008 Rate Order when it stated:
20 ...The basis for adjustment adopted here is not
21 simply one of slippage but rather a reasonable
22 restriction on overall spending, in order to
23 mitigate rate increases, without undue
24 disruption of the Company's construction
25 schedule. The purpose of the adjustment is to
26 reflect a realistic overall funding level, not

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1 to discourage the Company from undertaking any
2 particular project. (March 2008 Order, p. 91)
3

4 In short, the T&D expenditure reconciliation mechanism
5 must reasonably address the nature of the Company's
6 capital expenditure program on an aggregate basis, must
7 be premised upon a forecast that does not ignore the
8 inevitability of changed circumstances which the
9 Company must have the flexibility to address, and must
10 also consider investor interests in a fair and even-
11 handed manner.
12

13 Q. Have you reviewed the testimony of the Staff
14 Reliability Performance Mechanism Panel ("RPM Panel")
15 with respect to the Electric Service Reliability
16 Performance Mechanism ("RPM")?

17 A. Yes.
18

19 Q. Do you agree with Staff's recommendation on radial
20 CAIDI and radial SAIFI RPM targets?

21 A. No. For the radial CAIDI, the Company proposed a
22 target of 2.15 hours reflecting 10% above the last 10-
23 year average of the performance numbers. Staff applied
24 the same formula, but eliminated the performance during

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1 1999 and 2006 as outliers, and proposes a target of
2 1.97 hours. The Company agrees with Staff's conclusion
3 that, on a relative basis, 1999 and 2006 were generally
4 hot years. However, the performance mechanism applies
5 equally in relatively warmer and relatively cooler
6 years and expressly states that heat-related outages
7 are not excludible. Accordingly, the Company's
8 performance during warm years should not be excluded.
9 The effect of Staff's eliminating these two warm years
10 is to unfairly skew the targets tighter since the
11 longer duration performance is eliminated from the
12 calculation for targets, but the weather patterns will
13 still be experienced by the Company due to the natural
14 variability of the weather. Therefore, the Company
15 continues to support use of all ten years in
16 establishing the performance target. However, if
17 Staff's approach were to be used, it should be applied
18 fairly and uniformly by also excluding the two years
19 with the shortest duration performance - 2001 and 2003.
20 The two years experienced cooler and better weather in
21 general. Exclusion of these two years as well as the
22 two years excluded by Staff produces a radial CAIDI
23 target of 2.04 hours.

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1 With regard to radial SAIFI, the Company proposed no
2 change. Staff's proposed change from 0.530 (530
3 interruptions per 1,000 customers per year) to 0.470 is
4 a substantial tightening that lowers the standard by
5 over 53,000 outages per year. The five-year average
6 for New York State utilities other than Con Edison is
7 0.980. Con Edison's five-year average is 0.450. Con
8 Edison's overhead radial system performance is already
9 more than two times better than that or the rest of the
10 state.

11 At the same time, Staff proposes that the Company
12 reduce overhead system capital expenditures for
13 reliability programs, including Autoloop Reliability,
14 Okonite Cable Replacement, Overhead Sectionalizing
15 program, and C Truss Program, that Staff asserts are
16 "low priority." A tightening of reliability standards
17 is inconsistent with Staff's capital expenditure
18 proposals and pursuit of further austerity. Staff's
19 proposal to tighten the radial SAIFI target is
20 unwarranted and should be rejected.

21 If the Commission accepts Staff's position that the
22 radial SAIFI target should be calculated consistently
23 with the radial CAIDI target, then as we discussed

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1 above regarding the CAIDI target, the full ten-year
2 performance best captures the Company's performance in
3 warmer and cooler years and should be used to calculate
4 radial SAIFI. The target on that basis is 0.491. If
5 Staff's approach of excluding years is to be used, then
6 the two years of best interruption performance - 2000
7 and 2007 - should be excluded along with performance
8 during worst performing years - 2005 and 2006 - as
9 proposed by Staff. This calculation results in a
10 radial SAIFI of 0.495.

11 Staff's 0.470 is much too aggressive and is an abrupt
12 and substantial adjustment from the current target of
13 0.530. Looking at the Company's actual performance
14 over the last ten years (see Exhibit NJ-3, p. 6) the
15 Company exceeded 0.470 in four years and barely
16 achieved that level in two other years. The revised
17 target would penalize the Company in at least four of
18 ten years based on historical performance. Such a
19 tight standard is unwarranted.

20

21 Q. Does the Company agree with Staff's recommendation on
22 redefining a "network major outage" to be the

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1 interruption of 15% or more customers in any network
2 for a period of three hours or more?
3 A. No. Staff based its recommendation on 8 outages
4 identified by the Company that meet the existing
5 criteria of 10% threshold for 3 or more hours. This
6 basis does not address the disproportional nature of a
7 uniform 15% threshold that would penalize the Company
8 for an outage to as few as 2 customers for the smallest
9 network (Randall's Island network has 9 customers) or
10 as large as 21,685 customers for the largest network
11 (Jamaica network has 144,568 customers). Staff defines
12 a major outage mechanism to provide accountability for
13 large scale outages that are fully under the control of
14 the Company. Staff does not define the minimum number
15 of customer outages that it considers "major" and
16 rejects Company's proposal of 2,500 customers as a
17 minimum for major outage. A 2,500 network customer
18 outage would be a very low threshold in contrast to the
19 70,000 customer threshold for radial system major
20 outage. A 2,500 network customer outage would also be
21 a very low threshold considering that summer and winter
22 storms often interrupt many more customers on the
23 radial system.

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1 Staff argument that setting a threshold at 2,500 will
2 incentivize the Company to design smaller networks in
3 order to avoid the RPM ignores the multiple orders of
4 magnitude in investment required to redesign existing
5 networks (to reduce size). Moreover, Staff will have
6 ample opportunities to implement its proposal if and
7 when the Company redesigns existing networks to avoid
8 the RPM and there is no justification to penalize the
9 Company now.

10 This unduly punitive RPM exposes the Company to
11 extremely high revenue adjustments on a per customer
12 outage basis in the small networks. There are 10
13 networks where a 15% threshold at less than or equal to
14 500 customer outages will expose the Company to
15 punitive revenue adjustments on a per customer outage
16 basis.

17

18 Q. Does the Company agree with Staff's recommendation on
19 gradual increase in revenue adjustment based on the
20 outage duration?

21 A. We agree to the extent that Staff has recognized
22 proportionality in the application of the sanction.
23 However, during a major event both the extent of

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1 outages and the outage duration should be considered in
2 establishing a revenue adjustment. Staff's recognition
3 of only duration does not adequately address the scope
4 of the outage event.

5

6 Q. Does the Company agree with Staff's recommendation on
7 increasing the revenue adjustment from \$10 Million to
8 \$15 Million per event?

9 A. No. Staff provides no basis for the increase in the
10 maximum revenue adjustment from \$10 million to \$15
11 million per event for outage durations exceeding 12
12 hours. Staff does not provide any justification for
13 this arbitrary 50% increase in the revenue adjustment.
14 Indeed, Staff does not discuss either the purpose of
15 the major outage mechanism or how the prospect of a
16 revenue adjustment promotes that purpose. Staff has
17 not demonstrated that a \$15 million adjustment is more
18 likely to accomplish the purpose of the mechanism than
19 the current \$10 million adjustment.

20

21 Q. Has the Company analyzed the potential financial impact
22 of the MOPM?

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1 A. Yes. The Company reviewed network outages from 1998 to
2 2007 to determine the potential financial impact of the
3 MOPM for network major outages that exceeded the 15%
4 threshold. A total of 4 outages would have exceeded the
5 15% threshold for 3 or more hours. In total, the
6 Company would have paid \$45 Million over 10 years. In
7 one instance the Company would have paid \$5 million for
8 interrupting 58 customers for less than six hours, an
9 amount extremely punitive in the context of the outage
10 impact costs. In addition, large revenue adjustments
11 for such small, infrequent outages distort public
12 perception and appreciation for Company's unparalleled
13 reliability performance.

14

15 Q. Do you agree with Staff witness Sennett that the
16 Company's Bulk Power System (BPS) substations be at the
17 'top of the list' regarding security related upgrades?

18 A. Yes. The Company agrees that the BPS be given top
19 priority in substation security related upgrades to
20 conform to Corporate specifications.

21 Q. Do you concur with Mr. Sennett's technological upgrades
22 as detailed in his direct testimony beginning on page 3
23 line 3?

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1 A. While we appreciate Mr. Sennett's recommendations of
2 specific technological applications to further enhance
3 the security of our BPS it is not reasonable to assume
4 that we had ample opportunity to explore them in great
5 detail. We have taken them under advisement and will
6 evaluate them accordingly.

7

8 Productivity Adjustment

9 Q. What is the next area of your rebuttal testimony?

10 A. We will address the Staff Infrastructure Investment
11 Panel's and City witness Arnett's proposed 2 percent
12 productivity factor.

13

14 Q. What is the basis for the Staff Panel's proposal?

15 A. The Staff Panel asserts, without the benefit of any
16 analysis, that the increased investments in the
17 Company's infrastructure will result in fewer
18 unforeseen events, reduce the necessity to make costly
19 reactionary repairs, and therefore the Company should
20 be expected to become more productive in its core
21 business. Staff relies on the Commission's order in
22 the Company's last electric rate proceeding as its
23 basis for recommending that the Commission continues to

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1 apply the two percent productivity imputation
2 established in the 2009 Rate Order.

3

4 Q. What is the basis for Mr. Arnett's proposal?

5 A. Like Staff, Mr. Arnett's proposal is based upon the
6 Company's projected level of capital spending. Unlike
7 Staff, Mr. Arnett does make an effort to support his
8 assertion by presenting his review of the Company's
9 infrastructure investment programs. However, the
10 review made in this case is virtually identical to the
11 reviews he performed in the Company's two previous
12 electric rate cases in support of his three percent
13 productivity proposals, which have been routinely
14 rejected by the Commission. As was the case in the
15 last proceeding, Mr. Arnett, whose credentials indicate
16 no experience or expertise in these operational areas,
17 relied exclusively and apparently without any technical
18 assistance, on white papers submitted by the Company in
19 support of its projects and programs. Mr. Arnett made
20 no attempt whatsoever to explore or test the
21 conclusions he drew from these white papers through
22 either formal or informal discovery. The Company
23 demonstrated in the last case how and why Mr. Arnett

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1 drew erroneous conclusions from his exercise. Below we
2 explain why he has drawn similar erroneous conclusions
3 in this case.

4
5 Q. Please state generally why the Commission should not
6 adopt Staff's or Mr. Arnett's recommendation.

7 A. The Commission's action to establish a two percent
8 productivity imputation in the last case was clearly
9 driven by its desire to impose austerity reductions.

10 Specifically, the Commission stated (pp. 37-38):

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

24
25 The presiding officers found there to be no basis in
26 the record for increasing the one-percent productivity
27 imputation, and there was no basis in the record for
28 the Commission to reverse that evidenced-based
29 conclusion. The Company notes that it has a pending
30 request for rehearing of this determination made in the

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1 2009 Rate Order.

2 Moreover, the Commission itself recognized the absence
3 of an evidentiary basis for the two-percent imputation.

4 In addressing Mr. Arnett's analysis, the Commission
5 stated (2009 Rate Order, pp. 36-37):

6 The NYC Government Customers have identified
7 particular projects and programs where they think
8 productivity gains can be achieved, and there are
9 identifiable Company investment levels associated
10 with those projects and programs. Even conceding
11 that some savings might be achievable from those
12 projects, however, there is no way to extrapolate
13 the extent to which any savings that might arise
14 would fall within the typical 1% imputation or
15 might materially exceed that level --especially
16 approaching a 200% increase over that level. The
17 NYC Government Customers' witness merely
18 constructed a table showing each new Company
19 project or program and, if the associated Company
20 white paper mentioned any possibility of greater
21 reliability or efficiency, labeled that project or
22 program as a source of additional productivity,
23 but with no analysis of the amount of savings that
24 might be realized from any particular project or
25 program. (emphasis added)
26
27

28 Q. Please explain why a high level of investment in
29 infrastructure does not equate with a doubling of
30 expected productivity from such investments.

31 A. A simple way to view Company investments is to envision
32 the basic objectives of new investments, for example,
33 to replace or enhance existing facilities, to meet new
34 customer or regulatory requirements, or to achieve

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1 operational savings. These reflect primary purposes of
2 utility investments, and we agree investments can have
3 other impacts, so an investment to replace old
4 equipment can produce savings even though reliability
5 rather than cost reduction is the motivation for the
6 investment. However, an increase in investments in
7 infrastructure in and of itself provides no basis for
8 assuming that productivity savings will result, save
9 for the relatively few projects as to which a major
10 premise is achievement of operational savings, such as
11 would be the case with the AMI program discussed below.
12 In fact, many of the Company's new projects do not
13 result in productivity savings, and many will require
14 additional personnel to operate and maintain new
15 facilities, like substations.

16

17 Q. Please continue.

18 A. A substantial portion of the Company's investments are
19 to meet load growth. Expansion of the Company's
20 infrastructure to meet load growth will increase, not
21 decrease the Company's maintenance responsibilities
22 especially in the short term. For example, there will
23 be more equipment including network transformers,

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1 manholes, and service boxes which require inspection to
2 determine and complete necessary repairs.

3 The cost composition of increased capital spending is
4 also a factor that needs to be considered before one
5 makes the leap that increased capital spending leads to
6 productivity. For example, sharp increases in the
7 component parts of new capital equipment, such as
8 copper and steel, will lead to increased costs but not
9 to increased productivity. Similarly, another cause of
10 increases in capital spending has been a material
11 increase in capitalized pension costs as compared to a
12 much lower amount in previous years when the financial
13 markets were robust. Neither Staff nor Mr. Arnett
14 takes note of this fact.

15 In sum, Staff and Mr. Arnett have provided no basis for
16 assuming that the infrastructure program proposed in
17 this proceeding as compared to the level of
18 infrastructure investments during "normal times" (which
19 Staff has not defined) should result in a doubling of
20 unidentifiable and unquantifiable productivity.

21 In fact, if the one percent imputation historically
22 applied assumed an annual capital expenditure level of
23 approximately \$700 million in the context of a \$14

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1 billion rate base, or 5%, then there is no basis to
2 assume that spending an additional 5% of rate base
3 annually should produce twice the amount of
4 productivity. Such premise, which underlies the Staff
5 and NYC proposals, does not stand analysis. For
6 example, does that mean that Company's past
7 (approximately) \$700 million annual capital program
8 triggered the Company's one-percent annual savings? If
9 not, does it mean that a doubling of capital spending
10 that represents a small fraction of the utility rate
11 base should trigger a doubling of operations and
12 maintenance productivity extracted from the entire
13 utility system? It is fair to ask, why would that be
14 so? The question is particularly warranted when, as
15 noted, the Company's capital projects were not
16 undertaken principally for operational savings. For
17 example, it would be one thing if the Company were
18 implementing a large-scale AMI (advanced metering
19 infrastructure) program that envisioned system-wide
20 conversion to automatic meter reading. It is quite
21 another when the capital program is focused, as it is,
22 primarily on the electric grid itself and primarily on
23 service reliability.

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1

2 Q. Staff says the Company did not, in most circumstances,
3 identify or quantify potential savings associated with
4 its capital and O&M programs during the next few years.
5 Is that a fair comment?

6 A. Absolutely not. The Panel's initial testimony (pp. 19-
7 24) discusses productivity and process changes that
8 were already taken into consideration for this filing.
9 The IIP's initial testimony (pp. 25-30) also addresses
10 numerous projects and programs where costs have been
11 mitigated to reduce the level of requests in this
12 filing. Other Company witnesses performed similar
13 analyses. In fact, in discovery, the Company provided
14 additional detail as to the extent to which the
15 Company's rate request was reduced to reflect
16 productivity that the Company identified and
17 quantified. Staff ignores these savings for purposes
18 of its analysis while Mr. Arnett makes the
19 extraordinary assertion that productivity gains for
20 specific programs are meant to be incremental to the
21 one or two percent general productivity adjustment.

22

23 Q. Do you agree?

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1 A. We do not. Such a position is not credible. In fact,
2 the Commission stated in the 2009 Rate Order (p. 36):

3 The usual 1% productivity adjustment applies in
4 the absence of clear and convincing evidence that
5 potential productivity improvements have been
6 factored into a company's forecast of rate year
7 operations.
8

9 The Company presented those adjustments. Staff and Mr.
10 Arnett ignored them. Accordingly, even assuming the
11 Commission finds there to be a basis for a productivity
12 imputation in this case higher than one percent, it
13 cannot ignore the productivity already factored into
14 the Company's rate request.

15 In fact, in past Commission proceedings, Staff has
16 acknowledged that the productivity imputation is
17 warranted only where a utility does not otherwise
18 identify a reasonable level of productivity in its rate
19 filing. Yet Staff, like Mr. Arnett, seeks to capture
20 both in this case. Such an approach is particularly
21 surprising after the Company responded to criticism in
22 the last case regarding its failure to quantify
23 productivity savings in its rate filing and made
24 additional efforts to do so in this case.

25 While Staff and Mr. Arnett take the Company's proposed
26 one percent productivity adjustment to mitigate rates

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1 as a starting point in the discussion, there is no
2 basis for such a view.

3

4 Q. Did the Company identify other programs that could
5 produce unquantifiable savings in the rate year, as Mr.
6 Arnett asserts?

7 A. We acknowledge that possibility for some programs but
8 not in the magnitude that merits a productivity
9 adjustment in excess of one percent annually.

10

11 Q. Is there any basis for assuming a near-term material
12 increase in the prospect for productivity savings from
13 the Company's proposed O&M programs?

14 A. No, there is not any basis for assuming that the
15 Company's new O&M programs will result in a near-term
16 material increase in productivity. As explained by the
17 Company, many of its programs are designed to meet load
18 growth and reduce the risk to the public and employees
19 by increasing the levels of equipment testing,
20 inspections, and completing related repairs.

21

22 Q. Please comment on the conclusions drawn by Mr. Arnett
23 from his review of Company white papers.

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1 A. As was the case in the Company's previous electric
2 proceeding, Mr. Arnett drew erroneous conclusions from
3 his review. As an example, Mr. Arnett identified 20
4 substation projects and programs that purportedly
5 provide productivity enhancement opportunities. These
6 twenty projects and programs represent a total of
7 \$110.2 million. The Company reviewed the twenty
8 substation projects and programs that Mr. Arnett
9 identified as O&M productivity opportunities. The
10 "analysis" conducted by Mr. Arnett is flawed and vastly
11 overstates the potential for O&M productivity savings,
12 especially in the near term.

13

14 Q. Please explain.

15 A. Of the 20 projects and programs identified by Mr.
16 Arnett, nine provide essentially no opportunity for
17 near term O&M savings - the primary benefits of the
18 programs are realized through improved reliability or
19 through benefits achieved well outside of the rate
20 period. The remaining programs identified by Mr.
21 Arnett provide only a limited opportunity for near term
22 O&M expenditure reduction benefits, and cannot be said
23 to constitute project spending outside the "normal

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1 range" for which the one percent productivity
2 adjustment has historically be deemed adequate. These
3 9 projects and programs total \$71.2 million in capital
4 expenditures compared to the \$110.2 million referenced
5 by Mr. Arnett. Of the projects and programs that Mr.
6 Arnett identifies as having productivity opportunities
7 during the rate period, there are only a few instances,
8 if any, of potential minimal savings. A summary of
9 those programs cited and comments follows:

- 10 • Elmsford - Install new substation - The service
11 date for this project is 2011. Therefore,
12 there is no opportunity for productivity
13 savings associated with this project, if any,
14 until after 2011.
- 15 • Replace Obsolete Transformers - This program is
16 aimed at proactively avoiding failures through
17 targeted replacement of older transformers.
18 The primary benefit realized is improved
19 reliability and reduced capital expenditures
20 associated with replacing transformers upon
21 failure.
- 22 • Relay Modifications - The primary benefit of

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- 1 this program is improved reliability as a
2 result of upgraded relay protection system
3 designs, not reduction of ongoing O&M expenses.
- 4 • High Voltage Test Sets - The vast majority of
5 funding for this program is for new
6 distribution voltage level and high voltage AC
7 test sets which will actually add equipment
8 assets and maintenance requirements.
9 Approximately \$0.500 million of the \$5 million
10 capital program is allocated to high voltage DC
11 test set replacement, which would provide only
12 a limited opportunity to reduce O&M
13 expenditures.
 - 14 • Substation Automation Target Information System
15 - This program is primarily aimed at acquiring
16 more operational data on substation equipment
17 thereby providing an O&M reduction opportunity
18 in the long term by facilitating a transition
19 to condition based maintenance, but will not
20 provide O&M savings in the near term.
 - 21 • SOCCS RTU Replacement - This program is driven
22 by installation of the new Energy Management

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- 1 System. The equipment replacement will provide
2 for more functionality and thereby, increasing
3 operational reliability and does not materially
4 reduce ongoing maintenance (O&M expenses)
5 costs.
- 6 • Corona - Breaker Addition (6S and 8X) - As this
7 program will add 2 pieces of equipment to our
8 system that will require maintenance, the net
9 effect would be to increase costs, not reduce
10 them.
- 11 • El3th St. Alarm Panel Replacement and Control
12 Systems - This project is not planned to start
13 until 2011 and be completed until 2012. As
14 such, it will not provide any potential for O&M
15 savings until 2013 at the earliest.
- 16 • Circuit Switcher Replacement Program - As noted
17 in the Company's white paper regarding this
18 program, its goal is the replacement of a
19 number of circuit switchers that are no longer
20 supported with spare parts or technical
21 expertise by the original equipment
22 manufacturer. The primary reason for this is

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1 to avoid long term outages in the event of an
2 equipment failure, thereby increasing system
3 reliability. While this program may offset
4 future increases in O&M costs, it will not
5 materially reduce ongoing maintenance (O&M
6 expenses) costs.

7
8 Q. Are there other reasons for rejecting the proposed two-
9 percent productivity imputations?

10 A. Yes. Staff and the City claim that, going forward, the
11 Company can expect to build on its record of success in
12 achieving productivity, but there are countervailing
13 factors that tend to work against continued progress
14 and make continued achievement of one percent
15 productivity very challenging. For example, the growth
16 in and growing complexity of NYC's economy. The City's
17 population has increased, the number of people working
18 in the City has increased, and the number of visitors
19 to the City has increased. This is good news for the
20 City itself, but it heightens the complexity of utility
21 operations. Construction activity increases, street
22 activity increases, traffic increases, underground
23 activity increases and underground congestion

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1 increases. These factors clearly present increased
2 challenges that decrease, rather than increase, the
3 prospects for productivity even at the historical one
4 percent level. In addition, there has been increased
5 regulation in various areas of the Company's business
6 (e.g., stray voltage) that establish increased
7 reporting requirements and additional operating
8 procedures that further tax the time employees would
9 otherwise have to achieve productivity savings. In
10 addition to increased regulation, we continue to invest
11 in our employees, with training and emphasis on
12 employee and public safety and environmental
13 excellence; we strongly believe the extensive training
14 we give to our employees is worthwhile and appropriate,
15 but the training and the adherence to procedure can
16 affect traditional productivity measures.

17

18 Q. Please continue.

19 A. Our workforce is less experienced and training
20 requirements again come into the productivity
21 measurement. For example, a new hire to our field
22 (physical) work force (generally someone who recently
23 graduated high school) will require on average 3 to 6

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1 years of experience and training before reaching one of
2 the lead titles.

3

4 Q. Mr. Arnett seeks to buttress his proposal by first
5 acknowledging that there are investments that will not
6 contribute to productivity during the rate year because
7 they will not go into service by the end of the rate
8 year, but then asserting that there are projects that
9 will go into service during the linking period to which
10 productivity savings should be attributed. Do you
11 agree?

12 A. No. First, there is no dispute that efficiencies
13 achieved by projects that went into service as recently
14 as 2007 and 2008 are captured in the test year data.
15 As for the linking period, as indicated above, for
16 various Company programs initiated pursuant to prior
17 rate plans, the Company's forecasts for the rate year
18 already reflect efficiencies from these past
19 investments.

20 In addition, the Company's calculation of a one percent
21 productivity factor specifically takes into
22 consideration the linking period. That is, the
23 adjustment to labor escalation with and without the

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1 "one percent productivity imputation" is an approximate
2 2.6 percent difference. Accordingly the Staff's and
3 City's two percent productivity proposals essentially
4 amount to imputations for unidentifiable and
5 unquantifiable productivity of 5.2 percent of the
6 Company's labor costs.

7
8 Q. Do you have additional comments?

9 A. Yes. We do not here address the Staff proposal that the
10 Company defer savings resulting from the implementation
11 of the recommendations of the Liberty consulting audit,
12 although implementation of that Staff recommendation is
13 clearly a double-count to the Staff annual productivity
14 imputation. The Company's Policy Panel will further
15 address Staff's proposal.

16

17 Q. What is the next area of your rebuttal testimony?

18 A. We will address recommendations of the Consumer
19 Protection Board's ("CPB") witness Helmuth Schultz
20 ("Schultz").

21

22 Substation Operations' Adjustments

23 Q. Do you agree with Mr. Schultz's testimony and

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- 1 adjustments concerning Substation Operations O&M
2 program for the staffing new of facilities?
- 3 A. No, we do not. Mr. Schultz adjusts Con Edison's \$2.128
4 million program change for Substation Operations by
5 \$837,000. He claims that since he removed the overtime
6 (\$699,000) associated with substation operations as
7 part of his overall overtime adjustment, he believes
8 that the non-labor costs of \$438,000 should be reduced
9 by one-third, or \$138,000. This would allow
10 substations a program change of \$300,000 for non-labor
11 and some unspecified amount for labor associated with
12 nine requested positions.
- 13 Q. Does Mr. Schultz give any more detail or justification
14 for his adjustment?
- 15 A. No.
- 16 Q. Please explain the rationale for the labor portion
17 (\$990,000) of the Substation Operations program change.
- 18 A. The labor portion (\$990,000) of the Substation
19 Operations O&M request of \$2.128 million is for
20 Staffing at substation facilities that have either been
21 newly completed or will be in-service early in the rate
22 year. These facilities are Astor (went into service in
23 March 2009), Academy (scheduled to be in service in

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1 early 2010) and Newtown (scheduled to be in service in
2 early 2010) and will require nine employees in total.
3 The program change is the amount required to properly
4 operate these facilities in a safe, reliable and
5 environmentally sound manner.
6 Substation personal are required to perform a myriad of
7 daily and monthly work functions. A sample of these
8 work functions is as follows:
9 Tranmission and Distribution switching, station
10 inspections, monthly compliance items, seasonal
11 preparation of equipment (infrared and various circuit
12 breaker, transformer and various other equipment
13 inspections), scheduled and corrective maintenance of
14 facilities, relay systems, transformers, circuit
15 breakers, dielectric facilities, high voltage test
16 sets. In addition, substation personnel provide
17 enhanced station security (when staffed), and are the
18 Company first responders in the case of environmental,
19 security and weather related incidents.
20 Since these are new facilities, new personnel are
21 required to staff the substations. More important,
22 this request was allowed in the last electric rate
23 case, and it should be noted that the GUV Operators

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1 were hired in the first quarter of 2009. Mr. Schultz's
2 approach eliminates these previously approved slots
3 with no basis, analysis or rationale to support it.

4
5 Q. Please discuss the overtime portion of Mr. Schultz's
6 adjustment.

7 A. The program change of \$699,000 for overtime was based
8 on a calculation of the total hours required to operate
9 these facilities on an annual basis and the staffing
10 levels projected for each station. Operator coverage
11 and mechanic staffing requirements are reviewed and
12 determined on an individual station basis and are two
13 separate and distinct requirements. As such, these
14 stations at times, require overtime to meet staffing
15 levels. Mr. Schultz's elimination of the approximately
16 6 EOT's, or 10,980 hours, of station coverage would not
17 allow the department to provide adequate emergency
18 coverage required to address emergent system conditions
19 at these three new stations. The elimination of
20 overtime coverage would necessitate a corresponding
21 increase in Human Resources to properly operate these
22 stations. On overtime, substation personnel provide
23 operational and maintenance support for emergency

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1 situations such as: snow, thunder and heat storms,
2 hurricanes, high wind and rain, station security,
3 equipment repairs and emergency restoration of critical
4 transmission and distribution equipment

5 Q. Please explain why Mr. Schultz's adjustment for non-
6 labor is incorrect.

7 A. The program change of \$438,000 for non-labor or Account
8 Payable costs for the three new facilities was based on
9 multi-year analysis of the average costs required to
10 properly support the material requirements of in-
11 service facilities on an annual basis (\$150,000 each).
12 Mr. Schultz's elimination of \$138,000 of Station
13 Supplies and Expenses would not allow the department to
14 adequately meet the level of required material
15 component and vendor support to address the annual
16 station needs.

17 Q. Is Mr. Shultz's assumption that a decrease in overtime
18 equates to a decrease in the need for supplies correct?

19 A. No. Mr. Schultz erroneously draws a correlation
20 between reducing overtime hours required to meet
21 emergent system needs and the elimination of material
22 and vendor support required to run a substation on a
23 day-to-day basis. For example, the hours required to

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1 staff stations for storm emergencies have nothing to do
2 with materials required for scheduled and non-scheduled
3 work functions related to facilities betterment,
4 transformers, circuit breakers and other station
5 equipment. Mr. Schultz's adjustments fail to consider
6 the needs for these new substations.

7 Q. Is there anything the Panel would like to add?

8 A. Yes. These negative cost adjustments are shortsighted,
9 and fail to consider the basic and proper levels of
10 operational needs and customer impact, especially when
11 one considers that the department is already absorbing
12 the anticipated future maintenance labor costs of
13 \$440,000 annually for these new facilities.

14 System and Transmission Operation Adjustments

15 Q. Turning to Mr. Schultz's next set of adjustments, do
16 you agree with the adjustment made for System and
17 Transmission Operations?

