STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on December 10, 2008

COMMISSIONERS PRESENT:

Garry A. Brown, Chairman
Patricia L. Acampora
Maureen F. Harris
Robert E. Curry, Jr.

CASE 04-M-0159 - Proceeding on Motion of the Commission to Examine the Safety of Electric Transmission and Distribution Systems.

CASE 06-M-1467 - Petition of Orange and Rockland Utilities, Inc. to Modify Its Stray Voltage Testing Program.

ORDER ADOPTING CHANGES TO ELECTRIC SAFETY STANDARDS

(Issued and Effective December 15, 2008)

BY THE COMMISSION:

The Commission's Electric Safety Standards have been in place since January 2005. Through experience and lessons learned over the past three years, Staff has identified several areas in the standards that require clarification and elaboration. As a result, Staff proposed revisions that encompass several necessary modifications, including a calendar year testing cycle and standard testing and reporting requirements to provide for consistent application of the standards statewide. On July 8, 2008, a Notice Soliciting Comments was issued seeking input on Staff's proposed revisions (initial proposal). Where appropriate, the initial proposal has been modified based on comments received and adopted herein.

In addition, in a petition dated November 30, 2006, Orange & Rockland Utilities, Inc. (ORU) requested that the Commission modify the Electric Safety Standards contained in Case 04-M-0159 to relax the testing standards for the company. ORU requested that the current annual stray voltage testing cycle for overhead and underground facilities (with the exception of streetlights) be revised to a five-year cycle to coincide with the facility inspection program. We conclude that the data compiled for the first three years of the testing program on a statewide basis indicates that instances of stray voltage continue to be found sufficiently often and therefore the testing intervals should not be extended at this time. Therefore, we deny ORU's petition.

BACKGROUND

On January 5, 2005, the Commission adopted a set of Electric Safety Standards that established proactive steps for ensuring the safety of the public from stray voltage and enhancing the reliability of the electric system in the State of New York. The Electric Safety Standards include: (1) annual stray voltage testing of electric facilities accessible to the public using qualified voltage detection devices; (2) inspections of utility electric facilities on a minimum of a five-year cycle; (3) recordkeeping, certification, quality assurance and reporting requirements; and (4) adoption of the National Electric Safety Code as the minimum standard governing utility construction, maintenance, and operations. The standards also require that where a utility finds stray voltage, it must immediately make the facility safe and repair it within 45 days.

In a July 2005 Order, the Commission modified certain aspects of the Electric Safety Standards in response to a joint petition for rehearing from Central Hudson Gas & Electric (Central Hudson), New York State Electric & Gas (NYSEG), National Grid, and Rochester Gas & Electric (RGE), and individual petitions from NYSEG, RGE and ORU. It extended the date for testing of overhead distribution and transmission facilities, including substations, to August 31, 2006, for electric utilities other than Con Edison. All utilities, however, were still required to complete testing on underground facilities and streetlights by November 30, 2005. Additionally, the requirements for certification of the test results by a company officer were clarified and the need for interior inspections of fiberglass handholes[1] was eliminated.

THE ORU PETITION

On November 30, 2006, ORU filed a petition for a waiver from performing stray voltage testing on distribution and transmission facilities annually. Instead, ORU proposes that it test for stray voltage on these facilities as part of its five-year inspection programs, and continue testing streetlights on an annual basis. From the data compiled for the first three years of the testing program, we find that new instances of stray voltage have been found in each year that testing has been done. Moreover, the data from the most recent year of testing do not reflect a trend such that the level of risk from stray voltage is reduced to the point that a relaxation of the testing program such as is sought by O&R would be granted. Therefore, we deny ORU's petition.

SUMMARY OF ISSUES

In response to the July 8, 2008 notice, several parties filed formal comments. The six major electric utilities filed comments collectively (Joint Utilities) and individually. In general, the individual utility comments support the positions presented by the Joint Utilities, but did present additional proposals for consideration. In addition, several other parties filed comments, including the Jodie S. Lane Public Safety Foundation (Lane Foundation), the New York State Consumer Protection Board (CPB), the City of Yonkers, the New York City Department of Transportation, the Town of Huntington, and Power Survey Corporation (the company that offers mobile stray voltage detection services). Where comments were directly germane to the published notice, they have been addressed. If, in our estimation, the remainder provide an improvement to the standards they were analyzed and adopted where appropriate.

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[1] Fiberglass handholes are utilized on underground residential distribution systems as splice points for electric service conductors.

The following sections describe the areas of concern with respect to the Electric Safety Standards. Each section addresses Staff's initial proposed revisions, comments received by parties, and a discussion including the final recommendations. Appendix A contains the final revisions of the standards.

Stray Voltage Testing Equipment and Detection Range

Staff Proposal

Staff proposed revising the definition of Stray Voltage Testing found in Section 1, paragraph (e) as follows:

> The process of checking an electric facility for stray voltage using a hand-held device capable of reliably detecting and audibly and/or visually signaling voltage in the range of ~~8~~ 4.5 to 600 volts.