18 A. No, we do not.

19 Q. What adjustments does Mr. Schultz make to System and
20 Transmission Operations programs?

21 A. Mr. Schultz makes \$2.160 million worth of adjustments
22 to these projects. He reduces the requested allowance
23 for the Queensboro Bridge project by \$500,000; the

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1 Furnace Brook Dam project by \$200,000; Manhole
2 Inspections by \$250,000; Coating Refurbishment by
3 \$700,000; Bird Discouragers by \$270,000; and Orange and
4 Rockland Line Maintenance by \$240,000. Mr. Schultz
5 comments on Tower Painting but makes no adjustment for
6 the cost of this program. Each adjustment is
7 separately detailed and addressed below.

8 Q. What is the basis of Mr. Schultz's adjustment for the
9 Queensboro Bridge-Pipe Inspection/Refurbishment
10 program?

11 A. Mr. Schultz would disallow this program based on his
12 allegation that the Company did not provide supporting
13 documentation in the form of analysis or other
14 additional support to show what was used to develop the
15 estimate for the project as requested in CPB15-159.

16 Q. What did the Company provide to support the costs for
17 this program?

18 A. In response to CPB15-159, the Company provided an order
19 of magnitude estimate which provides elements of
20 expense details and cost break downs for repair of
21 facilities. As noted in Exhibit __ (IIP-8, p. 10),
22 this is a new program and historical data is not
23 available. The program is currently in the planning

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1 and development process and the Company provided the
2 best available information for this project. The
3 assessment of our equipment is currently ongoing, and
4 several areas along the feeder route require
5 maintenance work. A most recent inspection performed
6 has identified defects on the pipes which must be
7 addressed and this also reconfirms the justification
8 and need for this program.

9 Q. Please explain the need for and importance of this
10 program.

11 A. Mr. Schultz has failed to consider the age of the
12 feeders and the reliability consequences of not
13 addressing the nitrogen gas leaks on the feeders
14 running over this bridge. The Company's Exhibit ____
15 (IIP-8, p0. 10-12), explained that the potential
16 failure of the feeders due to the inability to maintain
17 nitrogen gas pressure may cause a system contingency,
18 which could result in the loss of customers due to load
19 shedding or voltage reduction of the affected networks
20 in mid-town Manhattan. If left unrepaired, thin wall
21 areas in locations where corrosion continues to occur,
22 will degrade to a point where the leak rate cannot be
23 maintained by the gas pressurization source, thereby

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1 jeopardizing the reliability of the feeders. If the
2 bridge feeders should fail because of failure to
3 maintain nitrogen pressure, permanent repairs and
4 restoration efforts to return the feeder to service
5 will be extensive.

6 Q. Please turn to the Furnace Brook Dam project (p. 36)
7 and explain Mr. Schultz's recommended adjustment.

8 A. Mr. Schultz claims that the Company failed to provide
9 the actual cost estimate for the Furnace Brook Lake Dam
10 maintenance program as was requested in CPB-150.
11 Rather, the Company listed the different cost types and
12 respective costs that total to the \$2 million. In
13 addition, the Company's response indicated that a
14 revised estimate provided a \$1.8 million cost. He
15 claims that, at a minimum, the cost request should be
16 reduced \$200,000. But he complains that the Company's
17 response consisted of only a cost summary.

18 Q. Do you agree with Mr. Schultz's adjustment?

19 A. Since the Company provided a revised estimate of \$1.8
20 million, we would agree to that adjustment. However,
21 with respect to Mr. Schultz's complaint, the Company
22 provided the then-available documentation to support
23 the cost estimate. Additional information has become

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1 available and will be provided in response to Mr.
2 Schultz's data request CPB 188.

3 Q. What is suggested regarding Manhole Inspections on pp.
4 36-37 of Mr. Schultz's testimony?

5 A. Mr. Schultz questions the cost increase for manhole
6 inspections from \$789 per inspection, prior to 2008, to
7 \$1,476 per inspection in 2008; claims that the
8 Company's filing are inconsistent in that Exhibit ____
9 (IIP-5); indicates that we plan to spend \$950,000, but
10 the Company's response to CPB-151 only includes
11 \$700,000 in expenditures due to the fact that this
12 program was reduced as a result of austerity; and notes
13 his concern that through June 2009, the Company
14 forecasted \$448,000 and had only expended \$333,000.
15 Mr. Schultz claims that because the Company "found a
16 need" to reduce the 2009 forecast and because as of
17 June 2009, the Company's expenditures on this program
18 were below budget, he adjusts the program by \$250,000
19 to bring the program to its 2008 expenditure level of
20 \$700,000.

21 Q. Do you agree with this adjustment?

22 A. No.

23 Q. Please explain why Mr. Schultz's per manhole cost

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1 argument is incorrect.

2 A. Mr. Schultz is correct when he points out that the cost
3 per manhole inspection increased to \$1,476 per
4 inspection in 2008. However, he fails to realize that
5 the increased cost in 2008 is attributable to the fact
6 that during 2008, the Company was performing an
7 enhanced manhole inspection that was requested and
8 allowed as part of Case 07-E-0523. The increase in the
9 unit cost is based on the Company performing more
10 comprehensive inspections on underground transmission
11 feeders. The comprehensive work beyond a standard
12 visual inspection includes the removal of all tape
13 coating and mastic on feeder pipes performing a visual
14 inspection and a wall thickness check on corrosion
15 areas between the reducer and the manhole walls. A
16 review of the dielectric fluid leak records indicates
17 that the largest number of corrosion leaks occur in
18 this area. The cause of these leaks is due to
19 atmospheric corrosion, a process that cannot be
20 prevented by cathodic protection.

21 Q. How do you address Mr. Schultz's comments about the
22 decrease in the 2009 expenditures?

23 A. The Company stated in response to CPB-151, this program

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- 1 was deferred as part of the Company's May 26, 2009
2 austerity filing, which reduced the level of
3 expenditures associated with manhole inspections in
4 2009 by approximately \$250,000. The 2009 budget is now
5 approximately \$700,000. We would note that the
6 Company's austerity filing discussed in the
7 Supplemental Testimony of Edward Rasmussen, as the
8 austerity reductions were not available at the time the
9 initial filing was made.
- 10 Q. Does the spending to date as of June reflect a linear
11 extrapolation of the Company's 2009 expenditures?
- 12 A. No. To begin, we would note that manhole inspections
13 are normally planned to be performed during the summer
14 period as work load of the department dictates and the
15 work schedule is adjusted to suit system and
16 operational needs of the department. As of July 2009,
17 66% of the total number of mandatory manhole
18 inspections for the year been completed and the company
19 anticipates completing the remaining balance of
20 inspections within the approved spending level. In
21 fact, as of August 2009 Transmission Operations has
22 spent \$479,000 on this program.
- 23 Q. Is Mr. Schultz's adjustment for manhole inspections

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1 appropriate?

2 A. As we have explained, it is not. The Company is
3 undertaking enhanced inspections, the austerity
4 adjustment is properly reflected and the filing is
5 consistent and the inspection work is being undertaken.
6 As such, Mr. Schultz's reasoning for his \$250,000
7 adjustment does not withstand scrutiny.

8 Q. Turning now to Mr. Schultz's \$700,000 adjustment for
9 coating refurbishment, what was the basis of this
10 adjustment?

11 A. Mr. Schultz notes that the Company is requesting \$1.5
12 million in the rate year, which is an increase of
13 \$1.338 million over the test year expenditures of
14 \$162,000 and that the \$1.5 million amount is based on a
15 three year average expenditure of \$1.4 million in the
16 years 2005-2007. Mr. Schultz claims that the \$1.4
17 million average amount includes approximately \$600,000
18 of expenditures for Public Improvement ("PI") coating
19 refurbishment work. Since the PI and coating
20 refurbishment programs are two separate programs, he
21 states that it is not obvious why the costs for the PI
22 program should be included in the coating refurbishment
23 program. As a result, he calculates a three-year

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1 average (2005-2007) of coating refurbishment costs
2 without the PI expenditures of approximately \$800,000.
3 He removes 2008 from the average, claiming those
4 expenditures were abnormally low. Based on this, he
5 proposes a \$700,000 adjustment. He claims that there
6 is further support for this adjustment based on the
7 Company's levels of spending through June 2009, since
8 only \$15,000 was spent at that point in time.
9 To address Mr. Schultz's concern on year-to-date
10 spending of \$15,000, it should be noted that this
11 coating refurbishment type work is typically performed
12 after the summer load period (May - September) to
13 preclude any risk of jeopardizing the reliability of
14 the transmission system during this period. Mr.
15 Schultz's comments fail to address the fact that the
16 Company significantly reduced the expenditures for this
17 program in 2009 under its austerity plan. The Company
18 expects to spend \$875,000 as a result of its austerity
19 adjustments. The Company is currently competitively
20 bidding a scope of work for pipe refurbishment and
21 expects to make an award to the successful vendor
22 shortly.
23 Q. Please continue.

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1 A. While Mr. Schultz has proposed reducing coating
2 refurbishment spending from \$1.5 million to \$700,000,
3 he failed to take into consideration the age of the
4 underground transmission system and its infrastructure.
5 The average age of the high-pressure pipe type system
6 is over 40 years old with the oldest systems over 60
7 years old. While the Company believes, and cable
8 testing by leading research groups such as EPRI
9 indicates, that high pressure pipe type cable systems,
10 when operated within their design parameters and
11 limitations can experience a long cable life well
12 beyond 40 years, this potential long life cannot be
13 achieved unless the steel pipes which encase and
14 protect these cables are in equal or better condition.
15 One of the main purposes of the coating refurbishment
16 program is to address localized coating problems before
17 allowing the corrosion to advance to a point where a
18 leak occurs and subsequently releases dielectric fluid
19 into the environment. Reducing funding for this
20 program prevents the Company from proactively
21 addressing corrosion issues before the leaks occur.
22 Leaks impact the environment and could potentially
23 impact system reliability if the leak is severe enough

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1 to force the feeder out of service.

2 The inclusion of the PI work with the Coating
3 Refurbishment Program in Exhibit ____ (IIP-4, p. 105) was
4 intended to highlight the amount of pipe refurbishment
5 that was performed by the Company regardless of which
6 department within the Company is performing the actual
7 work. Whether PI performs the work or S&TO bids out
8 the coating refurbishment work to a contractor, the
9 refurbishing of pipe still needs to be done

10
11 Using Mr. Schultz's adjustment would not allow the
12 Company the proper level of rate relief for this
13 program. \$1.5 million for the program is the correct
14 level of expenditures based on our projection to
15 refurbish 1,000 trench feet per year at a unit cost of
16 \$1,500 per trench. This is consistent with actual
17 amount of refurbishment performed in 2006 and 2007 and
18 our plans to address specific targeted areas on feeders
19 M51/M52 and 18001/18002 over the next three years.

20 The amount of coating refurbished is driven by the
21 total dollars allocated to the program and not by a
22 footage target, so if the unit cost is less than
23 expected, we would refurbish more linear footage of

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1 coating and if higher than expected, less coating would
2 be refurbished. Coating refurbishment costs are
3 contingent upon many variables which include the degree
4 of corrosion uncovered, condition of original coating,
5 quantity of pipes in the trench to refurbish,
6 environmental remediation costs and community impact.
7 Given the current age of the transmission system, and
8 no cost effective means for complete system
9 replacement, one alternative to ensure the continued
10 reliability is to address localized pipe corrosion
11 issues identified under the coating refurbishment
12 program.

13 Q. What adjustments does Mr. Schultz make to the Company's
14 bird discourager program?

15 A. Mr. Schultz states that the Company has received rate
16 relief for this program but as of 2008, "no money had
17 been expended. Ratepayers should not be paying for a
18 program before it is operational." He agrees that the
19 program has merit but suggests that \$270,000 be
20 disallowed until it can be established that costs are
21 being incurred.

22 Q. Do you agree with this adjustment?

23 A. No. Engineering has received the final report for the

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1 bird discouragers and will initiate detailed structural
2 analysis in 2010. Installation of the bird
3 discouragers is expected in the third and fourth
4 quarters of 2010. During 2009, feeder trip-outs have
5 occurred on the 345kV overhead system due to bird
6 activity. Consequently, eliminating funding in this
7 program in 2010 threatens system reliability. This
8 program was reduced by \$200,000 in 2009 as part of the
9 austerity plan and just under \$40,000 has been spent as
10 of September 2009. Although this project has
11 experienced delays due to the completion of the
12 specialized analytical ice and wind study, installation
13 will commence in 2010. Previously approved funding for
14 this program was utilized to offset the additional
15 costs associated with investigating feeder trip outs
16 from bird activities.

17 Q. Please address Mr. Schultz's adjustment for the
18 maintenance of Orange and Rockland lines.

19 A. Mr. Schultz recommends a \$240,000 reduction to this
20 program for several reasons. First, he notes that this
21 a nearly 80 percent increase over the amount expended
22 in 2008, which is driven by costs associated with
23 repairs, trimming, crewing and inflation. Second, he

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1 claims that as of June, the actual expense was below
2 the 2009 year-to-date budget set at \$525,000. Third, he
3 opines that the significant increase in tree trimming
4 contractor rate per mile is excessive. Finally, he
5 claims that the Company provided purchase orders but
6 not the bid documents. He alleges (p. 41) that
7 "[c]osts included in purchase orders cannot be verified
8 without the actual bid document. The purchase order
9 for tree trimming was based on an email that was not
10 included." Based on these arguments, he suggests a
11 \$240,000 reduction, comprised of \$125,000 for tree-
12 trimming and \$115,000 for crew and contractor costs.

13 Q. Do you agree with this adjustment?

14 A. Not at all. As to Mr. Schultz's contention that there
15 is nearly an 80 percent increase in this category of
16 costs, the tree trimming cost increase associated with
17 this program is a direct result of a change in the
18 vegetation management scope of work from previous
19 contracts. The increase in scope is due, in part, to
20 the fact that major tree removals along the CECONY
21 owned transmission lines are required during 2010 to
22 ensure reliability and compliance with NERC and PSC
23 vegetation management standards. The PSC Order

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1 mandates that utilities remove all incompatible
2 vegetation from the full width of the right of way
3 (ROW) instead of clearing the vegetation to a specific
4 measurement from the wires as was previously carried
5 out. This regulation change resulted in a
6 significantly increased tree removal scope which, in
7 turn, yielded a major contractor cost increase.

8 Q. Please continue.

9 A. Regarding Mr. Schultz's contention that the actual
10 expenses under these programs as of June 30, 2009 were
11 \$455,307 as compared to the year-to-date June 2009
12 budget of \$258,767, the \$525,000 referenced by Mr.
13 Schultz is actually the year-end budget, not the year
14 to date budget as Mr. Schultz claims. As of August, we
15 have expended \$576,050 versus a budget of \$350,000.
16 The Company is on track to exceed the amount budgeted
17 for this program.

18 Q. Please address Mr. Schultz's contention that the
19 Company provided only purchase orders and not bid
20 documents as well as a missing email.

21 A. Mr. Schultz is requesting documents that have no
22 relevance to the matter at hand. The Company has
23 explained that the increase in the costs is due to the

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1 increase in the scope of the work. Having the bid
2 packages to review the purchase orders is a level of
3 detail not required. Mr. Schultz is seemingly looking
4 to audit the Company, as opposed to making adjustments
5 on the merits of the program. The Company is providing
6 additional information in response to CPB 188 regarding
7 this program.

8 Q. Do you have any final comments regarding this program?

9 A. Yes. The \$125,000 reduction for tree trimming, which
10 is based on Mr. Schultz's calculation of allowing a 25
11 percent increase to 2008 costs, does not reflect the
12 Company's actual costs for performing this work. This
13 adjustment is not justified since different
14 transmission rights of way are treated during each rate
15 year and are different in nature. Each right-of-way
16 possesses unique characteristics such as terrain,
17 access issues, and most importantly, volume of large
18 incompatible trees that need to be removed. In 2008,
19 the 345kV lines between Ladentown and West Haverstraw
20 were completed as well as the 500kV line between Ramapo
21 and New Jersey. The total length of the feeders
22 completed in 2008 was approximately 11 miles whereas
23 the work scheduled in the 2010 rate year is for 36

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1 miles. As part of the Company's PSC approved
2 Vegetation Management Plan, each transmission line is
3 completed on a three-year cycle and mileage varies year
4 to year which is why the funding request changes. The
5 reduction of \$115,000 from \$240,000 for Con Edison crew
6 and contractor costs will affect the Company's ability
7 to maintain compliance with Federal Aviation Authority
8 requirements for keeping warning lights functional on
9 the East Hudson River Tower. Due to the height of this
10 transmission tower (approximately 500 feet), aircraft
11 warning lights must be installed and must be
12 operational to warn small aircraft that power lines
13 exist in the area. Six additional new strobe light
14 units and replacement parts are required to ensure
15 tower lights remain functional and prevent an aircraft
16 from damaging our tower and transmission lines crossing
17 the Hudson River. The Company was requesting \$115,000
18 for crews and contractors to perform this function and
19 this adjustment would prevent the necessary aviation
20 light repairs and upgrades from being made in a timely
21 fashion.

22 Q. Did Mr. Schultz make any adjustments to the Company's
23 Tower Painting program?

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1 A. No. He claims that the Company did not provide
2 estimates to justify cost of \$2,500 per tower, only
3 purchase orders, but he opines that the costs are
4 reasonable based on historical costs. As such, the
5 Company will not address this issue since no adjustment
6 was made but should Mr. Schultz attempt to make such an
7 adjustment in the future, we will respond to his
8 assertions at that time.

9 Electric Operations Adjustments

10 Q. Does Mr. Schultz make any adjustments to Electric
11 Operations programs?

12 A. Yes. He makes five adjustments - he reduces the rear
13 lot pole elimination program by \$1.449 million; he
14 removes \$445,000 from the danger tree program; he
15 removes \$2.826 million in labor from the five year
16 overhead inspection program; he reduces the mobile
17 stray voltage program by \$3.354M; and he adjusts the
18 electric distribution equipment repair and
19 reconditioning program by \$359,000. He also discusses
20 the engineering and services and line clearance
21 programs but makes no adjustment for them. Each item
22 will be addressed below.

23 Q. What points did Mr. Schultz state about the overhead

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1 conductor clearance programs?

2 A. As to the overhead clearance program, Mr. Schultz
3 states that he requested supporting documentation
4 (specifically bids and Company analysis) for this
5 program and the Company did not provide any
6 documentation and indicated that the expense is 10
7 percent of the capital costs, based on historical
8 levels. He alleges that the Company is missing
9 documentation and the historical calculation that would
10 substantiate the 10 percent split conclusion. He then
11 claims that the calculation of the amounts for this
12 program based on 10 percent is incorrect.

13 Q. Do you agree with Mr. Schultz's assertions regarding
14 the overhead conductor clearance program?

15 A. No. Con Edison is requesting additional funding for a
16 new project with a focus on providing minimum
17 clearances from overhead electrical facilities as
18 described in the National Electric Safety Code. These
19 clearances are required for the safety of the public
20 and for the protection of our distribution system. The
21 program is slated to begin in January of 2010 and seven
22 field locations have been fully evaluated at this
23 point. Members of both Overhead Construction and

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1 Engineering reviewed these locations in detail.
2 Electrical Layouts and their associated cost estimates
3 were developed and copies of these jobs have been
4 forwarded as requested. As indicated, since this is a
5 new program, the Company used an estimate of 10% of the
6 entire capital costs to determine the MAC portion. The
7 maintenance portion (MAC) of these projects include all
8 work activities associated with the transfer or
9 relocation of existing Con Edison facilities from one
10 pole to another and switching work, to de-energize and
11 re-energize the feeder. The capital portion includes
12 work activities such as pole installations, cable
13 installations, and conduit work. The 10% does not
14 represent a percentage from the capital labor, as
15 indicated by Mr. Schultz; it is an estimate cost for
16 the typical O&M work based on the total capital cost.
17 Based on historical MAC for similar programs, the 10%
18 estimate was used.

19 Q. What comments does Mr. Schultz make about the rear lot
20 pole elimination program?

21 A. As to the rear lot pole elimination program, Mr.
22 Schultz questions why the expense in the rate year
23 should increase so significantly.

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1 Q. Do you agree with Mr. Schultz's comments regarding the
2 rear lot pole elimination program?

3 A. No. In 2009, due to austerity and the O&M expenditures
4 associated with winter snow activity and the burnouts
5 in the secondary system, further work on the O&M
6 portion of these projects was deferred to 2010. As a
7 result of the work pending start in 2010, the company
8 anticipates to spend at a 1 to 1 rate for each O&M
9 dollar to each capital dollar spent.

10 Q. Mr. Schultz also states that spending in 2008 was well
11 below budget. Please comment.

12 A. 2008 was below budget but much of the under expenditure
13 was a result of coordination issues with customers,
14 which we do not expect will recur in the Rate Year.
15 Rear-lot pole elimination is a relatively new program
16 created as a result of customer interference with
17 distribution poles and lines that previously existed in
18 the rear-lots of customer properties. For example,
19 over the years additional homes have been built in the
20 access lanes that were previously used to bring in the
21 distribution equipment making it impossible to bring in
22 line trucks and heavy equipment to support timely and
23 efficient maintenance and restoration. Because there

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1 are a number of situations where a line has failed and
2 replacement is not possible due to customer
3 interference, the Company created the rear-lot pole
4 program to replace these distribution facilities.
5 While the company had specific projects and
6 distribution lines and both capital and O&M funds
7 available, coordination with customers and obtaining
8 their permissions has delayed this program. The
9 company has spent those budgeted capital funds
10 associated with installing new underground distribution
11 facilities on the street sides of the affected customer
12 properties.
13 For 2010, the Company has a number projects that are
14 all ready to start. Based upon these specific
15 projects, we project that the Company will have no
16 difficulty spending and completing the budgeted work.
17 Q. On page 44, Mr. Schultz states that the Company may
18 choose to leave the old poles in place. Please comment
19 on his concern.
20 A. Mr. Schultz is not clear on the reason why in certain
21 cases these poles are left in place. Once the Company
22 completes a rear-lot pole project, the new distribution
23 lines that are installed do not require the old poles.

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1 The poles may remain in place because telephone and/or
2 cable tv lines remain active on them. There are no
3 active company lines on any of these poles once a
4 project is completed. Ownership is then transferred to
5 the telephone company if it does not have a plan to
6 reroute its lines.

7 Q. Have you reviewed the testimony of CPB witness Schultz
8 on the Mobile Stray Voltage Testing Program?

9 A. Yes. We have reviewed the testimony and have a few
10 overall comments on his suggested reduction of \$3.354
11 million, which is based on the average monthly
12 inspection rate provided by the Company in purchase
13 orders for the program, increased by five percent for
14 escalation. He states that he used the difference
15 between his estimated cost for testing and the
16 Company's estimate for testing and applied the
17 percentage difference to the total cost of the program
18 requested. Mr. Schultz claims that the Company is
19 requesting a large increase for this program (64%) for
20 a nearly 8,000 mile increase in scans, and opines (p.
21 50) that "[e]ven if there were an increase in miles it
22 is not conceivable that the cost would increase at a
23 significantly greater rate than the increase in miles."

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1 He also claims that as a greater number of scans are
2 performed, fewer stray voltage conditions should be
3 found and therefore, there should be a decline in the
4 cost per scan and/or per mile. He claims that the cost
5 for testing exceeds the purchase order amount and that
6 the Company has not completed 12 scans in any one year.

7 Q. Does the Company disagree with Mr. Schultz's statements
8 about the Mobile Stray Voltage Testing program?

9 A. Yes. First, on page 50, lines 10 - 12, Mr. Schultz
10 incorrectly claims that the Company has been allowed
11 costs based on the assumption that 12 scans were to be
12 performed but that the Company only performed 10.6
13 scans in 2008. In the Commission's decision in Case
14 07-E-0523, the Company was allowed rate recovery to
15 perform 12 system scans during the rate year commencing
16 April 1, 2008. The rate year ended March 31, 2009 and
17 during that rate year, the Company completed all 12
18 scans as mandated by the Commission.

19 The claims made by Mr. Schultz that the testing costs
20 requested are excessive and unsupported by the
21 confidential contract documentation supplied by the
22 Company is inaccurate. The purchase orders supplied

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1 indicate the contract rates effective at the time of
2 the filing and were the source of the rates used to
3 project the 2010 rate year component costs. In
4 addition, the Company's response to CPB-155 explicitly
5 shows how the rates were used to derive the costs

6 Q. On page 51, lines 7 - 13, Mr. Schultz calls the
7 Company's request for overtime "unjustified" because he
8 anticipates that with a decline in shocks, there should
9 be a decline in repair cost. Please comment on Mr.
10 Schultz's allegations.

11 A. The claims made by Mr. Schultz about the standby and
12 repair costs fail to take into account several factors.
13 As more scans are conducted, there has been a rise in
14 the number of conditions detected and consequently, an
15 increase in the need for site-safety and repairs which
16 will lead to an increased cost per scan or mile. Site
17 safety is one of the largest components of the cost of
18 this program. The detection and mitigation of more
19 conditions reduces the risk of exposure to the public
20 and thereby contributes to the decline in the number of
21 electric shocks reported. Mr. Schultz also fails to
22 recognize the issue of timing, where the 2008 calendar
23 year repair cost expenditures reflect the repair costs

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1 attributed to a lesser number of scans, and therefore,
2 stray voltage conditions, completed and corrected than
3 will be conducted over the course of the rate year.

4 Q. Please comment on Mr. Schultz's statement on page 50,
5 lines 12 - 15 that there should be a decline in the
6 cost per scan and/or per mile because the system scans
7 have resulted in voltage problems being discovered and
8 corrected.

9 A. The testing cost has the most impact on the overall
10 mobile stray voltage program cost. An increase in
11 costs is necessary if 13 scans are to be completed
12 during the rate year. Mr. Schultz fails to realize
13 that the costs associated with deploying the Stray
14 Voltage Detection vehicles remain, regardless of
15 whether any stray voltage conditions are detected. The
16 greater numbers of scans have resulted in the need for
17 increased repairs. There is no evidence to support Mr.
18 Schultz's expectation that there is an economy of scale
19 associated with Company repairs. If more conditions
20 are found, it does not mean that the rate to fix them
21 becomes cheaper.

22 Q. Does the Company agree with CPB's proposed reductions
23 to the Danger Tree request under the Line Clearance

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1 category?

2 A. No. Mr. Schultz reduces the projected program by
3 \$445,000, to \$700,000 on the grounds that the Company
4 has not aggressively pursued this program in the past
5 and therefore he questions whether the Company will
6 complete the program. He claims that tree trimming is
7 always sacrificed when costs get tight and notes that
8 this program was reduced in the austerity adjustments.
9 Put simply, he does not believe that the Company will
10 undertake this program.

11 There is no basis to support CPB comments that the
12 proposed incremental workload is not realistic. The
13 proposed additional 542 off right-of-way danger tree
14 removal represents just a 0.6% increase in trees to be
15 managed by the Company. This takes into account that
16 Con Edison's annual workload for the Line
17 Clearance tree trimming crews already includes
18 approximately 10,000 right-of-way tree removals,
19 trimming a minimum of 80,000 trees along the utility
20 easement and the removal of 944 off right-of-way danger
21 trees. As stated in DPS48-349, the Company will add 2-

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1 3 additional crews to this project in order to meet the
2 more aggressive goal.

3 The Company does not agree that this should be the
4 basis for future reductions since it is a relatively
5 low risk to reduce the program for a short time frame
6 but continued reductions would have a compounded impact
7 on our ability to maintain a safe and reliable system.
8 Continued deferring of this program will result in
9 significant tree related outages, equipment failures
10 and inconveniences to customers. As such, the Company
11 expects to undertake this program in the rate year.

12 Q. Do you agree with the recommendation presented by Mr.
13 Shultz as stated on page 52 of his testimony to reduce
14 the Electric Distribution Equipment Reconditioning and
15 Repair program by \$359,000?

16 A. No, we do not agree with Mr. Schultz's recommendation.
17 The Electric Distribution Equipment Reconditioning and
18 Repair program provides the least cost option for the
19 Company and its customers, and reducing this program
20 will actually increase costs borne by them. Mr.
21 Schultz's assumption that reducing O&M work and
22 increasing Capital work reduces costs is incorrect in

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1 the context of this program.

2 Q. Please explain.

3 A. Mr. Schultz states that the "major reason" for the
4 Company's increase is the assumption that it will
5 perform more work on network transformers, protectors,
6 and housings and undertake more field repairs. He then
7 questions whether or not some of this work may be
8 capital and makes an adjustment by recalculating the
9 five year average number of repairs by type. Based on
10 his five year by type average with a five percent
11 escalation adder, Mr. Schultz reduces the program by
12 \$359,000.

13 We believe Mr. Shultz's reduction was based on an
14 incorrect assumption that the Electric Distribution
15 Equipment Reconditioning and Repair program operates in
16 a 'vacuum' without impacting other programs. On the
17 contrary, the Electric Distribution Equipment
18 Reconditioning and Repair program directly impacts
19 expenditures in the Electric Operations Transformer
20 Purchase program.

21 Q. What is the Electric Operations Transformer Purchase
22 program?

23 A. As noted in our initial testimony (page 154, lines 15 -

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1 21), and the Redacted Testimony of the Staff
2 Infrastructure Investment Panel, (page 50, lines 5 -
3 13), the Electric Operations Transformer Purchase
4 program involves the purchase of new and/or
5 reconditioned primarily underground network
6 transformers, overhead transformers, pad-mount
7 transformers, emergency generators, and network
8 protectors to support the distribution system. For
9 this program, Con Edison has budgeted \$148.152 million,
10 \$144.606 million, \$138.640 million, \$138.750 million,
11 and \$137.250 million for the years 2009 through 2013,
12 respectively.

13 Q. How does the Electric Distribution Equipment
14 Recondition and Repair program impact the Electric
15 Operations Transformer Purchase program?

16 A. The Electric Distribution Equipment Recondition and
17 Repair program is comprised of reconditioning electric
18 distribution equipment such as, but not limited to,
19 underground network transformers, overhead
20 transformers, pad-mounted transformers, and network
21 protectors at the Astoria Transformer Shop, as well as
22 making repairs in the field to equipment such as, but
23 not limited to, underground network transformers and

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1 network protectors. Each underground network
2 transformer, overhead transformer, pad-mount
3 transformer, and network protector that is
4 reconditioned or repaired on the Electric Distribution
5 Equipment Recondition and Repair program directly
6 offsets a piece of equipment that needs to be purchased
7 on the Electric Operations Transformer Purchase
8 program. This is because if a piece of equipment is
9 reconditioned or repaired and put back into service,
10 the cost for the Company, and ultimately our customers
11 and ratepayers, is cheaper than purchasing new
12 equipment.

13 Q. What is the advantage to the Company and to customers
14 to recondition or repair equipment rather than purchase
15 it?

16 A. It is less expensive and more cost effective to
17 recondition or repair equipment rather than to purchase
18 it. For example, the cost of reconditioning
19 transformers is only 45% of the cost of purchasing
20 transformers and the cost of reconditioning network
21 protectors is only 85% of the cost of purchasing
22 network protectors (three year average 2007 - 2009).
23 Reducing the reconditioning and repair program at the

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1 expense of purchasing equipment would actually increase
2 costs borne by ratepayers.

3 Q. Do you agree with Mr. Shultz's concern as stated on
4 page 52 of his testimony, lines 8 - 9, regarding "the
5 increase in costs may be more related to a change in
6 capitalization rather than a change in performance?"

7 A. Mr. Schultz's observation that the increase in O&M
8 costs is due to a "change in capitalization" is
9 basically correct, in that the program change is to
10 perform more O&M reconditioning in place of Capital
11 reconditioning. The "increase" of \$335,000 noted in
12 his testimony on page 13, line two, represents a
13 'shift' of existing labor from Capital reconditioning
14 to O&M reconditioning.

15 Q. What is the advantage to the Company and to ratepayers
16 to perform more O&M reconditioning rather than Capital
17 reconditioning?

18 A. O&M reconditioning is the least cost option for our
19 customers and ratepayers and is performed at a discount
20 compared to Capital reconditioning. Capital
21 reconditioning of transformers costs 2.73 times the
22 cost of O&M reconditioning transformers and Capital
23 reconditioning of network protectors costs 1.61 times

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1 the cost of O&M reconditioning of network protectors
2 (three year average, 2007-2009). In essence, Mr.
3 Shultz's recommended reduction of \$359,000 in O&M
4 reconditioning transformers and network protectors
5 would require that the same number of transformers and
6 network protectors be reconditioned as Capital at a
7 cost of \$659,400. Again, as noted above, reducing the
8 O&M reconditioning and repair program at the expense of
9 Capital reconditioning actually increases costs borne
10 by ratepayers.

11

12 Q. How does the Company manage the Electric Distribution
13 Equipment Reconditioning and Repair program in
14 conjunction with the Electric Operations Transformer
15 Purchase Program?

16 A. The Company manages its work on a least cost basis to
17 achieve the greatest cost avoidance. First, we would
18 like to maximize the number of field repairs made,
19 because these provide the greatest cost avoidance - not
20 only do these repairs eliminate purchasing replacement
21 equipment, but they also eliminate the extensive
22 associated labor costs to remove the defective
23 equipment and install the replacement equipment.

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1 Secondly, we would like to maximize the amount of O&M
2 reconditioning instead of Capital reconditioning for
3 several reasons. O&M reconditioning takes less time
4 and requires less material than Capital reconditioning
5 therefore the cost avoidance seen by our customers and
6 ratepayers is higher. Additionally, because O&M
7 reconditioning takes less time than Capital
8 reconditioning the Company is able to recondition more
9 items of equipment with the same human resource pool,
10 offsetting more purchases of equipment on the Electric
11 Operations Transformer Purchase program - essentially a
12 "win-win" for the Company, its customers, and
13 ratepayers.

14 Q. Mr. Schultz's states that the trip coil monitor program
15 and unit substation repairs and inspections have
16 significant increases since the 2008 expense level.
17 Please comment.

18 A. In 2008, the design of the trip circuit monitor was
19 reviewed and found that an off the shelf monitor
20 existed and was determined to be more reliable and less
21 costly to install and test. In order to ensure the most
22 effective and reliable program, the program was delayed
23 to allow for station testing and evaluation. The new

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1 monitor was installed at one station and successfully
2 tested. Based on these results, we will continue to
3 install the new monitors throughout the system. In
4 2008, the Unit Substation repairs and inspections were
5 delayed due to higher priority projects and system
6 conditions. The increase of \$449,000 increase above the
7 actual 2008 expenditures of \$1,283,000 represents an
8 increase of approximately 35%. The scopes of work at
9 various Unit Substations are required to reduce the
10 potential for safety hazards to employees and the
11 general public.

12 Q. Mr. Schultz states that the number of inspections vary
13 from year to year and apparently an equal amount is not
14 done annually to meet the Company's five-year overhead
15 inspection requirement. Please comment.

16

17 A. As per all submitted documentation, the Company plans
18 to inspect 60,000 poles per year in order to maintain
19 the 5 year inspection cycle. It is not appropriate to
20 assume that the number of inspections will vary from
21 year to year going forward especially with the order
22 revision of December 15th, 2008 dictating that the
23 Company must repair defects found on the system within

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1 the time limitation listed below:

2 Level 1 - 7 Days

3 Level 2 - 1 Year

4 Level 3 - 3 Years

5

6 Q. On page 49, line 9-12, Mr. Schultz states that "It is not
7 appropriate to assume that the rate year cost for
8 inspecting 60,000 poles and needed repairs would cost
9 \$3.226 million when 2009 year-to-date expense including
10 repairs is \$271,032 for 45,315 poles." Please comment.

11 A. The Company has stated that Level 2 and Level 3 repairs
12 have been deferred until the new tracking system is in
13 place; the system was deployed on August 31, 2009 and
14 the Company is focused on addressing the Level 2 and 3
15 pending work. The majority of expenditure as of July
16 2009 is only for inspections and is not indicative of
17 the projective costs which include repair of Level 2
18 and Level 3 defects. As of June 30, 2009 we have
19 identified 7,053 defects (Levels 2 and 3) through the
20 inspection of 45,315 poles. The \$3.226 will include
21 the inspections, Level 1, 2, 3 repairs, and completing
22 any backlog of Level 2 or 3 repairs from 2009.

23 Q. Do you agree when Mr. Schultz states that it is not

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1 appropriate to assume that the 2008 test year overtime
2 would increase since it is a variable cost and made an
3 associated adjustment?

4 A. The Company strongly disagrees with this assessment.
5 The assumptions were based on 2005 actual findings. In
6 the future, we will be able to provide a more detailed
7 analysis. As stated before, since we started tracking
8 defects, we have identified 7,053 defects (Levels 2 and
9 3) through the inspection of 45,315 poles, this leads
10 us to believe that the assumed estimate is very
11 conservative. The increase in overtime is due to the
12 completion of all defects - Levels 1, 2, and 3, whereas
13 up to this point in 2009 all our costs are due to
14 inspections and not repairs.

15 Q. What is the next area of your rebuttal testimony?

16 A. We will address the testimony of Mr. Thomas G.
17 Bourgeois on behalf of the Pace Energy and Climate
18 Center.

19 Q. Could you please summarize the recommendation made by
20 Mr. Bourgeois?

21 A. He proposes that starting with its next rate case, as
22 an element of its *prima facie* case for recovery of T&D
23 costs, Con Edison should be required to demonstrate its

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1 evaluation of distributed generation ("DG") as an
2 alternative to transmission and distribution ("T&D")
3 investment or, in the alternative, Con Edison should be
4 required to conduct a DG pilot.

5 Q. Does the Company agree with this recommendation?

6 A. No. Mr. Bourgeois' principal recommendation is
7 overbroad and would be impossible to apply in practice.
8 In any event, it should not be considered in this
9 proceeding. The use of demand side management ("DSM")
10 measures, including energy efficiency, demand response
11 and DG, is currently being considered in the
12 Commission's Energy Efficiency Portfolio Standard
13 (EEPS) proceeding (Case 07-M-0548), and in the
14 Proceeding of the Commission to consider Demand
15 Response Initiatives, Case 09-E-0115 (DR Proceeding),
16 and it is in these proceedings that this kind of
17 recommendation should be considered. The Company also
18 notes that in the DR Proceeding, it has also submitted
19 a petition for approval of demand response pilot
20 programs, and Mr. Bourgeois could also potentially
21 raise his claims there to the extent that he is
22 proposing to increase the use of DG for demand response
23 -- his testimony appears to be focused on combined heat

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1 and power (CHP), which is usually operated as a base
2 load, but may be available for demand response. The
3 Commission should also reject his proposal to have Con
4 Edison conduct a DG pilot because the Company has
5 already conducted a DG pilot, and Mr. Bourgeois fails
6 to demonstrate that an additional pilot is warranted at
7 this time. Con Edison has been proactively seeking to
8 consider DG in its planning and will continue to
9 consider DG as part of the Company's long-range
10 electric plan.

11 COMPANY DG POLICY

12 Q. Does the Company support the use of DG?

13 A. Yes. The Company's policy is that customers should have
14 the ability to choose DG as a method of supplying their
15 energy needs and that the Company should have fair and
16 reasonable procedures for DG interconnection. But the
17 Company does not believe that DG should be preferred
18 over energy efficiency or demand response for reducing
19 a customer's energy needs and does not believe that DG
20 should be provided with incentives that do not meet the
21 Commission's cost-effectiveness tests. Instead, we
22 believe the Company's proper role is to provide a level
23 playing field that does not favor one technology over

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1 another by creating more generous incentives for
2 specific technologies, particularly technologies that
3 contribute to greenhouse gas and other emissions, with
4 potentially local impacts.

5 Q. Why does the Company believe that DG should not be
6 preferred over energy efficiency or demand response?

7 A. Most types of DG currently employed use fossil fuel and
8 are, therefore, an air pollutant emissions source.
9 Indeed, Mr. Bourgeois' testimony focuses on the use of
10 fossil-fueled DG as an alternative to T&D investment.
11 We note that the Commission itself has expressed
12 concerns over the environmental impacts of DG. It
13 stated in the EEPS proceeding (p. 10, n.8) that
14 "[a]lthough the role of demand response programs -
15 versus permanent energy efficiency programs - remains
16 an issue, it is clear that this proceeding will not
17 encompass demand response that substitutes one
18 generation source for another without regard to
19 efficiency or emissions." Accordingly, DG should be
20 compared to other methods of "fuel-switching" for
21 reducing a customer's electric load, such as the use of
22 steam chillers within the footprint of Con Edison's
23 steam system, or solar panels or geothermal.

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1 Q. How does DG compare to central station generation?

2 A. Emissions from central generating stations are subject
3 to New York State Department of Environmental
4 Conservation (NYDEC) permitting regulations that
5 require compliance with specific air pollution emission
6 limits, installation of continuous emissions monitoring
7 systems to demonstrate real-time compliance and ongoing
8 control, and maintenance of associated generating
9 systems (this includes central station facilities such
10 as Con Edison's East River Generating Station, which is
11 a combined steam and electric generating facility
12 comprised of both steam-only and cogeneration unit).
13 Many CHP systems in buildings typically have rated heat
14 inputs of less than 10 MMBtu/hr and, therefore, are not
15 subject to any air emission regulations with the
16 exception of NYC Department of Environmental Protection
17 permitting requirements. Since the majority of on-site
18 boilers are exempt from these air emission regulations,
19 their performance is not typically verified by
20 regulatory agencies. As the equipment ages, the
21 potential exists that emission rates may increase
22 without the knowledge of both the operators and the
23 regulatory agencies. We also note that while the State

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

ELECTRIC

1 has recognized the need to adopt air emissions
2 regulations for DG, it has not done so to date. We
3 would also note that the Con Edison East River
4 Cogeneration NOx emissions are approximately 0.7
5 lb/MWh, well below that of new natural-gas fired DG
6 equipment - a typical 100kW CHP operates at 1.5 lb/MWh
7 -- and well below the DEC proposed 2.2 lb/MWh for even
8 the cleanest natural gas burning DG. It should be
9 noted that the current limits (5.9 - 8.9 lb/MWh
10 depending on the engine type) are not strictly
11 monitored or clearly required for non-engine types of
12 DG.

13 Q. Mr. Bourgeois states that he supports clean DG. Does he
14 define clean DG?

15 A. Mr. Bourgeois does not define clean DG in his
16 testimony. And we note that while CHP does have some
17 environmental benefits over some older central station
18 generation, the environmental permitting requirements
19 for DG are much less stringent than they are for new
20 central station power plants, especially those located
21 in New York City, even though there are studies
22 suggesting that environmental permitting requirements
23 for DG should be more stringent than those for central

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 station generation plants because DG has lower stack
2 heights and emission velocities, which can increase
3 pollutant concentrations at ground level in the
4 vicinity of the DG emissions source.¹ Accordingly, to
5 the extent that there is a need for new generation that
6 serves incremental load, it would be better to serve
7 that load with new combined-cycle natural gas
8 generation (or wind or solar) rather than fossil-fuel
9 fired DG.

10 Q. Mr. Bourgeois mentions that PlaNYC has a goal of 800 MW
11 of clean DG by 2030 and that there are barriers to
12 reaching that goal. Does Con Edison support the PlaNYC
13 goal?

14 A. First, we note it is unclear what PlaNYC means by clean
15 DG because it also does not provide a precise
16 definition of clean DG. It also appears that the
17 PlaNYC intent is for DG to provide for efficient
18 district energy systems at appropriate sites in New
19 York City rather than as individual DG projects
20 designed to defer T&D (see p. 11). We also note that

¹ See UC Energy Institute "Quantifying the Air Pollution Exposure Consequences of Distributed Electricity Generation," Garvin A. Heath,

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1 Mr. Bourgeois fails to mention that the PlaNYC interim
2 goal is 100 MW of clean DG by 2015 and a substantial
3 amount of DG has been installed or is in the process of
4 being interconnected. This year alone we expect about
5 70 MW of customer-owned DG to be interconnected over
6 the next year.

7 Q. What has Con Edison been doing to facilitate DG
8 interconnection?

9 A. We have had training seminars for DG customers and
10 vendors and solar stakeholders, and provide one-on-one
11 technical and administrative support. Our efforts in
12 this regard have been supported as proactive and
13 innovative by CHP and solar developers and
14 stakeholders. Con Edison has been working hard to
15 remove actual and perceived barriers, for example, by
16 designing favorable DG rates - such as the Riders J and
17 H gas rates and the SC14 electric standby rate. We
18 continue to streamline the interconnection process by
19 working with other utilities and the Commission to
20 facilitate and shorten the process for smaller
21 projects. For example, we expect to have the

Patrick W. Granvold, Abigail S. Hoats and William W. Nazaroff

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1 application process online by January 2010.

2 We also provide a website which details the technical

3 and administrative requirements for interconnection and

4 shows fault current maps that indicate areas where

5 certain types of DG (synchronous machines) are

6 permitted without additional protection measures. Con

7 Edison also has a DG technical expert and a DG

8 Ombudsperson who provide training seminars for DG

9 developers, PV installers, and other stakeholders.

10 These DG experts also assist with specific

11 interconnection-related questions and concerns. We

12 continue efforts to explore technical solutions for DG

13 interconnection - such as current-limiting protection

14 devices, advanced inverter technologies, and customized

15 relay protection schemes.

16 Q. Are there incentives available for investment in CHP?

17 A. Yes. NYSERDA already provides incentives for CHP,

18 funded by ratepayers, and there are favorable tax

19 incentives that would be applicable to a NYSERDA funded

20 DG facility or a facility that chooses to participate

21 in a Con Edison DSM program.

(November 2005).

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 PACE'S RECOMMENDATIONS

2 Q. Mr. Bourgeois recommends that Con Edison should be
3 required to consider DG as an alternative to T&D
4 investment. Does Con Edison agree?

5 A. No. First, Mr. Bourgeois' recommendation is overbroad
6 and would be impossible to apply in practice as Con
7 Edison simply could not consider DG as an alternative
8 for every single investment in the T&D system. There
9 would not be time to do so for many investments, and it
10 would not make sense to spend time and resources to
11 consider for any investment other than the larger
12 investments. This is why DG is best considered for T&D
13 deferral in the Company's Targeted DSM program or in
14 the Company's proposed Network Relief Program (which
15 was proposed in the DR Proceeding and would target
16 specific networks in need of system relief) and not as
17 a separate T&D deferral effort. Accordingly, the EEPS
18 proceeding and the DR Proceeding are the proper venues
19 for consideration of DG as a vehicle for T&D deferral
20 because Con Edison has filed its targeted DSM program
21 for approval in the EEPS proceeding and its Network
22 Relief Program in the DR Proceeding, and these programs
23 allow for the use of DG to defer T&D investment. The

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1 EEPS proceeding, which provides Con Edison with
2 incentives for achieving energy efficiency, is also the
3 proper place for determining whether Con Edison should
4 have incentives for DG in addition to or part of its
5 energy efficiency incentives.

6 Q. Has the existing Targeted DSM Program been evaluated?

7 A. Yes. A third party independent evaluation was conducted
8 by Navigant, Inc. The evaluation found that the
9 "Targeted DSM program is unique and path breaking.
10 While several utilities have had limited pilots to use
11 DSM or distributed generation (DG) to defer T&D
12 upgrades, the Con Edison program is the first large-
13 scale program to defer T&D investments through targeted
14 and permanent load reductions. Uniquely, Con Edison now
15 includes targeted DSM as a standard option in their T&D
16 planning. Further, Con Edison uses T&D deferral to
17 create added value for DSM load reduction." (Evaluation
18 of Targeted Demand Side Management Program, Navigant
19 Consulting Inc.).

20 Q. Doesn't Mr. Bourgeois have complaints about how DG is
21 treated in the Targeted Program?

22 A. Yes, but those complaints are properly raised in the
23 EEPS proceeding or the DR Proceeding, as appropriate.

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 Q. Do you agree with Mr. Bourgeois' complaints about how
2 DG is treated in the Targeted Program, in particular
3 that the Targeted Program's "physical assurance"
4 requirement is a barrier for DG participation?

5 A. No. While Mr. Bourgeois complains that DG has not
6 participated to date in the Targeted Program, the
7 requirement for 100% physical assurance makes sense
8 because Con Edison is using this program to reduce peak
9 demand while maintaining reliability. Indeed Navigant
10 stated with respect to the physical assurance
11 requirement that, "This approach, approved and adopted
12 elsewhere in the U.S., is needed to assure certainty of
13 load reduction at the time of the load area peak." (p.
14 6). And in its recommendations, Navigant endorsed
15 continuation of the physical assurance requirement,
16 stating that the "Company should investigate the
17 feasibility and customer acceptance of demand response
18 (DR) that can be dispatched for both system capacity
19 and network/load area requirements. *This could include*
20 *distributed generation, provided that Con Edison would*
21 *have direct control of the device or equivalent load to*
22 *ensure capacity is available when needed.*" [Program
23 Design Recommendation 8, p. 10. Emphasis added]. Con

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1 Edison applies the same physical assurance requirement
2 to steam chillers. Moreover, the fact that DG has not
3 participated does not demonstrate that the physical
4 assurance barrier is preventing DG from participating.
5 The third party evaluation of the targeted DSM program
6 found that physical assurance was not the primary
7 barrier but rather that "Non-lighting measures such as
8 HVAC and Distributed Generation, while possibly cost-
9 effective, require specialized expertise (e.g.,
10 licensed electricians), greater investment risk, and
11 longer lead-times" that present a significant concern
12 for developers. This is not to say that DG should not
13 or cannot participate but that other "lower hanging
14 fruit" solutions have been the first to be implemented

15 Q. Mr. Bourgeois has also suggested that the Commission
16 require Con Edison to undertake a pilot program to
17 investigate a combination of utility and customer owned
18 DG as an effective means of avoiding or delaying T&D
19 investment. Does Con Edison agree?

20 A. The pilot previously undertaken by Con Edison over the
21 three-year period from 2001 through 2003 does not
22 warrant revisiting. The pilot was rigorous. No RFP
23 resulted in actual projects, but this was due to the

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 cost of DG as compared to the carrying cost of the
2 particular utility T&D investment. Mr. Bourgeois does
3 not demonstrate that there has been a material change
4 in the economic factors underlying DG since Con Edison
5 completed the DG pilot. And we recommended that the
6 third-party DG be considered in the Targeted Program.

7 Q. Mr. Bourgeois states that Con Edison has studied cases
8 showing that certain DG projects are economic for T&D
9 deferral. Why has Con Edison not pursued such
10 projects?

11 A. Though DG may be an economic choice in some cases, Con
12 Edison currently uses the RFP process in the Targeted
13 DSM Program for selecting the solutions for T&D
14 deferral. Con Edison has, on a few occasions, used DG
15 for load relief, connecting mobile diesel generators
16 for several months at a time at area substations as a
17 temporary solution pending execution of permanent load
18 relief. For example, in 2006 eight locations were
19 identified where a mobile generator would provide load
20 relief for the three summer months. At one of these
21 locations, it was later determined that a step down
22 transformer, with more benign environmental impact
23 could be used. Our approach would be continue to

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 deploy DG where it makes sense.

2 Q. Mr. Bourgeois suggests that a pilot undertaken by
3 National Grid be a model for the proposed Con Edison
4 pilot. Do you agree?

5 A. No. The results of the National Grid pilot to date do
6 not, to our knowledge, warrant looking to that program
7 as a model. An Energy Insights article states that the
8 pilot achieved only a modest reduction. National Grid
9 learned that at all business sizes cash flow or capital
10 were issues and that the expensive natural gas micro-
11 CHP systems that it supported were only economic when
12 replacing inefficient furnaces - for example boiler
13 based systems that were no longer commercially
14 available. The micro-CHP machines also vent at the
15 street level, again raising the concern about lung-
16 level emissions.

17 Q. Mr. Bourgeois suggests that the Company is not
18 sufficiently proactive on DG. Do you agree?

19 A. No. The studies referred to by Mr. Bourgeois concern
20 the potential of utility-owned DG to: (1) defer T&D
21 upgrades; and (2) the use of DG for temporary peak load
22 reduction in Westchester and at the Chelsea substation
23 in Manhattan. These studies illustrate that Con Edison

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE

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1 does currently consider DG for at least temporary peak
2 load management. We are also working on a 'virtual
3 power plant' pilot project with Verizon, the Department
4 of Energy, and the Electric Power Research Institute to
5 determine communication and dispatch/control technology
6 that will allow DG to participate in the Con Edison DR
7 and NYISO DR and ancillary services markets. Con
8 Edison has also proposed a DG solar pilot that was on
9 hold due to the current economic conditions and
10 austerity measures, but the Company is also seeking
11 federal stimulus funds for solar initiatives as well as
12 Smart Grid initiatives that would facilitate the
13 integration of solar and other clean DG technologies.
14 Clearly, Con Edison does not need to be required to
15 pursue pilots to determine the effectiveness and value
16 of clean DG. We have and will continue to pursue such
17 pilots on our own.

18 Q. What has Con Edison learned from the initiatives that
19 it has conducted to date?

20 A. Clean and renewable DG, if the technology matures and
21 costs come down, will have a greater presence in our
22 T&D plan in the future. But we do not believe it makes
23 sense now to deploy DG on a wide scale basis. Con

INFRASTRUCTURE INVESTMENT PANEL - REBUTTAL/UPDATE
ELECTRIC

1 Edison will also consider the role of DG as part of the
2 Electric Long Range Plan (ELRP) as a potential solution
3 - where it makes the most sense from a technical,
4 economic and environmental perspective.

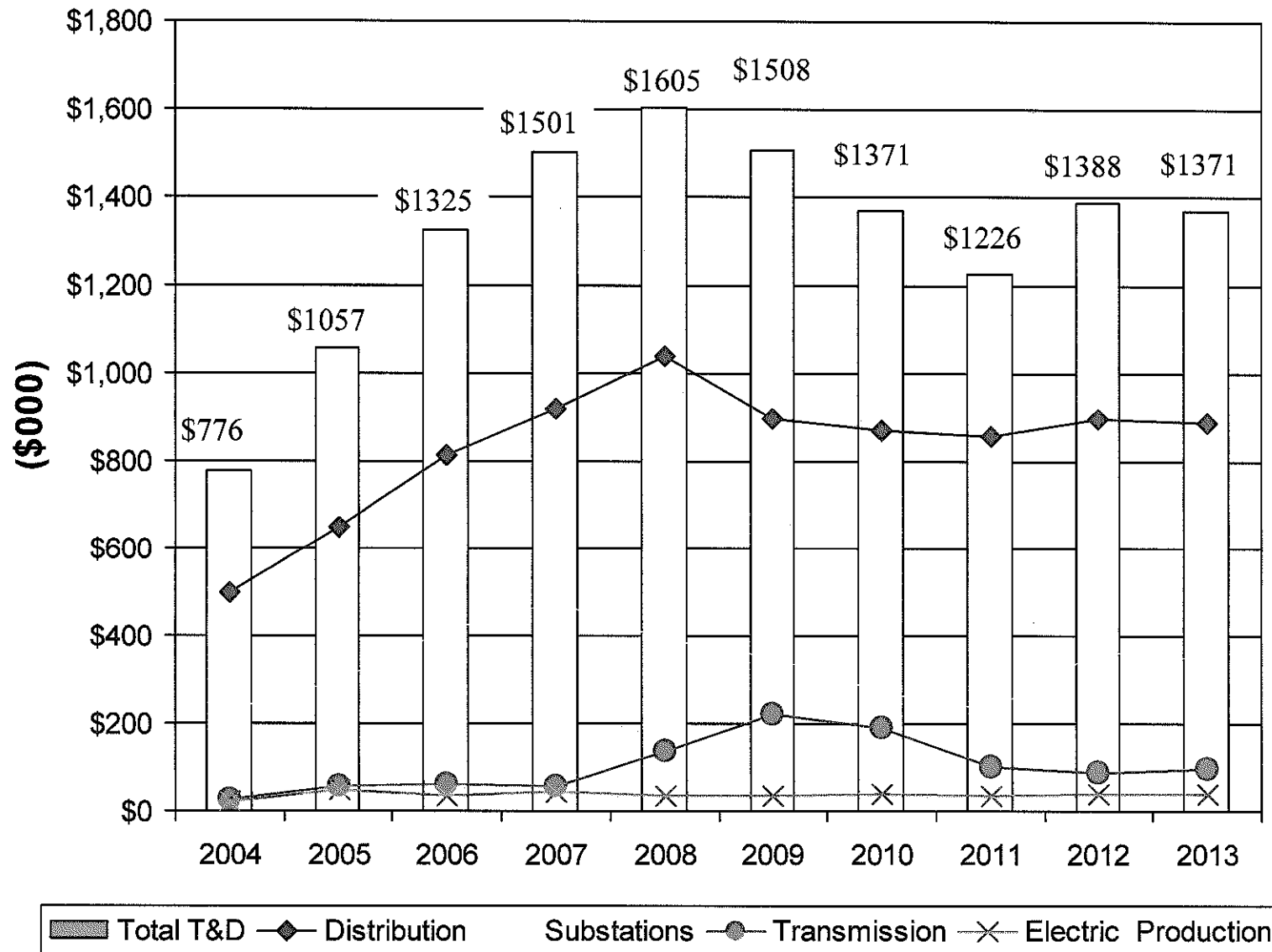
5 Q. Does this conclude the Panel's rebuttal and update
6 testimony?

7 A. Yes.

Capital Funding - (Historical & Required)

Revised Exhibit (IIP-1)

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS					
		\$000s			
		Rate Case Submission			
Page	DESCRIPTION	2010	2011	2012	3 YEAR TOTAL
	INCREASED CUSTOMER DEMAND	\$ 57,985	\$ 25,300	\$ 144,300	\$ 227,585
2	Emergent Load Relief Program	1,300	1,300	1,300	3,900
3	Newtown-Establish Station	42,000	-	-	42,000
4	Parkchester-Install 3rd Cap Bank	-	1,000	1,000	2,000
5	Parkchester-Install 4th Transformer	-	3,000	12,000	15,000
6	Woodrow-Install Third Transformer And Fresh Kills Expand 138kV Station	12,185	-	-	12,185
7	York-Establish New Area Substation	2,500	20,000	130,000	152,500
	GENERATION INTERCONNECTION				
8	Astoria East-Install Phase Angle Regulator	-	-	-	-
	Corona-Install Series Reactor	-	-	-	-
	Sub-Total	\$ 57,985	\$ 25,300	\$ 144,300	\$ 227,585

Project/Program Title	Generation Interconnection: Astoria (PAR) & Corona (reactor)
Status	On Hold
Estimated Service Date	Based on Next Developer to Interconnect at Astoria.
Work Plan Category	Increased Customer Demand

Removed

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS					
Page	DESCRIPTION	\$000s			
		Rate Case Submission			
		2010	2011	2012	3 YEAR TOTAL
	SYSTEM AND COMPONENT PERFORMANCE	\$ 183,450	\$ 180,940	\$ 193,370	\$ 557,760
	EQUIPMENT				
3	138kV Circuit Breaker Program Upgrade Program	11,700	11,700	11,700	35,100
7	345kV Circuit Breaker Upgrade Program	5,000	5,000	5,000	15,000
10	Circuit Switcher Replacement Program	500	500	500	1,500
11	Condition Based Monitoring Equipment	250	250	250	750
13	Corona - Breaker Addition (6S and 8X)	2,650	-	-	2,650
14	Elmsford-Upgrade of Elmsford - Substation	32,000	27,740	1,750	61,490
16	Failed Equipment Other Than Transformers	1,500	1,500	1,500	4,500
17	Failed Transformer Program	25,800	24,700	23,000	73,500
19	Replace Disconnect Switches	4,600	4,800	4,800	14,200
22	Replace Overdutied 13/27kV Circuit Breaker Programs	10,800	10,800	10,800	32,400
25	Transformer Replacement Programs	20,500	20,000	21,000	61,500
	Sub-Total	\$ 115,300	\$ 106,990	\$ 80,300	\$ 302,590
	RELAY				
27	Control Cable Upgrade Program	1,000	1,000	1,000	3,000
29	Relay Modifications	5,500	5,500	5,500	16,500
33	Upgrade Analog Circuits To Digital Fiber	2,000	1,800	-	3,800
35	Relay Protection System Redundancy (Single Point of Failure)	-	-	30,000	30,000
	Sub-Total	\$ 8,500	\$ 8,300	\$ 36,500	\$ 53,300

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS					
Page	DESCRIPTION	\$000s			
		Rate Case Submission			3 YEAR TOTAL
		2010	2011	2012	
	MISCELLANEOUS COMPONENTS				
37	Additional G&T Devices	500	500	500	1,500
38	Area Substation Reliability And Auto Ground Circuit Switchers	10,500	10,500	10,500	31,500
40	Capacitor Cable Upgrade Program	3,000	3,000	1,000	7,000
42	Category Alarms	2,250	2,250	2,250	6,750
44	Construct Relay Enclosure Houses	1,500	1,500	1,500	4,500
46	Corona Settlement	1,000	-	-	1,000
48	DC System Upgrade Program	3,500	3,500	3,500	10,500
51	Diesels / Blackstart Restoration (Phase 2) - Upgrade Station L & P	1,000	1,000	1,000	3,000
53	E. 13th Street - Alarm Panel Replacement and Control Systems	-	1,500	4,500	6,000
54	E179th Street-Substation - Bus Section Upgrade Program	6,000	15,000	25,000	46,000
55	East River-Protection System Upgrade	3,500	3,100	2,520	9,120
57	Facility Improvement Program	6,000	6,000	6,000	18,000
61	Fire Suppression System Upgrades	6,000	6,000	6,000	18,000
63	High Voltage Test Sets	5,000	3,000	4,000	12,000
66	Rapid Restore Enhancements- Expansion of TOMS	200	-	-	200
68	Reinforced Ground Grid	700	700	700	2,100
70	Revenue Metering Upgrade	500	500	-	1,000
72	Roof Replacement Program	3,000	2,100	2,100	7,200
74	Small Capital Equipment Program	3,000	3,000	3,000	9,000
77	Substation Loss Contingency	2,000	2,000	2,000	6,000
79	Switchgear Enclosure Upgrade Program	500	500	500	1,500
	Sub-Total	\$ 59,650	\$ 65,650	\$ 76,570	\$ 201,870

Project/Program Title	Relay Protection System Redundancy(Single Point of Failure)
Priority Number	Regulatory Requirement – NERC / NPCC
Status	Planning/Concept
Estimated Service Date	2011 - 2019
Work Plan Category	System and Component Performance

Work Description:

The project will provide addition of components on 138 kV switching stations, such that a failure or removal of any one of the following components of Protection Systems will not prevent achieving the Bulk Electric System (BES) performance requirements identified in the NERC TPL Reliability Standards:

- Any single AC current source and/or related input to the relay protection groups associated with a single element.
- Any single secondary AC voltage source and/or related input to the relay protection groups associated with a single element, when such voltage inputs are needed excluding the complete loss of an entire CCVT, VT, or similar device with multiple secondary windings.
- Any single protective relay that is used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
- Any single communication channel and/or any single piece of related communications equipment, used for the relay protection groups associated with a single element, when such communication between protective relays is needed to satisfy the BES performance requirements.
- Communications functions for communications-aided protection functions (i.e., pilot relaying systems).
- Communications functions for communications-directed protection functions (i.e., direct transfer trip).
- The failure or removal of any single element of the DC control circuitry that is used relay protection groups associated with a single element.
- The failure or removal of any single auxiliary relay that is used for any of the above functions.
- The failure or removal of any single breaker trip coil for any breaker operated by the Protection System (If a single trip coil is used, the breaker failure scheme DC must be independent of the breaker trip coil DC).
- The failure or removal of any single station battery, or single charger, or other single DC source. In some cases, this may require re-connecting existing DC branch circuits.

Note the above scope does not include expansion of existing control rooms, or outdoor relay panel line-ups, because we anticipate this will not be required to meet the requirements of the future NERC Reliability Standard..

Justification:

This project is intended to meet the expected requirements of the future NERC Reliability Standard, being developed by NERC Project 2009-07. Furthermore, we anticipate that the NERC definition of the Bulk Electric System (BES) will be adopted within the NPCC Region. For Con Edison, we anticipate that the BES will include, at least, all 138 kV transmission substations and portions of the East River Generating Station. At this time, the implementation schedule and implementation plan requirements for complying with the future Reliability Standard are unknown.

Estimated Completion Date:

This is a multi-year project that is planned to be implemented over a 10-year interval.

Status:

This project is in the planning/concept stage. Project scope will determine when the first draft standard is posted by NERC Project 2009-07 Standard Drafting Team.

Funding (\$000):

A review of our facilities indicates that approximately \$350M will be needed to implement all the changes needed by this project. Therefore we have extended the program's timeline to 10 years (beginning in 2010).

Forecast 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	5-year Forecast 2009 -2013
-	2,000	8,000	30,000	40,000	80,000

Addendum

In light of the fact that the NERC Project 2009-07 standards are still early stages of development, we have moved back the projected start of this program to 2012. This allows approximately 3 years between introduction of the proposed standards and the actual implementation of them by NERC. This is fairly consistent with previous timetables of similar standards. It is possible that actual implementation of the standard could change. In this event, we will adjust the expected program start date accordingly.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast 2010 -2013
-	-	30,000	40,000	70,000

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS
TRANSMISSION OPERATIONS CAPITAL PROJECTS / PROGRAMS

Page	DESCRIPTION	<u>\$000s</u>			
		Rate Case Submission			
		2010	2011	2012	3 Year Total
	SYSTEM AND COMPONENT PERFORMANCE	\$ 22,430	\$ 33,910	\$ 67,680	\$ 124,020
82	Feeder 34182/4	-	-	3,000	3,000
83	Manhattan-Replace 69kV Feeders On QBB	-	-	3,000	3,000
84	Sprain Brook - W 49th St-Feeder M51	-	-	-	-
85	Staten Island-Feeders 38R51 And 38R52	-	4,210	13,000	17,210
87	Emergent Transmission Reliability	10,000	10,000	10,000	30,000
89	Re-Conductor Dunwoodie – Sprain Brook Transmission Corridor	-	5,400	5,280	10,680
91	Reinforce Hudson River Crossing Towers	1,800	1,800		3,600
93	Replace Feeder 69M41 & 69M45	1,000	5,000	18,000	24,000
94	Replacement of Feeders 18001 & 18002	2,180	-	8,000	10,180
95	Transmission Feeder Failures	5,000	5,000	5,000	15,000
96	Upgrade Overhead 345kV Transmission Structures	2,200	2,300	2,400	6,900
98	Phasor Measuring Units for SCADA Real Time Operation	250	200	-	450
	Sub-Total	\$ 22,430	\$ 33,910	\$ 67,680	\$ 124,020

2010 Capital – System & Transmission Operations - Transmission Operations

Revised Exhibit (IIP-4)

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Project/Program Title	Sprain Brook – W. 49 th St. - Feeder M51
Status	Planning, Engineering and Laboratory Dissection
Estimated Service Date	December 2008 and following
Work Plan Category	System and Component Performance

Work Description:

The proposed project involves the replacement of one or more targeted sections (between two manholes) of cable on 345kV Feeder M51. The sections selected for removal and examination will be based on the results of dynamic simulation software, field feasibility, community quality of life concerns and failure history. The removed sections will be examined in the field for abnormality, particularly for signs of thermo mechanical bending (TMB) development. Following the field examination, several samples of the cable will be selected for detailed laboratory dissection and analysis. In addition to aiding the development of the dynamic simulation software, the analysis of the removed sections will be used to study whether there is a generic problem with this cable type on Feeder M51.

Justification:

Feeder M51 has experienced 6 cable failures since 1999. Four of these failures occurred on cable sections (i.e. cable located between manholes) and are attributed to TMB. To date no reliable and proven technique is available to determine whether or not this failure trend will continue. The scope of this project entails the continued development of the computer software for the Dynamic Modeling and Simulation of the feeder. The results of the simulation will be compared to historical failures for purposes of verifying the model. If successful, the model will be used to rank all sections relative to the possibility of future failures. The section identified as being the most prone to a potential future failure will then be removed for inspection. The inspection of the removed section will aid in verifying the accuracy of the simulation program and provide a sample to make a qualitative assessment of the condition of the feeder.

Estimated Completion Date:

First cable section was removed in the fourth quarter of 2008 and field and laboratory dissection and analysis are in progress.

Status:

Evaluation of the laboratory results are in progress. Results are expected in the second quarter 2009 at which time the results will be used to evaluate the Dynamic Modeling and Simulation model. Tentatively, a second cable section is scheduled for removal and subsequent laboratory analysis in 2010.

Funding: (\$000s)

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	1,973

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
-	3,000	-	-	-	3,000

Addendum

Evaluation of the laboratory results are still in progress. Final reports from two of the three consultants have been received and the analysis from the third consultant is in progress with an anticipated completion by the forth quarter of 2009. The laboratory analysis from the three independent cable consultants will be used to evaluate the Dynamic Modeling and Simulation model. The removal and laboratory analysis of a second cable section was originally planned for 2009 and was deferred to 2010. Staff has proposed to further defer this project to 2011. Therefore, based on this, a second cable section is scheduled for removal and subsequent laboratory analysis in rate year 2011.

Funding: (\$000s)

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
-	-	-	-	-

2010 Capital – System and Transmission Operations / Transmission Operations

Revised Exhibit (IIP-4)

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Project/Program Title	Replace Compression Fittings and Conductor on Feeders 99941 and 99942 - Dunwoodie to Sprain Brook Transmission Corridor.
Status	On-going
Estimated Service Date	On-going
Work Plan Category	System and Component Performance

Work Description:

This program involves the replacement of the compression fittings and conductor on the overhead 138kV feeders 99941 and 99942 on the E-Line between Dunwoodie and Sprain Brook substations. In addition to replacing the conductors, the shield wire, fittings, insulators and support hardware will be replaced. The proposed shield wire will have 48 pairs of fiber optic lines embedded to aid / enhance company communications for relay protection. The towers will be reinforced by replacing several structural elements on eleven (11) lattice towers to support the new conductors and upgrade the towers to the current NESC 2007 codes.

Units per Year: Various

Mandatory: No. This discretionary program proactively addresses aging infrastructure, reduces risk of additional connector failures, and increases system reliability.

High-level schedule: 2010 Material Ordering; 2011 Complete Feeder 99942 and 2012 complete feeder 99941. All work is feeder outage dependent.

Justification:

Feeders 99941 and 99942 consist of single-wire bundle 2156 MCM ACSR (aluminum conductor steel reinforced). Each of the 138 kV feeders, which are approximately 1.5 miles in length, was originally built in 1956 with single-wire bundle 1033 kcmil 54/7 ACSR conductor and later rebuilt and reinforced in 1965 when the portion of the line between Sprain Brook and Dunwoodie (approximately 1.5 circuit miles) was upgraded to larger single-wire bundle 2156 kcmil 84/19 ACSR conductors. Significant problems with compression fittings have surfaced on feeders 99941 and 99942. Thermographic inspection detected three dead end fittings operating at high temperatures. The dead end fittings were replaced in 2006. Subsequent testing at The National Electric Energy Testing, Research and Applications Center (NEETRAC) indicated that the fittings were either at end-of-life or could reasonably be expected to be at or near end-of-life in the near future. The NEETRAC report also indicated that the conductor does not meet minimum ASTM requirements, possibly as a result of a manufacturer defect. The conductor's aluminum strands show that annealing has occurred which is an indication of a history of thermal overloads on the line. Separate studies conducted in 1994 on line 398 also suggest that the splices should be reinforced / replaced. The splices on feeders 99941 and 99942 are similar to those on feeder 398.

- Alternatives: One alternative was to replace only the splices on the line. Financial analysis determined that it was cost effective to replace the splices, conductor and hardware between the two substations. This would significantly increase reliability.
- Risk of No Action: Additional hot spots, outages and reduced system reliability.
- Summary of Financial Benefits and Costs: Costs include materials (\$1600k), contractor labor (\$6000k), company labor including Engineering (\$1400k) and site restoration work (\$2000k).
- Non-financial Benefits (if applicable): There are two non-financial benefits associated with this program:
 1. This work increases employee safety since the reinforced tower components have less risk of failure when line constructors conduct routine and emergency tower maintenance work.

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2. This work increases system reliability since aging components are being replaced with new ones and this reduced feeder failures.

- Technical Evaluation/Analysis: Thermographic inspection detected three dead end fittings operating at high temperatures. The dead end fittings were replaced in 2006. Subsequent testing at The National Electric Energy Testing, Research and Applications Center (NEETRAC) indicated that the fittings were either at end-of-life or could reasonably be expected to be at or near end-of-life in the near future. The NEETRAC report also indicated that the conductor does not meet minimum ASTM requirements, possibly as a result of a manufacturer defect. The conductor's aluminum strands show that annealing has occurred which is an indication of a history of thermal overloads on the line. Separate studies conducted in 1994 on line 398 also suggest that the splices should be reinforced / replaced. The splices on feeders 99941 and 99942 are similar to those on feeder 398.
- Sensitivity Analysis (if applicable): Weather, material costs, outage restrictions and contractor availability could increase the cost of the project. The right of way (ROW) on which the work is to be performed is in particularly close proximity to a residential community in Yonkers, NY. Vegetation work and pre-construction work are required to ensure clear access to the towers. Therefore, additional safety precautions and site restoration activities are being implemented throughout the project, thus increasing costs.
- Project Relationships (if applicable): This project is related to the M29 feeder installation project. System reliability during the extended outages needed to replace the conductors on feeders 99941 and 99942 will be enhanced once M29 is energized and in service, scheduled for pre-summer 2011. Thus, the reconductoring project has been deferred with material procurement now scheduled for 2010 and construction taking place in 2011 and completed 2012.

Estimated Completion Date:

2012

Status: This project was included in the 2008 Rate Case submittal and completion dates are feeder outage dependent.

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	-

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009 – 2013
	500	5,400	4,780	-	10,680

Addendum

This capital program involves two major 138kV feeder outages which are scheduled in the 4th quarter of 2011. The materials need to be purchased in advance. Since the \$500,000 scheduled for this project in 2010 is for purchasing material, the purchase can be deferred to 2011 with minimal impact. However, if Staff's proposal were to be accepted, \$500,000 will be required in 2012 to complete the scope of planned work in

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2012. Staff proposes “deferring the project an additional year” and we take this to mean that Staff does not oppose expenditure of \$500,000 in 2012 to complete this project.

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009 – 2013
-	5,400	5,280	-	10,680

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Capital Programs

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Page	DESCRIPTION	Rate Case Submission			
		2010	2011	2012	3 Year Total 2009-2011
	System and Component Performance	\$ 426,168	\$ 415,047	\$ 445,653	\$ 1,286,868
128	Elmsford Refurbishment	-	1,300	2,000	3,300
129	59th Street Bridge Crossing	-	-	2,000	2,000
130	(Primary) Cable Crossings	8,000	8,000	9,000	25,000
139	HiPot	3,400	3,400	6,100	12,900
141	PILC	27,085	27,085	33,000	87,170
143	Transformer Remote Monitoring System 3rd Generation Transmitter	7,850	7,500	7,000	22,350
145	Sectionalizing Switches	3,562	3,562	4,501	11,625
148	Underground Secondary Reliability Program	37,422	40,866	50,009	128,297
151	Secondary Open Mains	139,245	129,871	129,871	398,987
153	Grounding Transformers	550	520	520	1,590
156	Shunt reactors	2,761	2,788	2,790	8,339
158	Network Reliability	21,323	22,145	26,545	70,013
160	Coastal Storm Risk Mitigation	1,000	1,000	3,000	5,000
162	Transformer Purchase	144,606	138,640	138,750	421,996
	Sub-Total	\$ 396,804	\$ 386,677	\$ 415,086	\$ 1,198,567
	Distribution Substation Modernization				
166	Tap Changer Position Indicator System	132	-	-	132
168	Temperature Gauges	100	100	100	300
169	USS Transformer Replacement	600	600	600	1,800
170	4kV USS Switchgear Replacement	2,200	1,200	1,200	4,600
171	USS Life Extension Program	1,170	1,361	1,361	3,892
172	Auto Reclose On Bank Breakers	250	250	250	750
	Sub-Total	\$ 4,452	\$ 3,511	\$ 3,511	\$ 11,474
	Overhead Enhancement				
173	C Truss Program	1,752	1,752	2,058	5,562
175	Autoloop Reliability	7,359	7,528	7,450	22,337
179	Aerial (Okonite) Cable Replacement	1,009	1,009	2,550	4,568
180	#4,#6 Self Supporting Wire	3,169	3,175	3,175	9,519
182	Overhead Feeder Sectionalizing Program	3,189	3,202	3,452	9,843
187	Automated Emergency Ties	750	750	750	2,250
188	Overhead Feeder Reliability	750	1,125	1,125	3,000
189	Rear-Lot Pole Elimination	1,437	1,437	1,437	4,311
191	4kV UG Reliability	1,111	1,111	1,111	3,333
194	Overhead Conductor Clearance	1,630	1,622	-	3,252
196	Overhead Secondary Reliability Program	500	500	500	1,500
197	Targeted Primary DBC Replacement	-	-	800	800
198	URD Cable Rejuvenation/Fault Indicator	806	198	198	1,202
200	ATS Installation USS Reliability XW	1,450	1,450	2,450	5,350
	Sub-Total	\$ 24,912	\$ 24,859	\$ 27,056	\$ 76,827

Project/Program Title	Hi-Pot
Status	Ongoing
Estimated Service Date	Ongoing
Work Plan Category	System and Component Performance

Work Description:

The Company's Hi-Pot program for feeders consists of two elements, the annual Spring Hi-Pot program and Modified Hipot program. Modified Hipots are performed on network feeders before they are returned to service following an Open-Auto (OA) event. Modified Hipots are prescribed at a lower voltage level than a spring Hipot and are intended to be a "proof of serviceability" test before the feeder is put back into service.

The Spring Hipot Program represents a proven diagnostic reliability tool for the mitigation of summer network primary feeder outages. This program is implemented annually from October 1 through May 31 and consists of three major stages: 1) the selection of targeted network feeders for the program; 2) the high voltage (DC or AC) testing of those feeders; and 3) the return to service of the feeders prior to the high capacity summer period.

In selecting the feeders for inclusion in the Spring Hipot program attention is paid to recent feeder summer performance, the composition of the feeder in terms of component type, and the relative importance of the feeder to network operation. Based on these characteristics a composite index of the likelihood of poor feeder performance and potential adverse network effects due to that performance is derived. Using this index, network feeders are prioritized and targeted for Hi-Pot testing.

The modified Hipot is intended to "fail on test" (FOT) any faulted feeder component not discovered during the initial feeder fault locating. This additional testing avoids the probability of closing the feeder breaker into another fault (known as Cut in open auto or CIOA) after the initial fault is repaired. Any network feeder may be subjected to a modified Hipot following an OA event.

Units per Year: 270 sections

Mandatory: Spec driven EO-4019 "Testing of AC Feeders Operating at 4kV to 33kV"

High-level schedule: Spring Hi-Pot complete by May 31 each year. Modified Hipots are performed as required

Justification:

The HiPot test procedure is described in detail in specification EO – 4019 "Testing of AC Feeders Operating at 4kV to 33kV" and essentially represents a high voltage test of targeted feeders with the intent of exposing incipient faults among the feeder components. It has been found that the compromised components detected through this testing are the same components that fail during the summer heat waves or as CIOAs. By detecting problem components under controlled conditions potential network feeder outages (both single and multiple) are avoided.

- Alternatives: The creation of backbone feeders (removing all PILC cable and associated splices from a feeder) to eliminate the failure prone stop-joints.
- Risk of No Action: System reliability will decrease as the failure prone stop-joints age and their failure rate increases. This will result in more summer feeder failures and CIOAs.

- Summary of Financial Benefits and Costs:

- Feeder Hipot program will increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs and regulator penalties are minimized.
- Feeder Hipot program will benefit Electric Operations in meeting annual key performance indicators, such as SAIFI and CAIDI interruption rates for the non-network system thereby avoiding potential regulator penalties.

- Non-financial Benefits (if applicable): None

- Technical Evaluation/Analysis:

Regression analysis performed across the previous eleven years of system summer outage data has shown that for approximately every nine FOTs obtained during the spring HiPot testing, one OA is avoided during the subsequent summer period.

Estimated Completion Date: Ongoing

Status: Ongoing

Funding: (\$000s)

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
3,232	2,124	4,069	4,221	3,549

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
3,400	5,498	5,600	6,100	6,100	26,698

Addendum

The company concurs with the proposed reduction in Hipot funding. This is a low priority program and the 38% reduction in FOT for 2010 through 2011 is expected to have little impact on system reliability.

Average Units per Year (FOTs) 2010 and 2011: 165 sections

Average Units per Year (FOTs) 2012 and 2013: 270 sections

The table below shows the proposed Hipot program funding levels through 2013.

Funding: (\$000s)

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
3,400	3,400	6,100	6,100	19,000

Project/Program Title	Paper Insulated Lead Cable (PILC)
Status	Ongoing
Estimated Service Date	December 2020
Work Plan Category	System and Component Performance

Work Description:

This program is designed to facilitate the removal of PILC cable from the primary distribution network feeders. This program, working with other PILC cable removal methods, will ensure the complete removal of PILC cable by the commitment data of year-end 2020. The other methods of PILC cable removal include: burn-outs, load relief and other reliability work.

Units per Year: About 1,700 sections per year through 2020

Mandatory: The PILC cable removals are a commitment made to the PSC

High-level schedule: On average, 2,400 sections must be removed each year to achieve the year-end 2020 goal.

Justification:

The program began in the mid 1980's due to concerns over the reliability and potential environmental impact of PLIC cable. Paper Insulated Lead Covered cable contains a dielectric fluid (usually a mineral oil) and a lead sheath that are potential environmental contaminants. Failure data collected during the 1980's also showed that older PILC cable was responsible for many feeder failures, especially during the summer months.

Reliability studies, following the 1999 Washington Heights network shutdown, determined that several distribution components, among them PILC cable and transition splices (stop-joint connecting PILC cable to the newer solid dielectric cable), had significantly elevated failure rates during summer heat waves. These studies also showed that the removal of these high failure rate components would result in major improvements in network reliability. Currently, transition splices remain the single biggest contributor to primary feeder failures during summer heat-wave periods. The PILC cable, while less of a reliability issue than the transition splices, still has a failure rate, on the Con Edison system, that is an order of magnitude higher than the newer solid dielectric cable (principally Ethylene Propylene Rubber, EPR, cable). The only practical method to remove these heat sensitive transition splices is through the removal of the attached PILC cable.

The primary distribution network feeders are currently comprised of approximately 17 percent PILC cable. This equates to about 23,000 cable sections. To complete the removals by the commitment date of year-end 2020 approximately 2,100 sections, on average, would need to be removed each year for the duration of the program. The PLIC Cable Replacement program would remove over 80 percent of the cable, with the other 20 percent the result of burn-outs, load relief and other reliability work. Since 1999 an average of 2,400 primary feeder PILC cable sections has been removed from the networks each year.

Recent reliability studies have shown that the removal of PILC cable, and the associated transition splices, results in significant improvements to the Network Reliability Index (NRI).

- **Alternatives:** An alternative to the PILC Cable Replacement program would be to leave the PILC cable and replace the high failure rate transition splices a newer, more reliable, splice design. This would reduce the cost of the program by one-third but would not have the same impact on reliability as removing both the cable and the transition splice. We have developed a better transition splice but replacing the nearly 10,000 in-service transition splices would take the same amount of time and still result in a less reliable system.

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- Risk of No Action: Reliability studies have shown that the NRI would significantly decrease, noting network degradation, over time if the PILC cable and transition splices were left in operation.
- Summary of Financial Benefits and Costs: The removal of the 1,700 sections of PILC cable, at a cost of \$32 million dollars, will result in a reduction of 4 summer OAs (\$8 million per OA). The removal of 1,700 sections per year will also eliminate about 3,400 transition splices for a reduction of about 34 summer OAs.
- Technical Evaluation/Analysis: An NRI analysis could be performed, if requested, to show the benefits to network reliability due to the elimination of PILC cable and associated transition splices.

Estimated Completion Date:

Status: Ongoing through 2020.

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
3,979	21,969	23,818	19,743	32,376

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
32,035	33,000	33,000	33,000	33,000	164,035

Addendum

The table below shows the proposed funding levels for 2010 through 2013.

The company concurs with the proposed funding reductions in the PILC cable program. These reductions will have little impact on the 2020 commitment date for the complete removal of PILC cable or system reliability.

The proposed reductions in the PILC cable program for years 2010 and 2011 will result in the removal of a projected 328 fewer cable sections in those years. This reduction, taken with the 2009 reduction, will necessarily extend the commitment date for the elimination of PILC cable from distribution feeders to, at least, 2021. This potentially could result in only two additional PILC cable section failures by the summer of 2012.

The program reductions will also leave approximately 100 high failure rate transition splices, associated with the 328 section of PILC cable, on the system. This potentially could result in only one additional transition splice failure by the summer of 2012.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
27,085	27,085	33,000	33,000	120,170

Project/Program Title	UG Sectionalizing Switches
Priority Number	
Project Manager	Elie Chebli
Project Engineer	Regional Engineering Managers
Budget Reference	5ED1181; 5ED3171
Project Number	
Status	Planning
Estimated Service Date	2013
Work Plan Category	System and Component Performance
ERM Addressed	Network Shutdown

Work Description:

Install primary underground sectionalizing switches on targeted network feeders. The Company has recently initiated the installation of the new Elastimold Three Phase Molded Vacuum 40kA switch that replaces the old motor operated three phase SF6(sulfur hexafluoride) gas insulated switch. The new switch does not require a manual operation and is SCADA ready for remote operation. 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, installing the switch with cam disconnects, fault indicators, and associated cabling.

Units per Year: 27

Mandatory: The program is not mandated by the PSC but is critical to Company's most cost effective long term network distribution system reliability.

High-level schedule:

Year	Manhattan	Brooklyn/Queens	Bronx/Westchester	Total
2010	4	11	12	27
2011	4	11	12	27
2012	4	11	12	27

Justification:

Installation of primary sectionalizing switches to isolate feeder failures increases network reliability. The sectionalizing switches permit rapid isolation of faulted segments of primary feeders, allowing the portion that is not faulted to be re-energized, and thereby reducing the amount of load shifted to other distribution feeders. This will in turn reduce the failure rates for adjacent feeders that pick up the load of the faulted feeder section, as the loading of the components has an impact on their failure rates.

The benefits of installing sectionalizing switches have been documented through the "Contingency" network reliability model. The analysis concluded that the reduction in time between the manual switch operation of four hours compared to the remote switch operation in 5 minutes significantly reduces the increase in temperature of feeder components, and thereby reduces the probability of subsequent component failure. Feeder restoration time plays an

important role in network reliability and with the more feeders are out of service, the higher is the probability of a network going into cascading events. The feeders in a network are targeted for sectionalizing switch installation based on their individual contribution to network reliability and with existing bifurcated feeder legs.

The new switches are fitted with SCADA equipment for remote monitoring and operation. The new switches will be integrated into the Distribution Automation System (DAS/RealFlex) system that uses the 900MHz licensed frequency “company owned,” and eliminate any communication expense.

The new cam disconnects are easy to operate, provide more security and safety and are more reliable than the existing H-type disconnects.

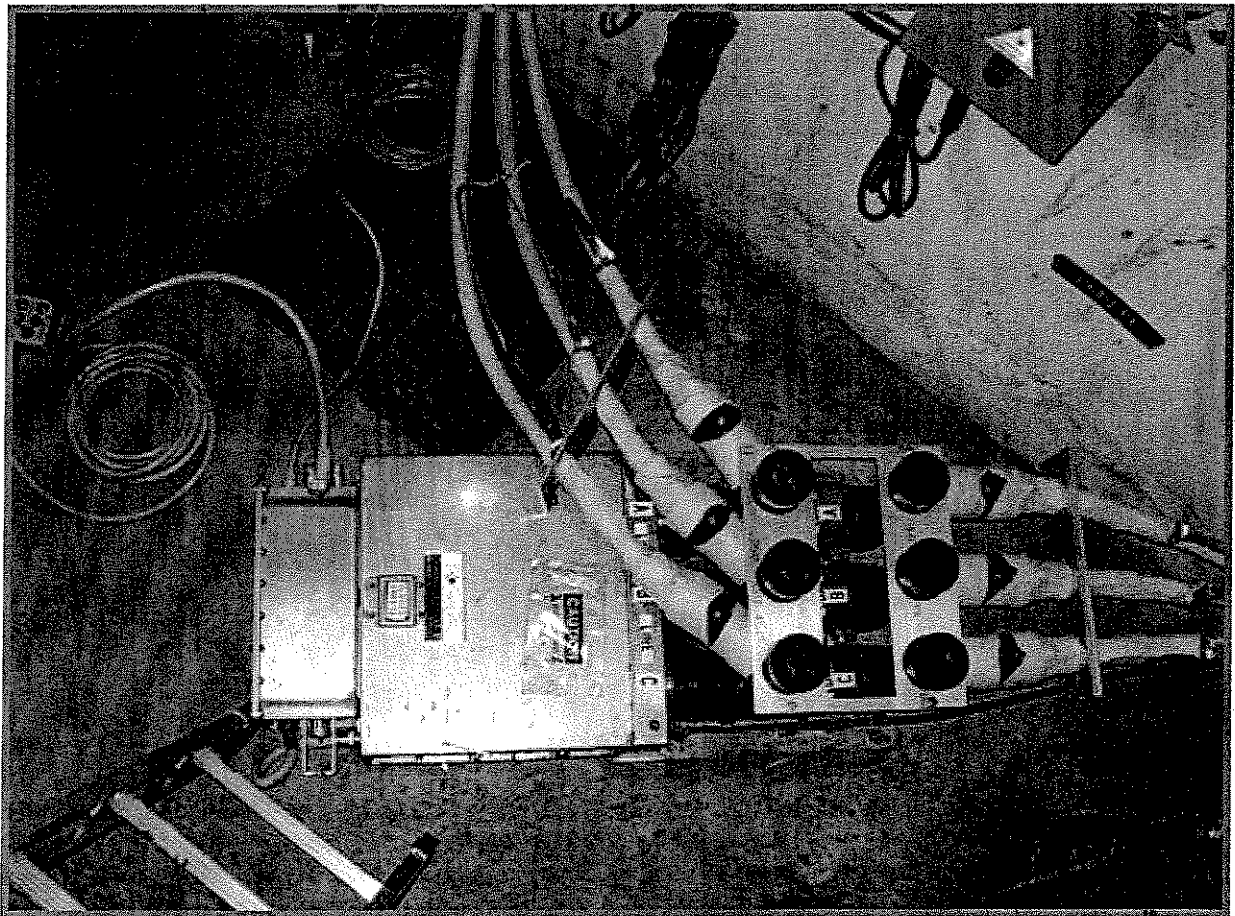


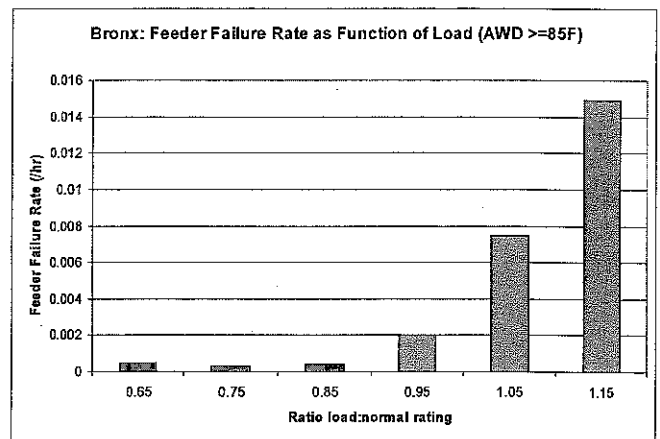
Figure 1 – New Elastimold Three Phase Molded Vacuum 40kA switch

- Alternatives: Network Reliability Program is the alternate to the UG Sectionalizing program but is only applicable if there are spare feeder positions available at the Area Substation. This program includes de-bifurcating an existing feeder to create two new feeders utilizing existing spare feeder positions at Area Substations. To accomplish this, bifurcated feeders supplying a given network or load area via two main runs of cables (legs) will be de-bifurcated, creating two separate feeders with one leg each. These additional feeders will provide a more

distributed and balanced supply to the network and more balanced feeder loading during normal conditions (all feeders in service). The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

Network Reliability is not always a viable alternative as it is dependent on spare feeder positions at the Area Substation. Manhattan has selected a staged approach to improve the Yorkville network reliability by installing four new sectionalizing switches annually in the Yorkville network as there are no vacant cubicles available at the Hellgate S/S and it is not cost effective to build additional feeder positions.

- Risk of No Action: Feeder loading has an effect on feeder reliability and installation of sectionalizing switches mitigates increased feeder loadings on existing feeders through partial restoration of the section that is not faulted. Feeder load increases with temperature rise and very high loads, as compared to the normal rating, have an adverse effect on feeder components. As can be seen from Fig 2, feeder OA events in heat waves (AWD greater than 85 F), increase dramatically when the loading exceeds 95% of the normal feeder rating.



The risk of no action increases the risk of distribution networks will be significant during contingency events.

- Summary of Financial Benefits and Costs: The new remotely operated switches significantly reduce the annual O&M switch maintenance costs associated with the mandatory operation of the switch once every 6 months. The SCADA equipment installed on the switch has remote diagnostics capability and only requires a field visit for repairs if it fails, thereby resulting in additional O&M savings. There is no recurring communication expense associated with the remote operation of the switches.
- Non-financial Benefits (if applicable): Elastimold 40 kA Molded Vacuum Switch is more environmentally friendly as compared to SF6 Switch as there is no risk of gas leaks. In addition, the Vacuum switch has the same rating as SF6 switch and is more compact with cam-op disconnects to provide visible breaks that meet the Con Edison work rules for worker safety and protection. The new switch requires minimal maintenance and operates faster (in approximately 2.5 cycles) compared to the old SF6 switch that can take a few seconds to operate due to the motor operation.
- Technical Evaluation/Analysis: The switch is rated for 27 kV, and it can be installed on 13 kV or 27 kV feeders. The maximum available fault current at the location for the switch cannot exceed 40 kA, RMS symmetrical and 64 kA RMS asymmetrical. The continuous current for the switch is rated for 600 amperes. The switch should not be operated more than 600 amperes.

- Sensitivity Analysis (if applicable):
- Project Relationships (if applicable):

Estimated Completion Date: 2013

Status: Planning

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	1,357	2,077	2,057	1,662

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
4,062	4,356	4,475	4,501	4,501	21,895

Addendum

The Company concurs with Staff's recommended reductions to the Program by \$794,000 in 2010 and \$913,000 in 2011. As a result of these reductions, the Company will reduce the scope of work by two switches annually in 2010 and 2011. The Company will prioritize switch installations in networks with highest network reliability index (NRI) ranking. The updated breakdown of the number of switches by Region is listed below.

Year	Manhattan	Brooklyn/Queens	Bronx/Westchester	Total
2010	4	10	11	25
2011	4	10	11	25
2012	4	11	12	27

As a result of this reduction, the Company will defer four sectionalizing switch installations beyond 2012.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 200-2013
3,562	3,562	4,501	4,501	16,126

Project/Program Title	Network Reliability
Status	Ongoing
Estimated Service Date	2015
Work Plan Category	System and Component Performance

Work Description:

Establish new distribution feeders by de-bifurcating existing feeders. To accomplish this, bifurcated feeders supplying a given network or load area via two main runs of cables (legs) will be de-bifurcated, creating two separate feeders with one leg each. The Company will utilize existing spare feeder position in area substations, or construct new area substation cubicles where necessary, to accommodate the new distribution feeders.

Units per Year: 5 to 6 new feeders per year

Mandatory: This program is suggested to meet the corporate goal of increasing the network reliability for each network to a Network Reliability Index one into one thousand years.

High-level schedule: Three to four feeders per year will be established between 2010-2015.

Justification:

The reliability of the networks and load areas where these new feeders will be established is expected to improve. Since 1999, Con Edison has worked to identify the factors that affect the reliability of network feeders and the likelihood of multiple network contingencies. For heat waves, feeder and component load and the occurrence of feeder open-autos (OAs) within a short time of a previous OA are found to be particularly important.

These additional feeders will provide a more distributed and balanced supply to the network and more balanced feeder loading during normal conditions (all feeders in service). The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

Additionally, this program will reduce the number of components (i.e. cable, splices, and transformers) per feeder, thereby reducing exposure to failures and improving reliability.

- **Alternatives:**

Alternatives for increasing network reliability are installing sectionalizing switches, known point splices, and replacing PILC cable. None of these alternatives are as effective (measured by the NRI model) for increasing reliability as establishing a new feeder.

- **Risk of No Action:**

Network outages due to cascading feeder failures associated with high feeder loading due to shifting load following a feeder open-auto.

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- Summary of Financial Benefits and Costs:

Establishing new feeders increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs, and regulator penalties are minimized.

Balanced load on the bifurcated feeders may reduce some future load relief costs on the associated feeders.

- Non-financial Benefits (if applicable):

Increase reliability as measured by NRI (Network Reliability Index), SAIFI and CAIDI.

- Technical Evaluation/Analysis:

Networks and feeders have been modeled using the Network Reliability Index model to determine the priority and effectiveness of establishing new feeders in each area.

Estimated Completion Date:

2015

Status:

Ongoing

Funding: (\$000s)

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	4,963

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
16,300	25,723	26,545	26,545	26,545	121,658

Addendum

The Network Reliability Program reduction to \$21.5 million for 2010 will not change the feeders to be established for 2010 but it will delay the procurement of equipment and cubicle construction for new feeders to be established in 2011. This may delay the in service date from June 2010 to the end of year. Cutting the 2011 budget to the same levels will allow us to establish the required 9 new cubicles but will delay the construction of some distribution feeders. This will push the in service date from December 2011 to June 2012.

Funding: (\$000s)

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
21,323	22,145	26,545	26,545	96,558

Project/Program Title	Coastal Storm Mitigation
Status	Ongoing
Estimated Service Date	Ongoing
Work Plan Category	System and Component Performance

Work Description:

This program was initiated as part of Con Edison's Corporate Coastal Storm Plan ("CCSP"). An analysis of equipment during the development of the Company's Coastal Storm Plan identified underground equipment in the various storm surge zones associated with each level of hurricane as established by the Army Corp of Engineers. Because of the potential exposure to storm surge and our need to provide service to our customers within these areas, we have established this program to mitigate the impact of salt water exposure.

Focusing on the network equipment residing in the Category 1 hurricane storm surge area, this program addresses two key issues. First, it provides for the electric isolation of 277/480V locations where we do not presently have an opportunity to replace existing equipment with submersible equipment. Second, it identifies and establishes a program to replace existing non-submersible 120/208V equipment with submersible equipment.

During a significant coastal storm, the Company's service area may be impacted by storm surge. This storm surge, as predicted by the Army Corps of Engineers, will expose certain underground equipment to salt water. Some of our underground equipment within the anticipated storm surge area is not designed to be exposed to salt water. The exposure of this non-submersible equipment when energized may cause it to fail, thereby risking the integrity of the distribution feeder and the associated network. In addition, the exposure of this non-submersible equipment when de-energized would also result in significant damage to exposed parts such as relays and motors. The repair or replacement of these exposed de-energized units would increase the time required to restore our system after a significant coastal storm.

The Company will install flood switches to isolate approximately 305 transformer vault locations containing 277/480V equipment in Category 1 storm surge zones. (As noted by Company witness Kressner in the 2008 electric rate case, these flood switches were developed as part of a Company Research and Development effort.) The switches allow the transformer to be de-energized without the need to de-energize its supply feeder. Once installed, these flood switches will facilitate isolating portions of the system in anticipation of a significant coastal storm event.

Further, the Company will replace approximately 140 120/208 transformer vaults with vaults that can accommodate submersible transformers and network protectors. Existing vaults are not large enough to accommodate the size of the submersible transformers and network protectors currently available to the Company. The installation of submersible transformers and network protectors in these enlarged vaults will minimize the damage that will result when these vaults and the associated equipment are exposed to salt water.

In an effort to reduce costs and expedite the replacement of the non-submersible equipment, Con Edison also is working with vendors to develop a prototype submersible transformer and network protector that fits into existing vaults. This would enhance our ability to change these units out since it would eliminate the time, effort and cost associated with replacing the entire vault structure. Pending development of a viable prototype, our existing plan cost study anticipates replacing the existing vault structure. This design work is presently underway by Distribution Engineering.

The use of the flood switch and the replacement of non-submersible equipment will contribute to minimizing the damage realized during a significant storm surge event. Based upon preliminary design

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requirements associated with the replacement of these units, a Replacement Task Force will be required to project manage the program. This is in addition to the 14 field personnel required for the completion of this work. Based on this funding level we anticipate that the locations identified in the category 1 zone would be completed in approximately 31 years.

<u>Units per Year:</u>	10 Switches/5 Vaults
<u>Mandatory:</u>	Mandatory
<u>High-level schedule:</u>	Continuous

Justification:

In the event of a storm surge, non-submersible transformers and associated network protectors in the flood zone would be damaged by seawater. As this equipment fails, distribution feeders will open automatically and may place a given network or load area in a contingency situation. The recovery effort after the storm event would be extensive to repair and replace the damaged equipment in both time and cost. Submersible equipment will prevent some of the equipment failures and will enhance the reliability of the networks and load areas by minimizing the damage and the recovery effort.

- Alternatives: There are no feasible alternatives that take the place of upgrading non-submersible equipment or installing disconnect switches to remove the non-submersible equipment from service.

Con Edison could convert its electric distribution system in the storm zones to an overhead system, but this would be cost prohibitive and unacceptable to the local community boards.

- Risk of No Action: In the case of a coastal storm, flooded networks will be at risk of being shutdown if several feeders in the network supply non-submersible equipment.
- Summary of Financial Benefits and Costs: The coastal storm risk mitigation program increases network reliability and reduce the risk of network shut down in the case of a large coastal storm. Costs associated with network shutdowns such as restoration costs, and regulator penalties are minimized.
- Technical Evaluation/Analysis: The coastal storm risk mitigation projects will be prioritized according to risk level, and then by network and feeder. All Category 1 storm risks will be addressed before moving on to Category 2 storm risk.

In a network, a feeder will be considered complete only when all of the submersible equipment for a storm level has been addressed. If one non-submersible structure in a flood zone is left unaddressed, the feeder will open auto in spite of the other structures addressed on the feeder.

Estimated Completion Date: 2040

Status: Design for submersible network protectors is pending.

Funding: (\$000s)

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	74

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
2,446	3,000	3,000	3,000	3,000	14,446

Addendum

The Company will replace approximately 140 120/208 locations with transformers and network protectors that are submersible. Existing vaults contain non-submersible equipment that would be adversely effected by storm surge. The installation of submersible transformers and network protectors in these locations will minimize the damage that will result when these vaults and the associated equipment are exposed to salt water. The Company anticipates the availability of the newly designed network protectors will significantly lower the cost of this program and allow for the completion by the target date for this program.

<u>Units per Year:</u>	4 Switches/2 Vaults
<u>Mandatory:</u>	Mandatory
<u>High-level schedule:</u>	Continuous

Funding: (\$000s)

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
1,000	1,000	3,000	3,000	8,000

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Project/Program Title	C Truss Program
Status	Ongoing
Estimated Service Date	Ongoing
Work Plan Category	System and Component Performance

Work Description:

Accelerate capital installation of C-trusses and pole replacements to address significant backlogs. The target of 378 C-truss units and an additional 130 Poles will need to be installed in years 2010-2013 to reduce the backlogs to zero in ten years.

O&M - Inspection and Treatment involves sounding the pole, taking bore samples, installing MITC Fume carterages, treating the pole with an osmoplastic wrap and chemical paste or a combination of these processes. Poles are identified as either Good or Reject. Good Poles are treated dependent on the situation and field conditions. Reject Poles fall are categorized as either a Priority Pole, Non-Reinforcable Pole, or a Reinforcable Pole. This work is performed by contractors.

Capital - C-Trussing or Pole Replacement - Reinforcable Poles can be brought back within NESC guidelines when their bases have deteriorated beyond acceptable levels by installing a C-truss. C-trussing reinforces the base of the pole by installing a metal "C" shaped truss along its side. This work is performed by contractors.

Years	Annual Units Completed		Accelerated 10-Year Zero Backlog Units				Average Annual Dollars (\$000)		Accelerated Additional Dollars (\$000)		Total New Osmos Funding Reques (\$000)	
	C-Truss	Pole Replace	C-Truss	Pole Replace	Total C-Truss	Total Pole	Capital	O&M *	Capital	O&M *	Capital	O&M *
2009	1,225	193	-	-	1,225	193	\$ 1,746	\$ 1,052	-	-	1,746	1,052
2010	1,225	193	-	130	1,225	323	\$ 1,768	\$ 1,052	290	133	2,058	1,185
2011	1,225	193	-	130	1,225	323	\$ 1,768	\$ 1,052	290	133	2,058	1,185
2012	1,225	193	-	130	1,225	323	\$ 1,768	\$ 1,052	290	133	2,058	1,185
2013	1,225	193	-	130	1,225	323	\$ 1,768	\$ 1,052	290	133	2,058	1,185
							\$ 8,818	\$ 5,260	\$ 1,160	\$ 336	\$ 9,978	\$ 5,596

* Inspection, treatment and MAC

Replacing Reject poles carries both a Capital and O&M/Maintenance Associated with Capital (MAC) cost. Poles categorized as Priority or Non-Reinforcable are replaced (capital) and equipment is transferred (MAC) from the old pole. This is performed by company Overhead Line Construction crews.

Justification:

Pole inspections should be performed to ensure the reliability of installed poles and safety of the public as referenced in the U.S. Department of Agriculture Bulletin 1730B-121, *Pole Inspection & Maintenance*, Utilities in

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Decay Severity Zone 2 (New York Area). A majority of the poles are inspected and treated as part of a maintenance program. Inspected poles requiring attention are either replaced or restored to full strength and functionality by way of C-Trussing therefore deferring the need to replace the poles and at a reduced cost when compared to replacement. Due to increasing loads on wood poles primarily due to larger conductor sizes and third party attachments and to ensure public safety, it is necessary to either extend the life of the pole via C-trussing or replace the pole. Accelerating the program, which has been under-funded in the past, will allow for a substantial reduction to the backlog of defective poles.

- Alternatives: Premature failure of poles
- Risk of No Action: Threat to public and employee safety
- Project Relationships (if applicable): MAC

Estimated Completion Date: Ongoing

Status: Ongoing

Funding (\$000):

Capital

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	734	972	1,443

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
1,746	2,058	2,058	2,058	2,058	9,978

O&M – Inspection, Treatment and MAC

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
581	525	955	852	1,185

Approved 2009	Forecast 2011	Forecast 2012	Forecast 2013	Forecast Total 2011-2013
1,185	1,185	1,185	1,185	4,740

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Addendum

The reductions for the future years returns the replacements back to historical levels.

Funding (\$000):

Capital

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
1,752	1,752	2,058	2,058	7,620

Years	Annual Units Completed		Accelerated 10-Year Zero Backlog Units		Original Dollars Requested (\$000)	Total Revised Funding Request (\$000)
	C-Truss	Pole Replace	C-Truss	Pole Replace	Capital	Capital
2009	1,225	193	-	-	\$ 1,746	\$1,746
2010	1,225	193	-	-	\$ 2,058	\$1,752
2011	1,225	193	-	-	\$ 2,058	\$1,752
2012	1,225	193	-	-	\$ 2,058	\$1,752
2013	1,225	193	-	-	\$ 2,058	\$1,752
					\$ 9,978	\$ 8,754

Project/Program Title	Aerial (Okonite) Cable Replacement
Status	Ongoing
Estimated Service Date	2013
Work Plan Category	System and Component Performance

Work Description:

Continue the program to replace high failure rate aerial cable on the non-network distribution systems to increase overall system performance and reliability. Replacing existing cable such as Okonite with new primary cable will reduce the frequency of customer interruptions (SAIFI) due to aerial cable failures.

Justification:

Replacing aerial cable with high failure rates will improve system reliability. The aerial cable in this program supplies first contingency non-network loads including 13kV loops and 4kV unit substations. These feeders also serve sensitive loads such as hospitals, nursing homes and corporate headquarters. Frequent failures of this cable place loops and unit substation customers in frequent contingency operation resulting in unacceptable customer interruptions. A review of our feeder performance over the last five years indicates that we experienced on average 18 failures per year on aerial cable. While the average number of failures remains relatively constant, since 2004, we have expended our aerial cable maintenance budget by an average of \$950,000 per year as the replacement of sections of aerial cable for these failures has become more extensive. The outer jacket on this older aerial cable has in many cases become porous over the years, causing the cable to absorb water. When a failure does occur, it is sometimes necessary to replace as much as 3,000 to 5,000 feet of cable in order to find dry cable to splice, thereby resulting in lengthy feeder outages. Proactive replacement of this troublesome cable with our standard Aerial Cable, (3-1c500 kcmil copper with EPR insulation, Con Edison specification 7558E), will increase reliability and decrease the frequency customer outages caused by aerial cable failures and the duration of feeder outages following a cable failure. Replacement priority will be determined by the failure history of the various sections of cable.

Alternatives:

Replacing existing aerial cable with 3-1c500 kcmil copper with EPR insulation when ever there is a failure would be an option. However, that practice would cause thousands of customers to be out of service for an unspecified period of time.

Estimated Completion Date: Ongoing

Status: Continuation of Existing Program

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	758	823	44	539

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
3,021	2,532	2,544	2,550	2,550	13,197

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Addendum

Due to the reduced funding level of \$1,009,000 in 2010 and 2011 the Company will only be able to replace approximately 89 spans a year in those 2 years. This is about 126 units less than requested in each year.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
1,009	1,009	2,550	2,550	7,118

Project/Program Title	Targeted Primary DBC Replacement
Status	Ongoing
Estimated Service Date	2029
Work Plan Category	System and Component Performance

Work Description:

This is a 20 year program that targets primary and secondary Direct Buried Cable (DBC) cables to be replaced with cable-in-conduit (CIC) to improve the reliability of Underground Residential Distribution (URD) customers and to reduce burnout expenditures incurred to repair DBC cables. Candidate cables for replacement usually experienced two or more failures at different spots along the cable section where often the insulation is found to be cracked or split. These candidate cables for replacement will be prioritized appropriately to address the highest urgency replacements.

Justification:

During the past 3 years, approximately 60% of all URD customer interruptions were due to insulation breakdown of DBC primary and secondary cables. These interruptions result in an increase in SAIFI by an average of 22 outages/year and 46 outages/year for Westchester and Staten Island, respectively. On average, it takes 20% longer to locate and repair a fault when it occurs on DBC than it does to repair a fault that occurs on the same cable installed in a conduit. From 2002 to 2007, an average of 1,250 URD customers each year in Westchester and Staten Island (98% of all URD customers) experienced a service interruption due to problems with DBC. 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.

Alternatives: URD Cable Rejuvenation Rehabilitation and Fault Indicator Program

Risk of No Action: Continued customer interruptions due to URD cable failure

Non-financial Benefits: Improve system performance by reducing customer interruptions. Increase reliability and reduce SAIFI

Estimated Completion Date : 2029

Status: Ongoing

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	11,183	5,810	2,468	2,409

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
504	800	800	800	800	3,704

Addendum

Due to elimination of funding in 2010 and 2011 the Company will have to defer the replacement of 38 sections (19 per year) of URD cable. The net result will be an extension of the current completion date from 2029 to 2031.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
0	0	800	800	1,600

Project/Program Title	ATS Installation / USS Reliability
Status	Ongoing
Estimated Service Date	2018
Work Plan Category	System and Component Performance

Work Description:

This program will install new Automatic Transfer Switches (ATS) switches at 53 unit substations at an estimate cost of \$450K per location.

Units per Year: We plan to install 5-6 ATS units each year.

The table below lists the unit substations in the program and the priorities for each 4kv grid:

1-Zerega Ave	2-Middletown Rd	3-Screvin #1	4-Screvin #2	5-Sampson #1
6-Sampson #2	7-Sommer #1	8-Sommer #2	1-Chester Heights	2-Valley-Pl
3-Quaker Ridge	4-Beechwood	5-Osman Pl	6-Palmer #1	7-Gun Hill
9-E.226St	8-Forest	10-Webster	11-Flint Park	12-Bonnie Briar
13-Eastchester Creek	1-Woodlawn-55	2-Yonkers	3-Whrexham	4-Grassy Sprain
5-Lawrence Park	1-Mt Hope	2-Crestwood	3-Fort Hill	4-Canfield
5-Helena	1-Rockne	2-Nepperhan	3-Rose Hill	1-Fenimore
2-Kenilworth	3-Gedney	4-Haviland	5-Underhill	6-Scarsdale
7-Saxon Woods	8-Heathcote	9-Green Knolls	10-Vernon Hills	11-Primrose
1-Milton Point	2-Manursing	3-Bowman	1-Van Wart	2-Manhattan Pk-3
1-Maryknoll	2-Thornwood-32	1-Furnace Dock		

Justification:

Automatic Transfer Switches (ATS) switch a unit substation to an alternate 13kV supply automatically when the primary supply is lost. ATS' are 'smart' automation elements that enable our system to automatically reconfigure itself upon the loss of a preferred source, ensuring a first contingency design. Adding ATS installations at the designated substations allows us to maintain our single contingency design criteria. Of the 112 unit substations in the Bronx / Westchester region, 35 are currently equipped with ATS units. This program will add ATS switches to the 50 highest priority stations that do not have this functionality.

During the summer period, loss of primary supply to a unit substation, prompts the immediate dispatch of a 2MW generator as a proactive measure to relieve 4kv feeders in anticipation of a next feeder or station outage. In addition, overhead switching moves are provided to inter-tie feeders to improve customer voltage. The dispatch and interconnection of a generator is an expensive and time consuming task. The average time to transport, setup and connect a generator is 6 hours. Until the generator and associated switching are complete the 4kV grid is exposed to a heightened risk of a cascading outage. While generators can significantly reduce or eliminate the risk of cascade, their use is generally undesirable because they generate complaints from customers and officials regarding noise and/or traffic inconveniences. The proposed ATS installations are prioritized by the potential impact each substation will have on the reliability should the station lose its source of supply. History indicates that each year 1 to 2 grid outages could have been eliminated had the unit substation been equipped with an ATS switch.

- Alternatives: Reduce the number of customers to be restored during outages on the 4kv system by converting portions of the 4kv system into 13kv auto loop systems. In addition, to maintain the remainder of the 4kv system reliable, the cable ties to other units must remain. Adding the 13kv system will overcrowd the streets with two systems. This alternative plan was rejected due to prohibitive costs.

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- Risk of No Action: Each year there are least 1-2 outage events on any 4kv grid due to the lack of ATS, causing from few hundred to several thousands of customers to be without power. With no action, we cannot improve SAIFI and CAIDI benchmarks.
- Non-financial Benefits (if applicable): This program provides enhanced reliability to the customers and better enables the Company to live up to its mandate to provide safe and reliable service to its customers by allowing for additional supply feeders to 4kV grids.

Estimated Completion Date: 10 years to be completed by 2018. We plan to install 5-6 ATS units each year at a cost of \$450K/unit.

Status: Ongoing program. In the past we have installed ATS at unit substations as a reactionary move to remedy the repeated outages caused by the failure of multiple primary supply feeders including the high 4kv feeder loads. We do not have a specific program on ATS installations to improve the reliability of the 4kv grid, and thus this program has been initiated in 2009.

Funding: (\$000s): Capital

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	150

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
2,450	2,450	2,450	2,450	2,450	12,250

Addendum

Due to the reduced funding level of \$1,450,000 in 2010 and 2011 the Company will only be able to install 3 new ATS installations in 2010 and an additional 3 in 2011 instead of 5-6 per year which the program called for. The net result of this reduction will be extending this program by an additional year to 2019 at the expected installation rate of 5-6 units per year at a cost of \$450k/unit.

Funding: (\$000s): Capital

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
1,450	1,450	2,450	2,450	7,800

System & Transmission Operations Operation and Maintenance Summary (\$000)									
Page	Work Plan Category	Project / Program Description	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Year Forecast (A+B)	Program Changes	April 1, 2011 to March 31, 2012 Rate Year Forecast	April 1, 2012 to March 31, 2013 Rate Year Forecast
	Environmental		829	1,273	1,971	2,800	(1,650)	1,150	-
16		Corrosion Repairs	451	657	99	550	-	550	-
18		Manhole Cleaning	353	541	97	450	-	450	-
20		Furnace Brook Lake Dam Maintenance	25	75	1,775	1,800	(1,650)	150	-
		Sub-total	829	1,273	1,971	2,800	(1,650)	1,150	-
	Public and Employee Safety		928	945	197	1,125	-	1,125	-
22		Manhole Inspections	817	700	133	950	-	950	-
24		Partial Discharge / Rainey Tunnel Inspections	111	245	84	175	-	175	-
		Sub-total	928	945	197	1,125	-	1,125	-

Project/Program Title	Furnace Brook Lake Dam Maintenance
Status	On-going
Estimated Service Date	On-going
Work Plan Category	Environmental

Work Description:

The work scope for this program includes the initial inspection and maintenance of an earthen dam located in the Town of Cortlandt, NY as well as the planning and construction costs associated with decommissioning the dam. Maintenance will depend on the results of periodic inspections by Engineering or engineering consultants, and will consist of vegetation management activities, routine earth work, spill way modifications, and decommissioning activities. Inspection criteria will be developed by Engineering and/or the consultants during the 2009 calendar year as approved in the previous rate case submittal. The company will be working with our consultant, the Department of Environmental Conservation, (NYSDEC) and the Town of Cortlandt to expedite decommissioning the dam or declassification efforts. The cost estimate for the major construction work to complete this work is shown in rate year ending 2012.

Units per Year: 1 inspection per year, project planning and decommissioning/declassification in rate year 2011.

Mandatory: Yes for annual inspections and maintenance but no for the dam decommissioning work. Decommissioning is the best economic solution for the company since it eliminates future inspections and maintenance activities reduces current liabilities and would no longer require NYSDEC reporting.

High-level schedule:

RYE 2010: General site planning work, environmental assessment work, and dam decommissioning planning activities.

RYE 2011: Dam decommissioning/declassification construction activities, continued work with the community board and implementation of a mitigation plan for the site;

RYE 2012: Final inspection and maintenance work before permit closeout.

Justification:

Repair work was performed on the Furnace Brook Lake Dam in early 2007. The funding being requested in this rate case will be used for engineering evaluations of the dam, maintenance recommended as a result of NYSDEC mandated inspections, and construction activities to decommission/declassify the dam. Proper maintenance is essential to dam integrity and inspection and repair of the dam is required under NYSDEC regulations. The work is required to maintain compliance with NYSDEC dam regulations.

- Alternatives: Do not decommission the dam and continue implementing an inspection program that consists of the following:
 1. An annual certification which includes an Emergency Action Plan (EAP) and Operation and Maintenance plan;
 2. An incident report every five years;
 3. A safety inspection every two years;
 4. Financial security annually; and
 5. An engineering assessment every 10-years.

This alternative is costly at an estimated annual cost of \$70k per year after initial expenditures of \$1,200k to bring the dam into compliance.

- Risk of No Action: If no action were taken in this program, a significant liability would remain, the company would not be in compliance with NYSDEC regulations, and there would be additional environmental and safety risks for the public.
- Summary of Financial Benefits and Costs: Decommissioning saves on long term consultant costs, inspection costs and general maintenance costs associated with annual NYSDEC certifications. The cost shown in rate year 2011 includes the consultant work (\$125k), field surveying and engineering design (\$400k), and field construction costs (\$1,475,000). In 2012, final inspection, permit closeout and site mitigation work will be completed (\$150k.)
- Non-financial Benefits: The major non-financial benefit associated with this program is public safety and a reduction in company liabilities related to trespassing concerns.
- Technical Evaluation/Analysis: Consultant work is currently in progress. Decommissioning work scope is being developed which includes an environmental assessment, planning work, and general construction requirements. The final design is expected to be completed and implemented in the 2011 rate year.

Estimated Completion Date:
RYE 2012

Status:
On-going

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
0	43	4	273	25

Approved 2009	RYE 2011	RYE 2012	RYE 2013	Forecast Total 2011 – 2013
75	2,000	150	0	2,150

Addendum

Funding (\$000):

RYE 2011	RYE 2012	RYE 2013	Forecast Total 2011 – 2013
1,800	150	150	2,100

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		Rate Case Submission			
Page	DESCRIPTION	2010	2011	2012	3 Year Total 2009-2011
	Public Safety	\$ 21,243	\$ 27,079	\$ 29,416	\$ 77,738
27	Vented Service Box Covers	11,875	15,375	15,375	42,625
29	Isolation Transformers	5,809	8,145	10,482	24,436
31	Pressure, Temperature, and Oil Sensors	3,559	3,559	3,559	10,677
	Total	\$ 21,243	\$ 27,079	\$ 29,416	\$ 77,738
	Environmental	\$ 600	\$ 600	\$ -	\$ 1,200
33	Oil Minders	\$ 600	\$ 600	\$ -	\$ 1,200
	Total	\$ 600	\$ 600	\$ -	\$ 1,200

Project/Program Title	Vented Service Box Replacement Program
Status	Ongoing
Estimated Service Date	2017
Work Plan Category	Public Safety

Work Description:

The Scope of Work includes the installation of vented *metal* service box covers on the street and vented *composite* service box covers on the sidewalks. The program shall entail replacing all solid covers with vented composite covers on the sidewalk and a minimum of one cover panel at all service box locations on the street. There are ~172,000 service box locations pending replacement from 2008 to 2017. Many service box locations contain more than one vented cover resulting in a total of 191,500 covers. Based on 2008 history (Vented Manhole Program), the company found that some of the structures required re-grade. The material and labor cost associated with re-grade is significantly higher than regular installations.

Units per Year:

The original plan for the Service Box Program was to install 10,000 vented covers in 2008. However, the Company installed 8,868 service box vented covers between metallic and composite. The Company continued with the plan to install 11,400 vented service box covers for 2009. The Company will install 21,000 vented service box covers in 2010 and in the subsequent years until 2017 as originally planned. At the end of 2017, we will have completed approximately 191,500 vented service box covers.

Mandatory:

This program is not mandated by the Public Service Commission, however, 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, enhancing public safety, and mitigating stray voltage with the installation of vented composite service box covers on the sidewalks.

High-level schedule:

2008	2009	2010	2011	2012	2013
8,868	11,400	16,200	21,000	21,000	21,000

Justification:

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. Electrical Power Research Institute (EPRI) testing results indicate the success of vented covers in terms of reducing cover dislodgement. The installation of vented manhole covers has successfully validated the effect of ventilation in mitigating secondary events. In addition, smoke emitted through the ventilated cover creates a visible indicator and raises awareness for the public thereby increasing public safety.

The proposed 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. Compared to 2004, the underground structure events were reduced by 54% in 2008 and the Company related electric shock reports were reduced from 194 cases in 2004 to 11 cases in 2008, a reduction of 94%. Also, compared to 2007, when this program started, property damage was reduced by 50% in 2008.

Alternatives: This ongoing program was initiated to increase public safety and reduce property damage due to buildup of combustible gases associated with secondary events and mitigation of stray voltage. We are considering the possibility of using different technology and/or materials which is currently under

research and development stage. Current research shows that as of now the existing composite technology and materials used are the most effective choice.

Risk of No Action: There is a potential increase on the severity and volume of underground events and possible increase in stray voltage/energized metal covers on sidewalks if the Service Box Vented Cover and Composite Program is reduced or terminated.

Summary of Financial Benefits and Costs: It is difficult to scrutinize the financial benefits and costs because this ongoing program is core to public safety and reduction in property damage. The reliability of energy distribution has been increased by reducing associated secondary events. Through competitive bids the company has been able to reduce the expenditure for the Service Box Vented Cover Program. The average cost per installation in 2010 is \$732.

Non-financial Benefits: The Service Box Vented Cover Program will help to reduce the buildup of combustible gases associated with secondary events thereby reducing the severity of underground events and enhancing public safety. By mitigating stray voltage, with the installation of vented composite service box covers on the sidewalks, we limit the number of electric shock incidents each year.

Technical Evaluation/Analysis: EPRI testing results indicate the success of vented covers in terms of cover dislodgement. The installation of vented manhole and service box covers has successfully validated the effect of ventilation in mitigating secondary events. There were significant reduction in underground structure events, electric shock due to stray voltage, and property damage. The vented covers are designed using materials that withstand more than 80,000 lbs in compliance with the American Association of State Highway and Transportation Organization (AASHTO) Specification M306 Section 7 (Proof Load Testing). A conductivity test was performed on vented composite covers at a 100,000 kV and the voltmeter revealed a reading under 1V. Additional testing of exposure to extreme temperature at -40F and at 1200F resulted in no deformation, and a 2-hour continuous open flame test showed minor deformation but not structural damage.

Estimated Completion Date:

The Service Box Program started in 2008 and the projected completion date in year 2017 making it a ten year program.

Status:

The Service Box Program began in 2008 and as of December 31, 2008 currently there are 8,868 vented covers installed. The status of the program is current and under construction.

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
0	0	93	757	6,307

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
8,375	15,875	15,375	15,375	15,375	66,375

Addendum**Units per Year:**

The original plan for the Service Box Program was to install 10,000 vented covers in 2008. However, the Company installed 8,868 service box vented covers between metallic and composite. The Company revised the original plan based on the recommendation from staff (case 09-E-0428 August 2009). In the year 2010 the company will install 16,200 units and then increase to a full forecast of 21,000 units in year 2011 through 2013. From year 2011 and in the subsequent years until 2016 the company will install 21,000 units. In year 2017 the difference of 4,800 units from year 2010 will be picked up. At the end of 2017, we will have completed approximately 191,500 vented service box covers.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
11,875	15,375	15,375	15,375	58,000

Project/Program Title	Isolation Transformers (Formally Street Light Service Reliability)
Status	Ongoing
Estimated Service Date	Ongoing
Work Plan Category	Public Safety

Work Description:

This is a ten year Program that started in the fourth quarter of 2008 to protect the public from stray voltage associated with street lights. Over the next eight and a half years Consolidated Edison Inc. will continue to purchase and install isolation transformers and associated connectors in underground structures supplying streetlamps and traffic lights in New York City and Westchester, a total of 163,000 units. The installation of the isolation transformer will eliminate nearly 100% of expected stray voltage conditions (3,973 fewer conditions per year based on 2007 data).

From the time on inception of this program we have installed a total of 1,536 units, protecting a total of 1,788 streetlights. Our installation goals for 2009 and 2010 respectively are 8,800 units each year. For the years 2011 through 2016 our goal is to install a total of 16,000 units each year. Lastly, in the program completion year of 2017 we are expected to install a total of 14,610 units

Therefore, with the requested funding, we will be able to address all issues pertaining to the installation of isolation transformers. We are also purchasing more Iso's from the vendor than we are installing so that we always have an inventory on hand. This will allow us to install units and not have vendor manufacturing problems or delays. We will also end up with a small inventory to allow for the DOT installation of new intersections and any new streetlights.

Justification:

Isolation transformers create an isolated ungrounded circuit for each streetlight, a double-contingency design. This protects workers and the public against electric hazards due to cable failure, poor neutral connections or ineffective grounding which are responsible for the large numbers of stray voltage conditions found each year on streetlights. Because the circuit is ungrounded, current will not seek ground through any alternate path. In fact, with an isolation transformer installed, a person can safely handle the energized conductor bare handed. Also, as part of the isolation transformer installation process, unsafe connectors discovered in lamp bases will be removed and replaced with waterproof fuse holders and crimp connectors

Alternatives: We have looked into the use of GFCI's and also re-cabling every streetlight and neither alternative were effective or cost efficient when compared to installing an Isolation Transformer.

Risk of No Action: high public safety concern and endangerment of our workers

Estimated Completion Date: The program began in the fourth quarter of 2008 and is scheduled to be completed at the end of the third quarter in 2017

Status: 2008 and 2009 were approved, 2010 is pending approval

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Funding (\$000):

	Forecast 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013
Rep Crew Installations	4,000	4,000	4,000	4,000	4,000
Insp. Crew Installations	4,800	4,800	12,000	12,000	12,000
ISO's Installed	8,800	8,800	16,000	16,000	16,000
ISO Purchases	11,400	18,500	18,500	18,500	18,500
Material Cost (\$1K)	\$2,337	\$2,337	\$3,792	\$3,792	\$3,792
Labor Cost (\$1K)	\$3,153	\$3,153	\$6,371	\$6,371	\$6,371
Program Admin	\$319	\$319	\$319	\$319	\$319
Total Cost	\$5,809	\$5,809	\$10,482	\$10,482	\$10,482

Assumptions:

- There are 161,000 streetlight and traffic lights fed from an estimated 129,000 structures; each structure feeds an estimated 1.2 lamps.
- Dedicated inspection forces will complete 3 jobs per day with 2 man crews at \$84 man-hour rate. This cost includes the inspection, but is charged to the capital ISO program.
- Streetlight repair crews will use an incremental 1.5 hours extra with a 2 man crew at \$84 per hour, since they have access and inspection charged to the repair job.
- ISO purchases will be 160,300 1200VA units at \$201 ea (loaded cost), 2,200 2200VA units at \$355 ea (loaded cost) and 500 8000VA units at \$825 ea (loaded cost) for a total of 163,000 units. Larger units are for identified locations with greater loads such as large intersections or series circuits feeding multiple lights.

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	2,516

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
5,809	5,809	10,482	10,482	10,482	43,064

Addendum

The 2010 and 2011 reductions down to \$5.8M and \$8.2M have no impact on the overall Program. The reductions will be offset by increases in work completed from 2012 through 2017. See the chart below for changes for 2009 through 2013.

	Forecast 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013
Rep Crew Installations	5,200	5,200	5,200	6,200	6,200
Insp. Crew Installations	1,800	4,000	6,200	10,600	10,600
ISO's Installed	7,000	9,200	11,400	16,800	16,800
ISO Purchases	11,400	18,500	18,500	18,500	18,500
Material Cost (\$1K)	\$2,337	\$2,337	\$3,792	\$3,792	\$3,792
Labor Cost (\$1K)	\$2,115	\$3,098	\$4,081	\$6,299	\$6,299
Program Admin	\$319	\$319	\$319	\$319	\$319
Total Cost	\$4,771	\$5,754	\$8,193	\$10,411	\$10,411

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
5,809	8,145	10,482	10,482	34,918

Electric Operations Operations & Maintenance Summary (\$000)							
<u>Functional Category Work Activity</u>	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Yr Forecast (A+B)	Program Changes	April 1 2011 to March 31, 2012 Rate Yr Forecast	Program Changes April 1 2012 to March 31, 2013 Rate Yr Forecast
Public and Employee Safety	\$ 57,714	\$ 61,396	\$ (2,112)	\$ 55,602	\$ 2,540	\$ 58,142	\$ 3,653
Structure Inspections and Repairs	\$ 57,714	\$ 61,396	(\$2,112)	\$ 55,602	\$2,540	\$ 58,142	\$3,653
5 Year OH Inspection Program	176	2,539	2,960	3,136	122	3,258	127
5-Year UG Structure Inspection Program	35,728	37,519	(5,072)	30,656	2,418	33,074	3,526
Mobile Stray Voltage Testing - Sarnoff Devices	15,709	16,570	0	15,709	0	15,709	0

Project/Program Title	Mobile Stray Voltage Detection (SVD)
Status	Construction
Estimated Service Date	On-going
Work Plan Category	Public Safety

Work Description:

To survey the underground electrical distribution system in the Con Edison service territory for stray voltage utilizing mobile electric field detection. Stray voltages found are safe-guarded until repair crews mitigate the stray voltage conditions.

Upon detecting the presence of an electric field by the mobile detector, the testing contractor is required to conduct a manual field investigation to locate the source of the electric field. Upon discovery of stray voltage, contractors are required to make immediate notification to the Con Edison Call Center. The area where stray voltage is found is then cordoned off and safeguarded until repair crews respond to the location.

The Call Center upon receiving the notification by the testing contractor will create a trouble ticket (aka B-Ticket) which will automatically be generated at the respective Control Center who will in turn dispatch an Emergency Operations crew to respond to the stray voltage location. The Emergency crew (aka Troubleshooter) upon arrival will begin to investigate and eliminate the root cause of the stray voltage reported. The Emergency crew releases the site-safety contractor safeguarding the location. Locations where the Troubleshooter could only perform temporary repairs are referred to the corresponding Construction Department for permanent repair follow up.

Due to the volume of work generated by the mobile detection vehicles, Contractor Electricians are employed to support the Emergency Operations in responding to streetlight and traffic signal stray voltage B-Tickets.

Con Edison Construction Management (CM) and Central Quality Assurance perform work-in-progress as well as post work quality assurance audits to ensure the accuracy and completeness of the test results, proper work management and environmental health and safety compliance.

Units per Year: 65,000 miles for 12 routine scans.

Mandatory: Under the New York Public Service Commission (PSC) order Case 04-M-0159, Con Edison is mandated to complete twelve mobile stray voltage scans of the underground distribution system each rate year. In addition, Con Edison is mandated to conduct an annual mobile stray voltage detection survey of the underground electric distribution systems in appropriate areas of cities with a population of at least 50,000 until further Commission action.

High-level schedule: Twelve complete scans of the underground distribution system each rate year beginning April 1st and ending March 31st at a rate of approximately 1 scan per month. In addition, the qualifying cities of a population of 50,000 or greater will be scanned once, annually.

Justification:

The Mobile Stray Voltage Detection Program has made a significant contribution in improving public safety. In 2008, 10.6 routine surveys of the underground distribution system were completed. A total of 57,208 miles were covered and 4,866 stray voltages were detected. In the 2010 rate year, 12 system scans of the underground distribution system will be completed and approximately 65,000 miles will be covered.

Prior to April 2008 the program was operating under the initial goal of completing 8 scans. The 12-scan rate year target, commencing April 1, 2008 resulted in increased operational needs and resources. During the 2008 calendar year the program expenditures were approximately \$15.7 million. These expenditures reflect a portion of the increased operational costs associated with conducting 12 routine surveys during the rate year. To forecast for the completion of 12 routine scans and account for 1 annual scan, the 2010 funding request is the same as that for the 2009 rate year.

- Alternatives: The Mobile Stray Voltage Detection Program is mandated by the PSC therefore there are no alternatives to this program.
- Risk of No Action: Between 2004 and 2008, there has been a 94% reduction in Company related electric shock reports and a 67% reduction in all reported electric shocks (Company and Non-Company related). Since its inception in 2005, the Mobile Stray Voltage Detection Program has significantly contributed to the substantial reduction in electric shocks over the last four years. The risk of no action will be an adverse change in the reducing trend of electric shock reports. Subsequently the safety of employees and the public will be compromised.
- Summary of Financial Benefits and Costs: The program benefits are non-financial. Therefore, there are no direct financial benefits and/or costs associated with the program.
- Non-financial Benefits: Since the beginning of the program in 2005 the mobile detectors have covered approximately 97,000 miles and completed 17 full system scans in addition to partial scans and targeted area scans. Nearly 12,300 stray voltages have been detected since the inception of the program. The Mobile Stray Voltage Detection Program has been the most significant contributor to the reduction in reported electric shocks. The use of the SVD Vehicles allows for the detection and mitigation of stray voltage conditions not only on Company facilities but on non-Company facilities as well due to its all-inclusive testing methods in comparison to discrete testing methods. Since 2005, the number of system scans conducted each subsequent year has been significantly increased, with the number of surveys completed almost doubling from 2007 to 2008. Additional mobile scanning results in greater exposure to and finding of stray voltage conditions which may otherwise potentially manifest into a reported electric shock. The program has largely contributed to public safety by detecting 7,015 stray voltage conditions for which the Company was not responsible. This represents 57% of all the total stray voltages detected and is a testament to the non-financial benefits of the Mobile Stray Voltage Detection Program.
- Technical Evaluation/Analysis: Con Edison Distribution Engineering Department's on-going analysis of the overall number of stray voltage conditions found each year as a function of scan frequency, as well as other contributing variables, has projected a decline and eventual plateau of the number of stray voltages found. The plateau is expected to be a dramatically smaller number of stray voltages detected compared to historical results. Combined with this downward trend will be the reduction of reported electric shock occurrences.
- Sensitivity Analysis: The program funding will be greatly impacted if the following occurs:
 - Contractor bids exceed current costs. This will impact operational expenditures.
 - Increased occurrence of system events (i.e. fires, explosions, heat and rain storms) requiring greater reliance on Emergency Response resources. As a result, Emergency crews' response time and thereby standby time will increase and operational costs will be impacted.
 - Multiple winter storms that result in additional storm surveys. This will impact both operational and emergency response costs.

Most of these factors are difficult to predict and therefore forecast. All will result in increased program expenditures.

- Project Relationships: The Mobile Stray Voltage Detection Program is one of several programs working towards maintaining the safety of the public. In conjunction with the Inspection Programs, Annual Stray Voltage Testing Program, and the Cover Replacement Programs, the Mobile Stray Voltage Detection Program works toward reducing the number of electric shock incidents and maintaining public and employee safety.

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Estimated Completion Date: Each rate year's program will begin April 1st and be completed by March 31st.

Status: The program is in the 'Construction' phase.

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
0	2,226	4,592	11,314	15,709

Approved 2009	Forecast RYE 2011	Forecast RYE 2012	Forecast RYE 2013	Forecast Total 2011-2013
-	21,067	21,067	21,067	63,201

Addendum

Justification:

To forecast for the completion of 12 routine NYC network system scans and account for 1 annual scan in Westchester, the original 2010 funding request was for the same amount requested for the 2009 rate year. The 2008 contract rates, were used to project the RYE 2011 program changes. The filing however is being modified to reflect the new contract rates for testing and site-safety that is a result of a competitively bid contract which has been finalized since the original rate case filing. The table below shows the 2008 historical, the 2010 original, and the 2010 (Aug 2009 Update) program costs:

	2008 Historical	2010 (original filing)	2010 (August 2009 update)
Operations	\$12,379	\$16,953	\$11,890
#9 Emergency Response	\$2,959	\$3,629	\$3,629
Support	\$371	\$485	\$425
Total	\$15,709	\$21,067	\$15,944*

The 'Operations' line items reflect the costs associated with testing, electrician, and site-safety and the 'Support' line items reflect the costs associated with both the data and engineering resources.

The new contract rates provide a reduction in cost compared to the 2008 rates. The revised program funding being requested is presented in the Funding Table below.

*** Note the difference between the 2008 historical year and the current forecast is \$235,000 which will be funded internally in Electric Operations. No increase is required in this filing.**

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
0	2,226	4,592	11,314	15,709

Approved 2009	Forecast RYE 2011	Forecast RYE 2012	Forecast RYE 2013	Forecast Total 2011-2013
17,269	15,709	15,709	15,709	47,127

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Electric Operations Operations & Maintenance Summary (\$000)							
<u>Functional Category Work Activity</u>	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Yr Forecast (A+B)	Program Changes	April 1 2011 to March 31, 2012 Rate Yr Forecast	Program Changes April 1 2012 to March 31, 2013 Rate Yr Forecast
Emergency Response	\$ 78,781	\$ 86,194	\$ 6,484	\$ 85,265	\$ -	\$ 85,265	\$ -
Emergency Response	\$ 78,781	\$ 86,194	\$ 6,484	\$ 85,265	\$ -	\$ 85,265	\$ -
Underground Related Emergency Response			\$ 6,484	6,484	\$ -	6,484	\$ -

Project/Program Title	Underground Related Emergency Response
Status	Planning
Estimated Service Date	
Work Plan Category	System and Component Performance

Work Description:

The underground system costs associated with Emergency Response are understated for 2008 when looking at historical trends, 2008 had mild weather compared with 2007 and 2009. This mild weather resulted in the company incurring less emergency response costs to underground weather related events. The 2008 historical spending is below normal and since it is the base year for the rate case, spending should be adjusted to reflect three year historical average. As can be seen in the charts below, the number of manhole events and customer outages through June 2009 reflect a much higher activity when compared to the activity experienced through the full year in 2008. This higher trend is also reflected in our shunt, street light and bridging activity year to date when compared to the full year in 2008. In addition to the weather and work activity, after 2006 (LIC event), a LIC recommendation mandated a change in our mobilization process. This mobilization cost is reflected in 2007 – 2009.

Manhole Events and Salt Distribution (January-June)

	2007	2008	2009
Brooklyn	456	151	764
Manhattan	356	175	631
Bronx	210	77	253
Queens	358	111	470
Total (B/M/X/Q)	1561	688	2116
Total (System)	1581	701	2136
Salt (10K Tons)	25.61	8.51	25.16

Number of Customer Interruptions

Year	# of Cust Intr.
2007	176,430
2008	40,301
2009 (Jan-June)	35,348

Number of Shunts Received

Year	# of shunts received
2007	2123
2008	2598
2009 (Through June)	2063

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Number of Open Mains Received

Year	# of open mains received
2007	5712
2008	5675
2009 (Through May)	3719

Number of Street Lights Received

Year	# of street lights received
2007	8704
2008	8074
2009 (Through June)	5686

Number of Temporary Services Received

Year	# of Temporary Services (Bridges) received
2007	4754
2008	3308
2009 (Through May)	3263

	<u>2007 Actual</u>	<u>2008 Actual</u>	<u>2009 Budget</u>	<u>3 Year Avg 2007, 2008, 2009 Budget</u>
Basic labor	432,210	190,755	37,000	219,988
Man Hour labor	66,888,303	59,864,005	69,355,000	65,369,102
Materials	1,799,026	1,739,221	1,604,000	1,714,082
A/P	21,396,595	16,635,236	14,902,000	17,644,610
Taxes	306,739	351,588	296,000	318,109
Total	90,822,872	78,780,805	86,194,000	85,265,893

Alternatives: none

Estimated Completion Date: Ongoing

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Current Working Estimate (if applicable):

Funding (\$000): O&M

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
71,218	74,126	116,811	90,822	78,781

Approved 2009	Forecast RYE 2011	Forecast RYE 2012	Forecast RYE 2013	Forecast Total 2011-2013
86,194	85,266	85,266	85,266	255,798

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Page	DESCRIPTION	Rate Case Submission			
		2010	2011	2012	3 Year Total 2009-2011
	Strategic IT Enhancements	\$ 26,598	\$ 26,743	\$ 26,290	\$ 79,631
42	Outage Management System	2,300	2,300	2,300	6,900
44	Meter Shop ADAMS	2,750	1,000	-	3,750
46	ATS Automation	100	100	-	200
48	Energy Services Case Management	3,000	6,000	3,000	12,000
50	Power Quality (PQNodes) System Upgrade	1,650	1,145	-	2,795
52	SCADA Systems Consolidation	950	600	100	1,650
55	Electric Distribution Control Center Upgrades	3,000	3,000	3,000	9,000
57	Mapping System Upgrades	500	500	12,000	13,000
62	Distribution Engineering Workstation	-	-	500	500
64	Integrated System Model	1,750	1,500	-	3,250
68	Decision Aids	500	500	-	1,000
70	High Tension Monitoring Data Acquisition System	730	730	730	2,190
72	RMS Data Acquisition System	1,500	1,500	500	3,500
74	Heads Up Display	1,000	1,000	1,000	3,000
76	Secondary Visualization Model	2,553	2,553	1,160	6,266
79	Model Validation	2,000	2,000	2,000	6,000
81	Joint Use Pole Life Cycle Management System	2,315	2,315	-	4,630
	Total	\$ 26,598	\$ 26,743	\$ 26,290	\$ 79,631

Project/Program Title	Mapping Systems Upgrades
Status	Planning
Estimated Service Date	December 31, 2014
Work Plan Category	Strategic IT Enhancements

Work Description:

The Company continues to work towards improving its mapping systems for electric, gas and steam operations. Initially, these improvements will focus on establishing standards for land base and coordinate systems, and asset data quality. The improvements will enhance the functionality of the current systems and continue to establish a foundation for migrating to a single mapping platform for all business units. In 2011, focus will begin to switch towards replacing the current mapping applications and establishing a consolidated GIS platform.

2009 Work Description

- Define detailed business case and communicate strategy throughout business units
- Conduct analysis of land base standards, develop strategy, conduct pilot and develop deployment plan
- Establish strategy for real-world coordinates develop strategy, conduct pilot and develop deployment plan
- Determine disposition of M&S plates as reference.
- Conduct analysis of conduit and duct occupancy, vendor selection , and development of a detailed plan for conduit map data creation, registration and migration.
- Determine short-term disposition of Brooklyn IDMS mapping (write requirements document, determine if this will be done in-house or by a vendor, create a detailed plan).
- Define processes and technologies to be utilized to address asset data cleansing and continued data integrity
- Research and educate all stakeholders about GIS concepts, capabilities of vendor products and utility industry asset data models

2010 Work Description

- Complete land base standardization efforts begun in 2009
- Complete real-world coordinate efforts begun in 2009
- Continue data cleansing and quality initiatives begun in 2009
- Implement conduit and duct occupancy based on analysis completed in 2009
- Convert Brooklyn IDMS to new GIS platform
- Develop common conceptual electric GIS data model
- Begin formal vendor software evaluation
- Refine detailed business case and communicate strategy

2011 Work Description

Con Edison will commence a Phase 0 Assessment for Mapping Systems in 2011. A full time team comprised of key business users, Information Resources support staff and consultants, will be dedicated to this effort. The team will review all mapping-related business processes, conduct the planning and analysis necessary to streamline the business processes as appropriate and finalize a technology strategy for a consolidate GIS platform for Electric , Gas and Steam Operations.

The Phase 0 Assessment Team will compile a comprehensive report summarizing the work management business process changes, technology strategy, project cost estimate and implementation plan. The report will also include the following deliverables:

- Project charter statement

- Summary of streamlined business processes, developed by Operations personnel, addressing all aspects of mapping including a:
 - Summary of business processes and rules documented through use cases and decision trees
 - Summary of activities and/or business changes needed to achieve new business process
- Solutions summary and fit/gap analysis
- Summary of all required reports, interfaces, conversions and enhancements
- Summary of all benchmarking visits and project research
- Implementation project scope and exclusions
- Business case including ROI, summary of benefits and additional justifications
- Package selection decision or summary of enhancements to existing systems
- Request for Proposal (if required)
- Implementation team structure and summary of roles and responsibilities for all project resources
- Implementation schedule, including milestones and checkpoints
- Detailed cost estimate and cash flow summary for implementation
 - Software licenses and development
 - Computing infrastructure
 - Labor
 - Interfaces
 - Data Conversion
 - Testing
 - Training
 - Overheads and contingencies
- Testing strategy
- Change management plan addressing
 - Implementation impact on Operations personnel and other stakeholders
 - Implementation impact on existing systems

The overall business plan will include costs, constraints, justification and benefits with ROI, and a risk assessment. A high level business strategy will be conducted as the first scoping effort.

2012 Work Description

- Migrate data and establish new mapping environment for Brooklyn, including integration with engineering and operations models.
- Adopt the same process for Staten Island and commence system implementation.
- Adopt the same process for Queens and commence system implementation.

2013 Work Description

- Adopt the same process for Manhattan and commence system implementation.
- Adopt the same process for Bronx/ Westchester, and commence system implementation.
- Complete system implementation and integration efforts.

Justification:

Company forces and the customers they serve continue to demand more from corporate mapping systems. Increased demands from business units and customers for mapping data has also exposed issues with data synchronization, standardization and quality of asset data, and timeliness of data updates. Additionally, there are few robust, user-friendly tools that empower end users to query for analysis.

The current applications that are installed are truly AM/FM (Advanced Mapping and Facilities Mapping) not GIS (geographic information systems). The primary functions that the AM/FM applications support are facilities management; they do not easily perform spatial analysis. For decades the graphic display of the maps has been the primary use. The need for data and relational queries to support engineering, work management, asset management, and property records needs have increased. This makes the capability to

interrogate the data behind the map graphic and determine spatial relationships increasingly important for more than just taking an accurate printed map out to the field. The current applications do not support robust query and ad-hoc reporting for self-service so many requests need to be handled by the technical staff due to the limitations of the applications and nature of the data. Quick and flexible access to maps and spatial analysis will empower end users to more easily access data and simplify the capability for other applications to be integrated.

The Company operates and maintains six corporate mapping applications in support of its electric, gas and steam distribution systems. Significant business benefits can be realized by migrating to a single automated mapping / facilities management environment, with a single data model, and in giving the Company's facilities data a spatially accurate orientation. To the greatest extent possible, a new system would provide, either inherently or via extended applications, the functional capabilities of map viewing, plotting, specialty mapping, engineering design and system modeling that are in use in the existing environment.

Since the mapping systems were originally developed, Con Edison has undergone significant structural and organizational changes in response to the need to control costs. Operating groups centralized core functions and merged geographic areas in electric and gas distribution. For example, Bronx and Westchester Electric Operations were combined, as were Brooklyn and Queens. In the process, electric control centers were reduced from six to four. Similar consolidations were implemented in regional engineering organizations, where the use of multiple mapping applications becomes problematic. Gas Operations merged Bronx and Westchester operating groups, and those in Manhattan and Queens. Its gas control centers and engineering groups were reduced from four to one.

While operations across the regions have not yet been combined, there is potential benefit in having system platforms in place that facilitate standardized work practices. Especially in Electric Operations, reducing the number of mapping systems would have a favorable impact on operating and maintenance costs. Updating and maintaining multiple land bases and map products in a consolidated set of applications would be more efficient and provide the Company with more timely system updates. Furthermore, integration with the engineering and operations models, as well as other systems, would be greatly simplified and would better support corporate asset management and work management objectives.

The Company's mapping systems include VISION (Intergraph FRAMME-based applications in support of all gas and all electric secondary facilities), Feeder Mapping System (separate non-FRAMME application for electric primary – feeders), Electric Distribution Facilities Information System (application developed for Staten Island electric primary, secondary and C&DO maps), Intelligent Database Mapping System (maintains Brooklyn's electric primary, secondary and C&DO maps), Steam Operations Mapping Information System (for the entire steam distribution system), and Electric Transmission (AutoCAD). With the exception of the IDMS system in Brooklyn that is exclusively Oracle, all Con Edison's mapping systems use Bentley Microstation as the graphics engine, although other, ancillary data is stored in AutoCAD (e.g., Electric Transmission).

Specifically with respect to Electric Operations, the following issues must be addressed:

- Existing data needs to be consolidated into a single data model, and data standards must be established and adopted across all operating regions
- Existing landbases must be replaced with spatially accurate base maps available from New York City and Westchester County; existing electric data must be registered to these base maps, inheriting "real-world" coordinates in the process
- Existing systems need to be replaced with contemporary technology, with an eye towards reducing the long-term cost of ownership

- Conduit maps, which currently reside in only raster format, ultimately need to be converted to a digital format and their contents referenced to the same NYC and Westchester landbases

Alternatives: The following alternatives were considered:

- Alternative 1: Migrate to one of the existing platforms.
- Alternative 2: Continue maintaining the current mapping platforms

Both alternatives were dismissed because they did not meet the following strategic goals:

- Strategically position Con Edison to leverage technology shifts toward GIS
- Gain operational efficiencies in the area of AM/FM/GIS since this functionality is not available or limited in the current mapping applications
- Maintain a standards based system that is easier to support and obtain support as necessary

Risk of No Action: In addition to internal grounds for looking towards a more consolidated mapping environment, changes in the direction of the present Intergraph FRAMME technology are making the need to investigate other options a high priority. Because of a recent announcement by Intergraph to discontinue evolving the FRAMME technology product and shifting the company's focus towards a more GIS-type of technology (its "G-technology") the need to evaluate the impacts of staying with the existing platform or migrating towards a new platform to support AM/FM/GIS has now become a strategic imperative for all Intergraph FRAMME users.

Non-financial Benefits:

- Strategically position Con Edison to leverage technology shifts toward GIS
- Gain operational efficiencies in the area of AM/FM/GIS since this functionality is not available or limited in the current mapping applications
- Maintain a standards based system that is easier to support and obtain support as necessary

Technical Evaluation/Analysis:

Two studies have been conducted with respect to planning for GIS

- Enspira study in 2006. This produced a high level plan and rough order of magnitude estimates for establishing a common GIS for electric, gas and steam.
- Micon Group study in 2008. This produced 3 roadmap scenarios focused on electric for GIS, work management, SCADA and asset management.

Project Relationships: In 2009 the Company will initiate a Phase 0 Assessment for Electric Operations Work Management. This will be followed by the implementation of a new work management solution for Electric Operations. The scope and complexity of this effort has caused the Company to postpone the establishment of a consolidated mapping platform until the implementation of the work management solution is underway.

Estimated Completion Date: December 31, 2014

Status: Planning Phase, 0% completed

Funding (\$000s): Capital

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	-

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
2,900	2,000	2,000	12,000	12,360	31,260

Addendum

Since the 2009 budget was reduced to \$500K, priority was given to determining the short-term disposition of Brooklyn IDMS mapping. A proposal to migrate data from the current Brooklyn mapping application and integrate it into Con Edison's VISION (Intergraph FRAMME) platform has been reviewed. This body of work will be piloted with data from the Richmond Hill network for electric secondary and conduit/duct occupancy. Based on the pilot results a determination will be made to migrate the remaining Brooklyn secondary and conduit/duct occupancy onto the FRAMME platform. An evaluation of the short-term disposition of electric primary data will also be conducted in 2010.

The plan to commence a Phase 0 assessment for Mapping Systems in 2011 will remain. This Phase 0 plan was scheduled for 2011 in favor of benefitting from process changes that are anticipated from the current work management project. Some of the work items in 2009 and 2010 were enhancements that would benefit the existing platforms while creating foundational changes for the future. Rather than defer the Phase 0 plans any further some of the work items proposed for pilots and/or implementation on existing platforms will become analysis-only efforts. In addition, the Electric Mapping Committee and the IT group will work together to focus on analysis and communication of strategy on landbase; real-world coordinates; data quality; and overall GIS education. This change in approach will affect the following work items previously planned for 2009 and 2010:

Previous Plan Years	Work item	Impact
2009 & 2010	Define detailed business case and communicate strategy throughout business units. Refine detailed business case and communicate strategy.	Begin business case in 2010. Completion of business case and communication will be deferred until 2011 as a precursor to the Phase 0 assessment.
2009 & 2010	Conduct analysis of land base standards, develop strategy, conduct pilot and develop deployment plan. Complete land base standardization efforts begun in 2009.	Analysis and strategy will be conducted in 2010. No pilots will be conducted.
2009 & 2010	Establish strategy for real-world coordinates develop strategy, conduct pilot and develop deployment plan. Complete real-world coordinate efforts begun in 2009.	Analysis and strategy will be conducted in 2010. No pilots will be conducted.
2009	Determine disposition of M&S plates as reference.	Defer until 2011 as part of Phase 0 assessment.
2009 & 2010	Conduct analysis of conduit and duct occupancy, vendor selection, and development of a detailed plan for conduit map data creation, registration and migration. Implement conduit and duct occupancy based on analysis completed in 2009.	Analysis and strategy will be conducted in 2010. No pilots or implementations will be conducted.

2009 & 2010	Define processes and technologies to be utilized to address asset data cleansing and continued data integrity. Continue data cleansing and quality initiatives begun in 2009.	Data cleansing will continue to be emphasized as part of day-to-day maintenance. The mapping committee will continue to work with IT and engineering areas to refine software where possible within the maintenance budget and enforce data standards.
2009 & 2010	Research and educate all stakeholders about GIS concepts, capabilities of vendor products and utility industry asset data models, Begin formal vendor software evaluation.	In 2010 IT and the Electric Mapping Committee will work together to educate themselves on GIS concepts, capabilities of vendor products and utility industry asset data models. Other stakeholder education will be deferred until 2011. Formal vendor software evaluation will be deferred as part of Phase 0 assessment.

Funding (\$000s): Capital

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
500	500	12,000	12,360	25,360

Project/Program Title	Distribution Engineering Workstation (DEW)
Status	Ongoing
Estimated Service Date	2012
Work Plan Category	Strategic IT Enhancements

Work Description:

The Company will be utilizing new circuit analysis software called Distribution Engineering Workstation ("DEW"). This software was initially developed through the Electric Power Research Institute ("EPRI") as a classical engineering analysis tool. However, over the past few years, the Company has been working with its initial designer (i.e., Electrical Distribution Design) to further develop and substantially enhance the functionality of DEW as part of an initiative that will integrate this circuit analysis software into many of the Company's other mission critical systems. It will become a key tool for enhanced distribution engineering planning and analysis, as well as for real-time control center operations. This model will serve as the foundation of the "Smart Grid of the Future" Con Edison system.

The first stage of this project integrates DEW into the necessary Con Edison systems. Software and interfaces are being developed that allow for the creation and automatic update of an electrical system model using various types of Con Edison mapping systems. Using historical load research data, customer load statistics and load profiles have been created for use in the DEW models. Automated extract of monthly Kwh billing data from the Company's customers is also planned.

The second stage of this project is building the Company's circuits within DEW. In 2007, Staten Island and the Manhattan Sutton Network were manually built in DEW. In 2008, development has begun on a circuit builder that will automatically extract the data from the Company's mapping and data systems, converting it into a working DEW model. The Pennsylvania, Fashion, and Hudson Yards networks will be built in 2008 to validate the circuit builder. In the following years, the remaining networks in Manhattan will be built and a circuit builder that integrates with the Brooklyn Queens and Westchester mapping systems will be developed.

The third stage of this project is the development of a real time "virtual" supervisory control system. This stage provides for integration of DEW with the Company's various data acquisition ("SCADA") systems. Real time values of substation voltages and currents, switch information, power quality data, etc., will be used by DEW to determine calculated loads and voltages on the entire distribution system. These calculated loads and voltages comprise the "virtual" supervisory control system and will enable DEW to be used as a powerful control center operating tool.

Justification:

The DEW system model will serve as the plant model for the Company's electrical system, allowing a lean management approach to engineering, operations, and planning. The DEW software integrates the transmission, distribution, and customer into one model, allowing more accurate analysis than the current segregated models the Company uses. Using a single, integrated model, will also aid contingency and reliability analysis and allow the same model that is used for engineering analysis and planning to be used for control center operations.

DEW integrates load statistics derived from historical data, including customer usages and weather patterns, for use in forecasting. This will allow the Company to better plan how many crews it needs available based on weather and system load, increasing the efficiency of our emergency response. Additionally, the real time "virtual" supervisory control system in DEW will allow the Company to better monitor customer voltage and current, improving service. Detecting problems at the customer level, such as low or varying voltage, will be expedited so that the Company can respond more quickly. Also, the Company will be better able to observe changes within the system that may warn of future problems, and can respond to situations before any actual problems occur.

2010 Capital –Electric Operations

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The DEW model also provides a platform for integrating machine learning into the Company's system analysis and emergency response procedures. Machine Learning is an adaptive dynamic programming that couples a system model and existing information to create intelligence that optimizes the system in the face of uncertain outside conditions. Concurrent with the DEW project, the Company is working with Columbia University to research the development of mathematical algorithms that use statistics and historical data derived from the Company's information systems to link specific system characteristics with resulting events. The result will allow greater system automation and will improve control center operations.

Estimated Completion Date: 2012

Status:

In 2007, we worked with EDD to manually built DEW models of Staten Island and of the Sutton Network in Manhattan. These models are currently being validated. A DEW circuit builder is under development to automate the modeling process. Interfaces between the various Con Edison information systems and the new DEW circuit builder for EDFIS and Vision are in development.

Funding (\$000):

Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008
-	-	-	-	(152)

Approved 2009	Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2009-2013
500	500	500	500	-	2,000

Addendum

Eliminating the funding for DEW for 2010 and 2011 will inhibit our ability to provide the platform to respond to some of the findings of the management audit:

- Con Edison needs to develop an integrated vision and plan for the electric system and link capital investment to economic or value-driven parameters;
- Con Edison needs to develop a more holistic approach to cost management;

DEW also provides the platform to perform simulations of potential outcomes based on forecasted load, enabling more optimal capital investments. This goes hand in hand with the findings of the management audit in regards to Con Edison needing an expanded long-term view of the forecasting function.

DEW is currently the only modeling tool that we and the utility industry have experienced to allow us to integrate the transmission and distribution systems into one platform to allow us to plan and develop an integrated vision and plan, by deferring this project by an additional two years, our ability to perform such engineering function effectively will be inhibited.

Funding (\$000):

Forecast 2010	Forecast 2011	Forecast 2012	Forecast 2013	Forecast/Approved Total 2010-2013
0	0	500	-	500

Page	Work Plan Category	System & Transmission Operations Operation and Maintenance Summary (\$000)							
		2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Year Forecast (A+B)	Program Changes	April 1, 2011 to March 31, 2012 Rate Year Forecast	Program Changes	April 1, 2012 to March 31, 2013 Rate Year Forecast
	Efficiency and Process Improvement	64	1,300	3,161	3,225	425	3,650	(1,175)	2,475
2	Conductor Cart Training	-	25	75	75	(75)	-	-	-
4	Live Line Method Procedures	-	75	175	175	-	175	(125)	50
6	Training Specialist for TLM Programs	60	150	90	150	-	150	-	150
8	Update Plan and Profile Drawings	4	50	46	50	-	50	(50)	-
10	QBB - Pipe Inspection / Refurbishment Program	-	-	500	500	500	1,000	(1,000)	-
13	EMS Project Completion	-	900	900	900	-	900	-	900
14	Operations Analysis and System Support	-	-	650	650	-	650	-	650
16	Senior Planning Analyst - NYISO Functions	-	100	100	100	-	100	-	100
17	ECC Trainer and Compliance	-	-	125	125	-	125	-	125
21	Transmission Planning Positions (3 employees)	-	-	300	300	-	300	-	300
23	NERC Compliance & Standards Implementation	-	-	200	200	-	200	-	200
	Sub-total	64	1,300	3,161	3,225	425	3,650	(1,175)	2,475

Project/Program Title	Sequence and Scheduling – Add 3 rd SDO
Status	On-going
Estimated Service Date	On-going
Work Plan Category	Efficiency and Process Improvement

Removed

**TRANSMISSION and DISTRIBUTION ELECTRIC RATE CASE
2009 - 2013 CAPITAL WORK PLAN**

	Historical Expenditures										TOTAL		
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2009-2012	2013	2009-2012
Sub-Total Substation Operations	\$ 224,218	\$ 290,351	\$ 401,989	\$ 476,104	\$ 380,245	\$ 344,435	\$ 265,335	\$ 228,240	\$ 359,170	\$ 343,800	\$ 853,345	\$ 343,800	\$ 1,541,580
Distribution Unit Substations	7,547	9,555	11,931	10,398	11,308	6,000	4,452	3,511	3,511	3,150	11,474	3,150	20,624
SUBSTATION	\$ 232,165	\$ 299,907	\$ 413,000	\$ 486,502	\$ 391,553	\$ 350,435	\$ 270,387	\$ 231,751	\$ 362,681	\$ 346,950	\$ 864,819	\$ 346,950	\$ 1,562,204
TRANSMISSION	22,712	46,590	41,783	46,491	124,293	210,174	179,105	98,485	82,980	91,800	360,570	91,800	662,544
SYSTEM OPERATIONS	4,853	10,312	19,836	13,231	12,767	12,300	9,350	3,250	4,150	4,700	16,750	4,700	33,750
SYSTEM & TRANSMISSION	\$ 27,375	\$ 56,902	\$ 61,719	\$ 59,722	\$ 137,020	\$ 222,474	\$ 188,455	\$ 101,735	\$ 87,130	\$ 96,500	\$ 377,320	\$ 96,500	\$ 896,294
**DISTRIBUTION	\$ 496,823	\$ 650,437	\$ 812,500	\$ 910,835	\$ 1,040,366	\$ 898,064	\$ 871,775	\$ 856,350	\$ 899,451	\$ 880,132	\$ 2,628,076	\$ 880,132	\$ 4,416,272
T&D ELECTRIC SUB-TOTAL	\$ 756,363	\$ 1,007,246	\$ 1,287,219	\$ 1,457,059	\$ 1,568,939	\$ 1,470,973	\$ 1,330,617	\$ 1,190,336	\$ 1,349,262	\$ 1,333,582	\$ 3,970,216	\$ 1,333,582	\$ 5,674,770
ELECTRIC PRODUCTION	\$ 20,686	\$ 46,896	\$ 36,770	\$ 44,327	\$ 36,200	\$ 37,400	\$ 39,650	\$ 35,760	\$ 39,300	\$ 37,500	\$ 114,700	\$ 37,500	\$ 189,600
T&D ELECTRIC TOTAL	\$ 776,951	\$ 1,054,142	\$ 1,323,989	\$ 1,501,386	\$ 1,605,139	\$ 1,508,373	\$ 1,370,267	\$ 1,226,096	\$ 1,388,562	\$ 1,371,082	\$ 3,984,916	\$ 1,371,082	\$ 5,864,370
CONSTRUCTION	\$ 272	\$ 514	\$ 2,429	\$ 2,605	\$ 2,326	\$ 2,715	\$ 3,000	\$ 2,897	\$ 4,500	\$ 5,000	\$ 10,397	\$ 5,000	\$ 18,112
CENTRAL ENGINEERING	\$ 327	\$ 1,710	\$ 1,662	\$ 1,305	\$ 1,314	\$ 1,350	\$ 1,250	\$ 1,000	\$ 1,000	\$ 1,000	\$ 3,250	\$ 1,000	\$ 5,600
Total	\$ 777,550	\$ 1,055,366	\$ 1,328,080	\$ 1,505,296	\$ 1,608,779	\$ 1,512,438	\$ 1,374,517	\$ 1,228,983	\$ 1,394,062	\$ 1,377,082	\$ 3,993,562	\$ 1,377,082	\$ 5,883,082

**Note - Includes Interference (Municipal Infrastructure) which is represented by their own exhibits and testimony and Excludes common information technology initiatives (IT Initiatives)

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS					
	\$000s				
	2009 - 2013 Five Year Plan				
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
INCREASED CUSTOMER DEMAND	\$ 164,380	\$ 57,985	\$ 25,300	\$ 144,300	\$ 126,300
Astor- Establish New Station	3,000				
Emergent Load Relief Program	-	1,300	1,300	1,300	1,300
Newtown-Establish Station	92,780	42,000	-	-	-
Parkchester-Install 3rd Cap Bank	-	-	1,000	1,000	-
Parkchester-Install 4th Transformer	-	-	3,000	12,000	5,000
Transformer Cooling Program	1,000	-	-	-	-
Woodrow-Install Third Transformer And Fresh Kills Expand 138kV Station	25,000	12,185	-	-	
York-Establish New Area Substation	40,000	2,500	20,000	130,000	120,000
Nevins-Establish New Station	2,600				
GENERATION INTERCONNECTION					
Astoria East-Install Phase Angle Regulator	-	-	-	-	-
Corona-Install Series Reactor*	-	-	-	-	-
Sub-Total	\$ 164,380	\$ 57,985	\$ 25,300	\$ 144,300	\$ 126,300
SYSTEM AND COMPONENT PERFORMANCE	\$ 160,250	\$ 183,450	\$ 180,940	\$ 193,370	\$ 200,500
EQUIPMENT					
138kV Circuit Breaker Program Upgrade Program	11,700	11,700	11,700	11,700	11,700
345kV Circuit Breaker Upgrade Program	5,000	5,000	5,000	5,000	5,000
Circuit Switcher Replacement Program	500	500	500	500	500
Condition Based Monitoring Equipment	250	250	250	250	250
Corona - Breaker Addition (6S and 8X)	3,000	2,650	-	-	-
Bus Section Upgrade - E. 63rd Street	-	-	-	-	-
Elmsford-Upgrade of Elmsford - Substation	25,000	32,000	27,740	1,750	-
Failed Equipment Other Than Transformers	1,500	1,500	1,500	1,500	1,500
Failed Transformer Program	30,046	25,800	24,700	23,000	23,000
Rainey-Replace Temp Transformer With Permanent	-	-	-	-	-
Replace Disconnect Switches	4,600	4,600	4,800	4,800	4,800
Replace Overduted 13/27kV Circuit Breaker Programs	10,800	10,800	10,800	10,800	10,800

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS					
	\$000s				
	2009 - 2013 Five Year Plan				
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
Transformer Replacement Programs	13,000	20,500	20,000	21,000	21,000
Sub-Total	\$ 105,396	\$ 115,300	\$ 106,990	\$ 80,300	\$ 78,550
RELAY					
Control Cable Upgrade Program	1,000	1,000	1,000	1,000	1,000
Relay Modifications	5,500	5,500	5,500	5,500	5,500
Upgrade Analog Circuits To Digital Fiber	2,000	2,000	1,800	-	-
Relay Protection System Redundancy (Single Point of Failure)	-	-	-	30,000	40,000
Sub-Total	\$ 8,500	\$ 8,500	\$ 8,300	\$ 36,500	\$ 46,500
MISCELLANEOUS COMPONENTS					
Additional G&T Devices	500	500	500	500	-
Area Substation Reliability And Auto Ground Circuit Switchers	10,500	10,500	10,500	10,500	10,500
Capacitor Cable Upgrade Program	3,000	3,000	3,000	1,000	-
Category Alarms	2,250	2,250	2,250	2,250	2,250
Construct Relay Enclosure Houses	1,500	1,500	1,500	1,500	1,500
Corona Settlement	1,000	1,000			
DC System Upgrade Program	3,500	3,500	3,500	3,500	3,500
Diesels / Black start Restoration (Phase 2) - Upgrade Station L & P	1,000	1,000	1,000	1,000	-
E. 13th Street - Alarm Panel Replacement and Control Systems	-	-	1,500	4,500	
E179th Street-Substation - Bus Section Upgrade Program	-	6,000	15,000	25,000	32,000
East River-Protection System Upgrade	3,500	3,500	3,100	2,520	-
Facility Improvement Program	6,000	6,000	6,000	6,000	6,000
Fire Suppression System Upgrades	-	8,000	6,000	6,000	6,000
High Voltage Test Sets	3,500	5,000	3,000	4,000	4,000
New Maximo Upgrade	400	-	-	-	
Rapid Restore Enhancements- Expansion of TOMS	200	200	-	-	
Reinforced Ground Grid	500	700	700	700	700
Revenue Metering Upgrade	500	500	500	-	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SUBSTATION OPERATIONS CAPITAL PROJECTS						
DESCRIPTION	\$000s					
	2009 - 2013 Five Year Plan					
	2009 Revised Budget	2010	2011	2012	2013	
Roof Replacement Program	3,000	3,000	2,100	2,100	3,000	
Small Capital Equipment Program	3,454	3,000	3,000	3,000	3,000	
Substation Loss Contingency	1,000	2,000	2,000	2,000	2,000	
Switchgear Enclosure Upgrade Program	500	500	500	500	1,000	
White Plains-Substation - Bus Section Upgrade Program	550					
Sub-Total	\$ 46,354	\$ 59,650	\$ 65,650	\$ 76,570	\$ 75,450	
ENVIRONMENTAL						
Environmental Risk Mitigation	\$ 12,000	\$ 15,000	\$ 15,000	\$ 15,000	\$ 12,000	
Pumping Plant Improvement	3,500	3,500	3,500	3,500	3,500	
PURS Supervisory Control & Data Acquisition	5,500	8,500	8,500	8,500	8,500	
Sub-Total	3,000	3,000	3,000	3,000	-	
PUBLIC AND EMPLOYEE SAFETY						
Security Enhancements	\$ 12,000	\$ 15,000	\$ 15,000	\$ 15,000	\$ 12,000	
Sub-Total	\$ 3,100	\$ 4,000	\$ 4,000	\$ 4,000	\$ 2,000	
STRATEGIC IT ENHANCEMENTS						
SOCSS - RTU Replacement	3,100	4,000	4,000	4,000	2,000	
Sub-Total	\$ 4,705	\$ 5,500	\$ 3,000	\$ 2,500	\$ 3,000	
Substation Automation Target Information System	1,000	2,000	2,000	2,000	2,000	
Technology Improvements	705	500	500	500	1,000	
Sub-Total	\$ 4,705	\$ 5,500	\$ 3,000	\$ 2,500	\$ 3,000	
TOTAL SUBSTATION OPERATIONS	\$ 344,435	\$ 265,935	\$ 228,240	\$ 359,170	\$ 343,800	

Shaded columns indicate rate years 2010 to 2012

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS SYSTEM OPERATION CAPITAL PROGRAMS					
(\$000s)					
2009 - 2013 Five Year Plan					
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
STRATEGIC IT ENHANCEMENTS	\$ 12,300	\$ 9,350	\$ 3,250	\$ 4,150	\$ 4,700
Bulk Power Improvements					
SOCCS Visualization	500	500			
District Operations Improvement					
System Operation Enhancements	250	400	300	300	300
District Operator Task Managing System	250	400	250	300	300
Operation Management System Enhancements	500	1,000	400	400	1,000
EMS-Continuance					
EMS Reliability AECC and ECC	-	500	1,000	500	500
Work Management Systems					
Distribution Orders Enhancements	250	250	300	350	300
Outage Scheduling System	1,000	3,000			
Facilities / Utilities Improvement					
ECC/AECC Facility Security Enhancements	300	300			500
Computer Room Renovation			500	1,000	1,000
ECC UPS Battery Replacement				500	200
Training Area Expansion	750	750			
Add Diesel Generator	-				
East Control Room Renovations	3,000				
Operator Console Replacement	1,600				
HVAC Upgrade - East Computer Room	500				
Command and Control Programs	-				

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS SYSTEM OPERATION CAPITAL PROGRAMS					
(\$000s)					
2009 - 2013 Five Year Plan					
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
Operations Requirements					
Interface with NYISO	100	100	100	100	100
Plant Information System	-	300		200	
Cyber Security	200	300	200	300	300
Operations Network for EMS	100	250	200	200	200
Control Center Phone System Replacement		1,300			
Max Generation / Fast Load Pick-up	400				
GT Remote Start System	600				
New EMS					
Replacement Program SOCCS-X Energy Management System	2,000				
Sub-Total	12,300	9,350	3,250	4,150	4,700
TOTAL SYSTEM OPERATION	\$ 12,300	\$ 9,350	\$ 3,250	\$ 4,150	\$ 4,700
Shaded columns indicate rate years 2010 to 2012					

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SYSTEM AND TRANSMISSION OPERATIONS CAPITAL PROJECTS
TRANSMISSION OPERATIONS CAPITAL PROJECTS / PROGRAMS

DESCRIPTION	\$000s				
	2009 - 2013 Five Year Plan				
	2009 Revised Budget	2010	2011	2012	2013
INCREASED CUSTOMER DEMAND	\$ 181,144	\$ 155,500	\$ 63,000	\$ 14,500	\$ 19,000
Dynamic Feeder Rating	1,000	1,000	1,000	1,000	1,000
Reconductor Feeders 45 and 46				10,000	18,000
Vernon - W49th St-38M72 Upgrade	20,144	19,500	7,000	3,500	
179th St-Reinforcement - M29 (Includes Academy)	160,000	135,000	55,000	-	-
Sub-Total	\$ 181,144	\$ 155,500	\$ 63,000	\$ 14,500	\$ 19,000
SYSTEM AND COMPONENT PERFORMANCE	\$ 27,800	\$ 22,430	\$ 33,910	\$ 67,680	\$ 72,000
Feeder 34182/4	-	-	-	3,000	-
Manhattan-Replace 69kV Feeders On QBB	-	-	-	3,000	14,000
Millwood-Replace Wood Poles W/Steel Poles	100				
Sprain Brook - W 49th St-Feeder M51	-	-	-	-	-
Staten Island-Feeders 38R51 And 38R52	-	-	4,210	13,000	8,000
Cable System Enhancement - Pothead Alarms	1,200				
Emergent Transmission Reliability	4,000	10,000	10,000	10,000	10,000
Re-Conductor Dunwoodie -- Sprain Brook Transmission Corridor	-	-	5,400	5,280	
Reinforce Hudson River Crossing Towers	3,000	1,800	1,800		
Replace 69M43/69M44 With 38M53 & 38M54	3,000				
Replace Feeder 69M41 & 69M45	-	1,000	5,000	18,000	18,000
Replacement of Feeders 18001 & 18002	8,000	2,180		8,000	14,000
Transmission Feeder Failures	5,000	5,000	5,000	5,000	5,500
Upgrade Overhead 345kV Transmission Structures	2,100	2,200	2,300	2,400	2,500
Replace potheads on Feeder 34184 (Astoria/Corona)	(100)	-	-	-	-
M-Line Tower Relocation	1,500	-	-	-	-
Phasor Measuring Units for SCADA Real Time Operation	-	250	200	-	-
Sub-Total	\$ 27,800	\$ 22,430	\$ 33,910	\$ 67,680	\$ 72,000
ENVIRONMENTAL	\$ 1,230	\$ 1,175	\$ 1,575	\$ 800	\$ 800
DEC Program Line	1,230	775	775		
Environmental Enhancements	-	400	800	800	800
Sub-Total	\$ 1,230	\$ 1,175	\$ 1,575	\$ 800	\$ 800
TOTAL TRANSMISSION OPERATIONS	\$ 210,174	\$ 179,105	\$ 98,485	\$ 82,980	\$ 91,800

Shaded columns indicate rate years 2010 to 2012

Consolidated Edison Company of New York, Inc.
System and Transmission Operations
Operation and Maintenance Programs

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System & Transmission Operations Operation and Maintenance Summary (\$000)												
Functional Category Work Activity	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Year Forecast (A + B)	Program Changes	April 1, 2011 to March 31, 2012 Rate Year Forecast	Program Changes	April 1, 2012 to March 31, 2013 Rate Year Forecast
Scheduled Maintenance												
Manhole Inspections	\$ 437	\$ 473	\$ 370	\$ 453	\$ 817	\$ 700	\$ 133	\$ 950	\$ -	\$ 950	\$ -	\$ 950
Low / Medium Pressure	1,150	1,103	1,192	1,347	1,242	1,089	108	1,350	-	1,350	-	1,350
Vent Chamber Cleaning	67	64	41	50	69	51	-	69	-	69	-	69
Oil/Gas Samples - EO Spec	37	8	15	-	3	53	-	3	-	3	-	3
Operational Maintenance												
Engineering Requests	62	79	15	45	13	134	-	13	-	13	-	13
Partial Discharge / Rainey Tunnel Inspections	77	172	249	150	111	245	64	175	-	175	-	175
Other - Safety Program, Maintenance	336	5	34	174	149	-	-	149	-	149	-	149
OH Line Inspections	665	512	499	656	666	623	-	666	-	666	-	666
Vegetation Management - Tree Trimming	1,298	1,568	1,556	2,187	1,470	1,614	144	1,614	-	1,614	-	1,614
Vegetation Inventory	62	395	366	270	252	390	-	252	-	252	-	252
Total Scheduled Maintenance	\$ 4,191	\$ 4,399	\$ 4,337	\$ 5,332	\$ 4,792	\$ 4,899	\$ 449	\$ 5,241	\$ -	\$ 5,241	\$ -	\$ 5,241
Scheduled Maintenance - Programs												
Coating Refurbishment	-	915	999	474	162	875	1,338	1,500	-	1,500	-	1,500
PFT Injection	35	320	549	1,184	2,025	199	(2,025)	-	-	-	-	-
Manhole Refurbishment	742	675	834	1,199	935	1,023	64	1,000	-	1,000	-	1,000
Furnace Brook Lake Dam Maintenance	-	43	4	273	25	75	1,775	1,800	(1,650)	150	-	150
Tower Painting	149	244	1	-	93	100	47	140	-	140	-	140
Roadway Access	205	154	65	454	274	150	-	274	-	274	-	274
Operation Drills	18	116	23	75	74	111	-	74	-	74	-	74
Security Improvements	-	78	93	38	73	60	-	73	-	73	-	73
PFT Patrols	-	-	-	-	342	300	258	800	-	800	-	800
Improve Overhead Transmission Restoration Capability	-	-	-	-	680	-	-	680	-	680	-	680
Install Bird Discouragers	-	-	-	-	-	70	270	270	(270)	-	-	-
Conductor Cart Training	-	-	-	-	-	25	75	75	(75)	-	-	-
Live Line Method Procedures	-	-	-	-	-	75	175	175	-	175	(125)	50
Training Specialist for TLM Programs	-	-	-	-	60	150	90	150	-	150	-	150
Update Plan and Profile Drawings	-	-	-	-	4	50	45	50	-	50	(50)	-
QBB - Pipe Inspection / Refurbishment Program	-	-	-	-	-	-	500	500	500	1,000	(1,000)	-
Total Scheduled Maintenance Programs	\$ 1,149	\$ 2,745	\$ 2,558	\$ 3,697	\$ 4,748	\$ 3,263	\$ 2,613	\$ 7,361	\$ (1,495)	\$ 5,866	\$ (1,175)	\$ 4,691
Non-Scheduled Maintenance												
Feeder Emergencies	6,709	6,234	11,444	4,808	8,011	6,708	-	8,011	-	8,011	-	8,011
Corrosion and Irregularity Program												
Corrosion Repairs	1,048	538	788	464	451	657	99	550	-	550	-	550
Irregularity Repairs	1,834	3,504	3,255	3,655	3,225	3,292	-	3,225	-	3,225	-	3,225
DGOA Samples	38	46	22	21	16	73	-	16	-	16	-	16
Manhole Cleaning	535	657	541	439	353	541	97	450	-	450	-	450
Tower Repairs - Lights and Other	261	338	240	396	283	390	127	390	-	390	-	390
Conductor Repairs	166	387	95	230	188	450	262	450	1,000	1,450	(1,000)	450
ROW Roads and Trails / Fences and Gates	147	245	108	147	277	108	-	277	-	277	-	277
Total Non-Scheduled Maintenance	\$ 10,538	\$ 11,947	\$ 16,473	\$ 10,160	\$ 12,784	\$ 12,217	\$ 585	\$ 13,369	\$ 1,000	\$ 14,369	\$ (1,000)	\$ 13,369

Consolidated Edison Company of New York, Inc.
System and Transmission Operations
Operation and Maintenance Programs

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(\$000)												
Functional Category Work Activity	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	Program Changes	April 1, 2010 to March 31, 2011 Rate Year Forecast	Program Changes	April 1, 2011 to March 31, 2012 Rate Year Forecast	Program Changes	April 1, 2012 to March 31, 2013 Rate Year Forecast
Capital Associated Expense												
Capital Associated Expense Projects	58	54	1	-	(4)	-	-	(4)	-	(4)	-	(4)
Total Capital Associated Expense	\$ 58	\$ 54	\$ 1	\$ -	\$ (4)	\$ -	\$ -	\$ (4)	\$ -	\$ (4)	\$ -	\$ (4)
Inter Utility												
O&R and PJM Lines Maintenance	396	438	686	552	545	525	430	975	(290)	685	295	980
Total - Inter Utility	\$ 396	\$ 438	\$ 686	\$ 552	\$ 545	\$ 525	\$ 430	\$ 975	\$ (290)	\$ 685	\$ 295	\$ 980
Antenna Installation												
Antenna Installation	(67)	3	(4)	-	350	(300)	(350)	-	-	-	-	-
Total - Antenna Installation	\$ (67)	\$ 3	\$ (4)	\$ -	\$ 350	\$ (300)	\$ (350)	\$ -	\$ -	\$ -	\$ -	\$ -
Total - Transmission Operations	\$ 16,265	\$ 19,585	\$ 24,061	\$ 19,741	\$ 23,215	\$ 20,604	\$ 3,727	\$ 26,942	\$ (785)	\$ 26,157	\$ (1,880)	\$ 24,277
System Operations	15,020	16,206	16,893	16,548	17,699	18,375	-	17,699	-	17,699	-	17,699
EMS Project Completion	-	-	-	-	-	900	900	900	-	900	-	900
Communications Infrastructure	3,446	3,436	3,800	4,557	4,971	5,100	259	5,230	-	5,230	-	5,230
Scheduling DO	-	-	-	-	66	100	-	100	-	100	-	100
ECC Trainer and Compliance	-	-	-	-	-	-	125	125	-	125	-	125
Operations Analysis and System Support	-	-	-	-	-	-	650	650	-	650	-	650
Total - System Operations	\$ 18,466	\$ 19,642	\$ 20,693	\$ 21,105	\$ 22,736	\$ 24,475	\$ 1,934	\$ 24,704	\$ -	\$ 24,704	\$ -	\$ 24,704
Transmission Planning	1,943	2,265	2,596	2,833	2,883	3,105	-	2,883	-	2,883	-	2,883
Planning Studies	184	287	18	21	-	-	100	100	-	100	-	100
State Transmission Assessment & Reliability Study	-	-	-	-	-	-	100	100	(20)	80	-	80
Transmission Planning Positions (3 employees)	-	-	-	-	-	-	300	300	-	300	-	300
NERC Compliance & Standards Implementation	-	-	-	-	-	-	200	200	-	200	-	200
Total - Transmission Planning	\$ 2,137	\$ 2,552	\$ 2,614	\$ 2,854	\$ 2,883	\$ 3,105	\$ 700	\$ 3,583	\$ (20)	\$ 3,563	\$ -	\$ 3,563
Department Office	932	849	1,138	1,049	1,062	1,108	-	1,062	-	1,062	-	1,062
Transmission Reliability Group Fees	90	115	85	105	113	150	47	150	-	150	-	150
Senior Planning Analyst - NYISO Functions	-	-	-	-	-	100	100	100	-	100	-	100
Total - Department Office	\$ 1,022	\$ 984	\$ 1,223	\$ 1,154	\$ 1,175	\$ 1,358	\$ 147	\$ 1,322	\$ -	\$ 1,322	\$ -	\$ 1,322
Grand Total	\$ 37,890	\$ 42,744	\$ 48,581	\$ 44,854	\$ 60,009	\$ 49,542	\$ 6,508	\$ 58,551	\$ (805)	\$ 55,746	\$ (1,880)	\$ 53,855

Work Plan Category	Project / Program Description	System & Transmission Operations Operation and Maintenance Summary (\$000)							
		2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Year Forecast (A+B)	Program Changes	April 1, 2011 to March 31, 2012 Rate Year Forecast	Program Changes	April 1, 2012 to March 31, 2013 Rate Year Forecast
Efficiency and Process Improvement		64	1,300	3,161	3,225	425	3,650	(1,175)	2,475
	Conductor Cart Training	-	25	75	75	(75)	-	-	-
	Live Line Method Procedures	-	75	175	175	-	175	(125)	50
	Training Specialist for TLM Programs	60	150	90	150	-	150	-	150
	Update Plan and Profile Drawings	4	50	46	50	-	50	(50)	-
	QBB - Pipe Inspection / Refurbishment Program	-	-	500	500	500	1,000	(1,000)	-
	EMS Project Completion	-	900	900	900	-	900	-	900
	Operations Analysis and System Support	-	-	650	650	-	650	-	650
	Senior Planning Analyst - NYISO Functions	-	100	100	100	-	100	-	100
	ECC Trainer and Compliance	-	-	125	125	-	125	-	125
	Transmission Planning Positions (3 employees)	-	-	300	300	-	300	-	300
	NERC Compliance & Standards Implementation	-	-	200	200	-	200	-	200
	Sub-total	64	1,300	3,161	3,225	425	3,650	(1,175)	2,475
Environmental		829	1,273	1,971	2,800	(1,650)	1,150	-	1,150
	Corrosion Repairs	451	657	99	550	-	550	-	550
	Manhole Cleaning	353	541	97	450	-	450	-	450
	Furnace Brook Lake Dam Maintenance	25	75	1,775	1,800	(1,650)	150	-	150
	Sub-total	829	1,273	1,971	2,800	(1,650)	1,150	-	1,150
Public and Employee Safety		928	945	197	1,125	-	1,125	-	1,125
	Manhole Inspections	817	700	133	950	-	950	-	950
	Partial Discharge / Rainey Tunnel Inspections	111	245	64	175	-	175	-	175
	Sub-total	928	945	197	1,125	-	1,125	-	1,125
System and Component Performance		12,700	11,585	1,179	13,879	420	14,299	(705)	13,594
	Low / Medium Pressure	1,242	1,089	108	1,350	-	1,350	-	1,350
	Vegetation Management - Tree Trimming	1,470	1,614	144	1,614	-	1,614	-	1,614
	Coating Refurbishment	162	875	1,338	1,500	-	1,500	-	1,500
	PFT Injection	2,025	199	(2,025)	-	-	-	-	-
	Tower Painting	93	100	47	140	-	140	-	140
	PFT Patrols	342	300	258	600	-	600	-	600
	Install Bird Discouragers	-	70	270	270	(270)	-	-	-
	Tower Repairs - Lights and Other	263	390	127	390	-	390	-	390
	Conductor Repairs	188	450	282	450	1,000	1,450	(1,000)	450
	O&R and PJM Lines Maintenance	545	525	430	975	(290)	685	295	980
	Communications Infrastructure	4,971	5,100	259	5,230	-	5,230	-	5,230
	Planning Studies	-	-	100	100	-	100	-	100
	State Transmission Assessment & Reliability Study	-	-	100	100	(20)	80	-	80
	Transmission Reliability Group Fees	113	150	47	160	-	160	-	160
	Manhole Refurbishment	936	1,023	64	1,000	-	1,000	-	1,000
	Antenna Installation	350	(300)	(350)	-	-	-	-	-
	Sub-total	12,700	11,585	1,179	13,879	420	14,299	(705)	13,594
	TOTAL S & TO	14,521	15,103	6,508	21,029	(805)	20,224	(1,880)	18,344

Consolidated Edison Company of New York, Inc.
Electric Operations
Capital Programs

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2009 - 2013 Five Year Plan					
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
Increased Customer Demand	\$ 321,038	\$ 249,823	\$ 245,157	\$ 250,658	\$ 252,862
New Business					
New Business Capital	157,089	123,000	122,000	122,000	122,000
Meter Installation	17,724	17,771	18,071	18,071	18,071
Sub-Total	\$ 174,813	\$ 140,771	\$ 140,071	\$ 140,071	\$ 140,071
System Reinforcement Area SS Load Relief					
Newtown	14,000	4,000	-	-	-
Astor (Herald Sq. Transfer)	2,000	-	-	-	-
Penn/Waterside	-	4,600	900	-	-
Randall's Island	14,284	-	-	-	-
City Hall to Cortlandt	500	200	-	-	-
York to Lenox Hill	-	-	-	7,000	10,900
Chelsea W 19th St. to Murray Hill	\$ -	\$ -	\$ 3,700	\$ 2,900	\$ -
Sub-Total	\$ 30,784	\$ 8,800	\$ 4,600	\$ 9,900	\$ 10,900
Base Growth / Relief					
Primary Feeder Relief	33,179	33,583	32,525	32,122	31,874
Network Load Relief Transformer Installations	51,025	45,620	46,158	46,460	46,460
NonNetwork Fdr Relief (Open Wire)	14,438	8,605	9,125	9,226	9,474
Overhead Transformer Relief	500	2,642	2,642	2,642	2,642
Sub-Total	\$ 99,142	\$ 90,450	\$ 90,450	\$ 90,450	\$ 90,450
Distribution Substation					
Distribution Substation Load Relief	4,534	-	-	-	1,000
Spill Prevention Control Counter Measures	(584)	-	-	-	-
Sub-Total	\$ 3,950	\$ -	\$ -	\$ -	\$ 1,000
Meter Purchase	12,349	9,802	10,036	10,237	10,441
System and Component Performance	\$ 376,117	\$ 426,168	\$ 415,047	\$ 445,653	\$ 434,929
Enhanced Reliability					
Elmsford Refurbishment	-	-	1,300	2,000	-
59th Street Bridge Crossing	-	-	-	2,000	5,000
(PPrimary) Cable Crossings	6,265	8,000	8,000	9,000	-
HiPot	3,363	3,400	3,400	6,100	6,100
PILC	19,832	27,085	27,085	33,000	33,000
Transformer Remote Monitoring System 3rd Generation Transmitter	11,153	7,850	7,500	7,000	6,600
Sectionalizing Switches	3,562	3,562	3,562	4,501	4,501
Underground Secondary Reliability Program	21,896	37,422	40,866	50,009	50,546
Secondary Open Mains	144,032	139,245	129,871	129,871	129,871
Grounding Transformers	2,123	550	520	520	520
Shunt Reactors	-	2,761	2,788	2,790	2,790
Network Reliability	14,847	21,323	22,145	26,545	26,545
Coastal Storm Risk Mitigation	197	1,000	1,000	3,000	3,000
Transformer Purchase	129,518	144,606	138,640	138,750	137,250
Sub-Total	\$ 356,788	\$ 396,804	\$ 386,677	\$ 415,086	\$ 405,723

Consolidated Edison Company of New York, Inc.
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Capital Programs

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2009 - 2013 Five Year Plan					
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
Distribution Substation Modernization					
Tap Changer Position Indicator System	81	132	-	-	-
Temperature Gauges	300	100	100	100	100
USS Transformer Replacement	-	600	600	600	600
4kV USS Switchgear Replacement	600	2,200	1,200	1,200	1,200
USS Life Extension Program	505	1,170	1,361	1,361	-
Auto Reclose On Bank Breakers	156	250	250	250	250
Facility Improvement	325	-	-	-	-
Breaker Replacement	83	-	-	-	-
Sub-Total	\$ 2,050	\$ 4,452	\$ 3,511	\$ 3,511	\$ 2,150
Overhead Enhancement					
C Truss Program	1,600	1,752	1,752	2,058	2,058
Autoloop Reliability	4,349	7,359	7,528	7,450	7,450
Aerial (Okonite) Cable Replacement	1,621	1,009	1,009	2,550	2,550
#4,#6 Self Supporting Wire	3,166	3,169	3,175	3,175	3,175
Overhead Feeder Sectionalizing Program	4,231	3,189	3,202	3,452	3,452
Automated Emergency Ties	-	750	750	750	750
Overhead Feeder Reliability	-	750	1,125	1,125	1,125
Rear-Lot Pole Elimination	437	1,437	1,437	1,437	1,437
Enhanced 4kV Grid Monitoring	-	-	-	-	-
4kV UG Reliability	475	1,111	1,111	1,111	1,111
Overhead Conductor Clearance	-	1,630	1,622	-	-
Overhead Secondary Reliability Program	-	500	500	500	500
Targeted Primary DBC Replacement	-	-	-	800	800
URD Cable Rejuvenation/Fault Indicator	-	806	198	198	198
ATS Installation USS Reliability XW	1,400	1,450	1,450	2,450	2,450
Total	\$ 17,279	\$ 24,912	\$ 24,859	\$ 27,056	\$ 27,056
Emergency Response	\$ 137,746	\$ 126,525	\$ 124,075	\$ 124,075	\$ 124,075
Emergency Primary Cable Replacement	62,984	56,056	53,856	53,856	53,856
Overhead	12,466	14,267	14,267	14,267	14,267
Emergency Service Replacement	20,251	20,053	20,053	20,053	20,053
Street Lights	19,357	15,003	14,753	14,753	14,753
Transformer Installation	22,688	21,146	21,146	21,146	21,146
Total	\$ 137,746	\$ 126,525	\$ 124,075	\$ 124,075	\$ 124,075
Public Safety	\$ 15,988	\$ 21,243	\$ 27,079	\$ 29,416	\$ 29,416
Vented Manhole Cover	5,586	-	-	-	-
Vented Service Box Covers	5,589	11,875	15,375	15,375	15,375
Isolation Transformers	4,813	5,809	8,145	10,482	10,482
Pressure, Temperature, and Oil Sensors	-	3,559	3,559	3,559	3,559
Total	\$ 15,988	\$ 21,243	\$ 27,079	\$ 29,416	\$ 29,416
Environmental	\$ 600	\$ 600	\$ 600	\$ -	\$ -
Oil Minders	600	600	600	-	-
Total	\$ 600	\$ 600	\$ 600	\$ -	\$ -

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2009 - 2013 Five Year Plan					
DESCRIPTION	2009 Revised Budget	2010	2011	2012	2013
Strategic IT Enhancements	\$ 18,827	\$ 26,598	\$ 26,743	\$ 26,290	\$ 14,538
Outage Management System	3,000	2,300	2,300	2,300	-
Meter Shop ADAMS	-	2,750	1,000	-	-
4kV Load Shedding System	-	-	-	-	-
ATS Automation	150	100	100	-	-
Energy Services Case Management	600	3,000	6,000	3,000	-
Power Quality (PQNodes) System Upgrade	1,650	1,650	1,145	-	-
SCADA Systems Consolidation	800	950	600	100	-
Electric Distribution Control Center Upgrades	500	3,000	3,000	3,000	-
Mapping System Upgrades	500	500	500	12,000	12,360
Distribution Engineering Workstation	48	-	-	500	-
Grid Optimization	-	-	-	-	-
Integrated System Model	1,827	1,750	1,500	-	-
Decision Aids	239	500	500	-	-
High Tension Monitoring Data Acquisition System	730	730	730	730	178
RMS Data Acquisition System	-	1,500	1,500	500	-
Heads Up Display	500	1,000	1,000	1,000	-
Secondary Visualization Model	3,500	2,553	2,553	1,160	-
Model Validation	1,750	2,000	2,000	2,000	2,000
Joint Use Pole Life Cycle Management System	1,600	2,315	2,315	-	-
Other Initiatives	1,433	-	-	-	-
Total	\$ 18,827	\$ 26,598	\$ 26,743	\$ 26,290	\$ 14,538
Efficiency and Process Improvement	\$ 5,303	\$ 29,700	\$ 28,200	\$ 28,700	\$ 17,100
Work Management Systems	5,003	29,700	28,200	28,700	17,100
Accounting by Network	300	-	-	-	-
Total	\$ 5,303	\$ 29,700	\$ 28,200	\$ 28,700	\$ 17,100
TOTAL ELECTRIC OPERATIONS	\$ 875,619	\$ 880,657	\$ 866,901	\$ 904,792	\$ 872,920
Shaded columns indicate rate years 2010 to 2012					

Consolidated Edison Company of New York, Inc.
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(\$000)												
<u>Functional Category Work Activity</u>	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Yr Forecast (A+B)	Program Changes	April 1 2011 to March 31, 2012 Rate Yr Forecast	Program Changes	April 1 2012 to March 31, 2013 Rate Yr Forecast
Emergency Response	\$ 71,218	\$ 74,126	\$ 116,811	\$ 90,822	\$ 78,781	\$ 86,194	\$ 6,484	\$ 85,265	\$ 0	\$ 85,265	\$ 0	\$ 85,265
Underground Related Emergency Response	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 6,484					
Bridge Resolution												
Maintenance associated with Capital	\$ 10,972	\$ 9,777	\$ 14,002	\$ 13,954	\$ 13,174	\$ 10,880	\$ 1,618	\$ 14,792	\$ 200	\$ 14,992	\$ 0	\$ 14,992
Scada System Consolidation - Mac			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 200	\$ 200	\$ -	\$ 200
OH Conductor Clearance Program			\$ -	\$ -	\$ -	\$ -	\$ 169	\$ 169	\$ -	\$ 169	\$ -	\$ 169
Rear Lot Pole Elimination			\$ -	\$ -	\$ 23	\$ -	\$ 1,449	\$ 1,472	\$ -	\$ 1,472	\$ -	\$ 1,472
Transformer Inspections and Repairs	\$ 21,386	\$ 27,497	\$ 33,265	\$ 38,918	\$ 32,643	\$ 32,445	\$ 0	\$ 32,643	\$ 0	\$ 32,643	\$ 0	\$ 32,643
Structure Inspections and Repairs	\$ 17,999	\$ 11,898	\$ 19,265	\$ 32,582	\$ 57,714	\$ 61,398	\$ (2,112)	\$ 55,602	\$ 2,540	\$ 58,142	\$ 3,653	\$ 61,795
5 Year OH Inspection Program			\$ -	\$ -	\$ 176	\$ 2,539	\$ 2,960	\$ 3,136	\$ 122	\$ 3,258	\$ 127	\$ 3,385
5-Year UG Structure Inspection Program	\$ 15,740	\$ 7,262	\$ 9,377	\$ 15,840	\$ 35,728	\$ 37,519	\$ (5,072)	\$ 30,656	\$ 2,418	\$ 33,074	\$ 3,526	\$ 36,600
Mobile Stray Voltage Testing - Sarnoff Devices		\$ 2,226	\$ 4,592	\$ 11,314	\$ 15,709	\$ 16,570	\$ -	\$ 15,709	\$ -	\$ 15,709	\$ -	\$ 15,709
Overhead Equipment	\$ 1,311	\$ 1,367	\$ 15,904	\$ 5,198	\$ 1,264	\$ 1,859	\$ 0	\$ 1,264	\$ 0	\$ 1,264	\$ 0	\$ 1,264
Line Clearance	\$ 6,699	\$ 7,284	\$ 10,092	\$ 13,529	\$ 14,051	\$ 14,747	\$ 3,033	\$ 17,084	\$ 597	\$ 17,681	\$ 620	\$ 18,301
Danger Tree Removal	\$ -	\$ -	\$ -	\$ -	\$ 644	\$ 633	\$ 501	\$ 1,145	\$ 40	\$ 1,185	\$ 42	\$ 1,227
Line Clearance Program	\$ 6,699	\$ 7,284	\$ 10,092	\$ 13,529	\$ 13,407	\$ 14,114	\$ 2,532	\$ 15,939	\$ 557	\$ 16,496	\$ 578	\$ 17,074
Street Lights	\$ 4,860	\$ 2,832	\$ 2,641	\$ 4,112	\$ 5,583	\$ 6,157	\$ 0	\$ 5,583	\$ 0	\$ 5,583	\$ 0	\$ 5,583
Meters & Other Customer Equipment	\$ 10,053	\$ 10,355	\$ 9,818	\$ 9,639	\$ 8,934	\$ 8,457	\$ 0	\$ 8,934	\$ 0	\$ 8,934	\$ 0	\$ 8,934
Field Operations / Unit Substations	\$ 14,521	\$ 17,588	\$ 20,327	\$ 21,801	\$ 19,418	\$ 20,558	\$ 0	\$ 19,418	\$ 0	\$ 19,418	\$ 0	\$ 19,418
Subtotal - Distribution Field Operations	\$ 159,019	\$ 162,724	\$ 242,125	\$ 230,555	\$ 231,562	\$ 242,693	\$ 9,023	\$ 240,585	\$ 3,337	\$ 243,922	\$ 4,273	\$ 248,195
Engineering & Services	\$ 25,873	\$ 24,792	\$ 25,599	\$ 25,750	\$ 26,256	\$ 33,265	\$ 1,256	\$ 27,512	\$ (740)	\$ 26,772	\$ (65)	\$ 26,707
Automatic Transfer Switch Operator Replacement			\$ -	\$ -	\$ 900	\$ 900	\$ -	\$ 900	\$ (740)	\$ 160	\$ -	\$ 160
Unit Substation Repairs and Inspection			\$ 300	\$ -	\$ 1,283	\$ -	\$ 449	\$ 1,732	\$ -	\$ 1,732	\$ -	\$ 1,732
Trip Coil Monitor			\$ -	\$ -	\$ 5	\$ 104	\$ 410	\$ 415	\$ -	\$ 415	\$ (65)	\$ 350
Electric Distribution Equipment Reconditioning & Repairs	\$ 2,347	\$ 1,730	\$ 811	\$ 692	\$ 762	\$ 1,159	\$ 397	\$ 1,159	\$ -	\$ 1,159	\$ -	\$ 1,159
Subtotal - Electric Operations	\$ 184,892	\$ 187,516	\$ 267,724	\$ 256,305	\$ 257,818	\$ 275,958	\$ 10,279	\$ 268,097	\$ 2,597	\$ 270,694	\$ 4,208	\$ 274,902
Energy Services	\$ 7,746	\$ 7,799	\$ 7,335	\$ 7,443	\$ 7,546	\$ 6,699	\$ 123	\$ 7,669	\$ 0	\$ 7,669	\$ 0	\$ 7,669
Energy Services Case Management					\$ -	\$ -	\$ 123	\$ 123	\$ -	\$ 123	\$ -	\$ 123
Total - Electric Operations	\$ 192,638	\$ 195,315	\$ 275,059	\$ 263,748	\$ 265,364	\$ 282,657	\$ 10,402	\$ 275,766	\$ 2,597	\$ 278,363	\$ 4,208	\$ 282,571

Electric Operations Operations & Maintenance Summary (\$000)							
Functional Category Work Activity	2008 Actual (A)	2009 Forecast	Program Changes (B)	April 1, 2010 to March 31, 2011 Rate Yr Forecast (A+B)	Program Changes	April 1 2011 to March 31, 2012 Rate Yr Forecast	Program Changes April 1 2012 to March 31, 2013 Rate Yr Forecast
Emergency Response	\$ 78,781	\$ 86,194	\$ 6,484	\$ 85,265	\$ -	\$ 85,265	\$ - \$ 85,265
Emergency Response	\$ 78,781	\$ 86,194	\$ 6,484	\$ 85,265	\$ -	\$ 85,265	\$ - \$ 85,265
Underground Related Emergency Response			\$ 6,484	6,484	\$ -	6,484	\$ - 6,484
System and Component Performance	\$ 55,492	\$ 58,892	\$ 5,510	\$ 61,002	\$ (143)	\$ 60,859	\$ 555 \$ 61,414
Maintenance associated with Capital	\$ 13,174	\$ 10,880	\$1,618	\$ 14,792	\$0	\$ 14,792	\$0 \$ 14,792
OH Conductor Clearance Program	0		169	169	0	169	0 169
Rear Lot Pole Elimination	23		1,449	1,472	0	1,472	0 1,472
Engineering & Services	\$ 28,267	\$ 33,265	\$ 859	\$ 29,126	\$ (740)	\$ 28,386	\$ (65) \$ 28,321
Automatic Transfer Switch Operator Replacement	900	900	0	900	(740)	160	0 160
Unit Substation Repairs and Inspection	1,283		449	1,732	0	1,732	0 1,732
Trip Coil Monitor	5	104	410	415	0	415	\$ (65) 350
Line Clearance	\$ 14,051	\$ 14,747	\$3,033	\$ 17,084	\$597	\$ 17,681	\$620 \$ 18,301
Danger Tree Removal	644	633	501	1,145	40	1,185	42 1,227
Line Clearance Program	13,407	14,114	2,532	15,939	557	16,496	578 17,074
Public and Employee Safety	\$ 57,714	\$ 61,396	\$ (2,112)	\$ 55,602	\$ 2,540	\$ 58,142	\$ 3,653 \$ 61,795
Structure Inspections and Repairs	\$ 57,714	\$ 61,396	(\$2,112)	\$ 55,602	\$2,540	\$ 58,142	\$3,653 \$ 61,795
5 Year OH Inspection Program	176	2,539	2,960	3,136	122	3,258	127 3,385
5-Year UG Structure Inspection Program	35,728	37,519	(5,072)	30,656	2,418	33,074	3,526 36,600
Mobile Stray Voltage Testing - Samoff Devices	15,709	16,570	0	15,709	0	15,709	0 15,709
Efficiency and Process Improvement	\$ 762	\$ 1,159	\$ 397	\$ 1,159	\$ -	\$ 1,159	\$ - \$ 1,159
Engineering & Services	\$ 762	\$ 1,159	\$ 397	\$ 1,159	\$ -	\$ 1,159	\$ - \$ 1,159
Electric Distribution Equipment Reconditioning & Repairs	762	1,159	397	1,159	0	1,159	0 1,159
Strategic IT Enhancements	\$ 7,546	\$ 6,699	\$ 123	\$ 7,669	\$ 200	\$ 7,869	\$ - \$ 7,869
Energy Services	\$ 7,546	\$ 6,699	123	\$ 7,669	\$200	\$ 7,869	\$0 \$ 7,869
Scada System Consolidation - Mac	0		0	0	200	200	0 200
Energy Services Case Management	-		123	123	-	123	- 123
Total Electric Operations	\$200,295	\$214,340	\$ 10,402	\$ 210,697	\$ 2,597	\$ 213,294	\$ 4,208 \$ 217,502