In practice, all of the investor-owned utilities and many of the municipal electric utilities chose to use a handheld device (HD detector), with a certified voltage range from 5 to 600 V, with a tolerance of +/- 10%. Experience with this device revealed that it is capable of indicating the presence of voltage below the 4.5 volt rating. Staff recommended that the required voltage range of the detector be revised to reflect the certified rating of the equipment currently being utilized.

Summary of Comments

Joint Utilities takes issue with Staff's proposal, and they propose an alternative value of 6 V, which they contend is consistent with the tolerances included in the manufacturer's documentation for the hand held device most widely used for this testing. They also claim this revision would be consistent with the detection capability of the mobile stray voltage detector currently used by Con Edison in its secondary network distribution system. The Joint Utilities takes issue with Staff's proposal because 4.5 V represents the best accuracy of the detectors rather than the certified rating with a tolerance range and proposes an alternative value of 6 V. It contends the 6 V is consistent with the tolerances included in the manufacturer's documentation for the hand held device most widely used for this testing.

Discussion

The Joint Utilities correctly indicate that the threshold values for the HD detector are 5 to 600 V, with a tolerance of +/- 10%, yielding a lower threshold value of 5.5 V on the high end. Upon consideration, it seems that Staff's initial recommendation is overly aggressive, particularly with respect to the possibility that additional manufacturers of testing devices may be entering the market, and a threshold value at that level may impede competitors from providing their services to the utilities. Staff also reports that the manufacturer of the mobile testing device confirms Joint Utilities contention that the 6 V value is consistent with its specifications. As a result, we will adopt this value and revise the standards to reflect this change.[2]

The point offered by the Joint Utilities with respect to mobile testing raises an issue that we will address now. Mobile testing is utilized by Con Edison in a wide swath of its secondary network distribution system in addition to the manual testing currently required in the standards. Earlier this year, Con Edison filed a petition, including a testing report prepared by an independent and certified testing facility, seeking approval to use the mobile detector exclusively to comply with the testing requirements contained in the standards and forgo manual testing in areas where the mobile testing can be performed successfully. Staff evaluated the petition and requested that additional testing be done to allay concerns about the mobile detector's capability under certain conditions, and also to verify its ability to detect voltage less than 5 V. The requested supplemental testing has been performed, and a report was submitted by the independent and certified testing facility. Staff's concerns about the capabilities and performance of the mobile testing technology have been addressed. To ensure that the standards are updated to reflect the advances in available technology, we will take this

[2] See page 1 of Appendix A, Section 1, paragraph (e). For consistency, Section 3, paragraph (g) will also be revised to reflect the lower value of 6 V (p.2).

opportunity to also revise the definition of Stray Voltage Testing and delete the reference to "hand held" testing, thus eliminating the limitation that testing with hand held devices is the only acceptable method to achieve compliance with the standards.

Definition of Finding and Mitigation Requirements

Staff Proposal

Staff proposed new definitions of "Finding" and "Mitigation" in Section 1 and revising Section 3, paragraph (h) to require mitigation of all findings, as follows:

> Section 1(f) Findings – Any confirmed voltage reading on an electric facility greater than or equal to 1V measured using a volt meter and a 500 ohm shunt resistor.
>
> Section 1(g) Mitigation – Necessary actions performed by the utility to effectively eliminate the stray voltage findings.
>
> Section 3(h) - Any facility for which ~~the testing device indicates the presence of voltage~~ a finding is discovered shall be guarded by the utility immediately and continuously until the utility has eliminated the stray voltage and made the area safe. The utility must ~~take corrective action~~ perform mitigation irrespective of whether the stray voltage is determined to be caused by its own or a customer-owned facility. Mitigation shall be completed on any voltage findings.

As the safety standards are currently structured, there is no formal definition for what should be considered, in practice, a stray voltage condition that would require action on the part of the utility. Currently Con Edison, as part of its testing protocol when utilizing the mobile detection system, identifies and attempts to mitigate any findings greater than or equal to 1V, and the Staff proposal was based on that protocol.

Summary of Comments

The Joint Utilities contend that the Staff proposal to define a stray voltage finding as any reading greater than or equal to 1 V measured using a volt meter and a 500 ohm shunt resistor, and that all findings be mitigated, is too aggressive and essentially unworkable. They argue that 1 V readings are sometimes attributable to neutral currents and induced voltages and are inherently safe and part of a normally functioning electric distribution system. Several industry experts are cited who state that voltages at this level are below the threshold that should be considered dangerous. OSHA Standard 1910.333 is cited, which implies that voltage levels of 25 V or less are not harmful. The Joint Utilities also quote the order from the original Commission decision in January 2005 that the detection of 8 V may not pose an immediate safety hazard. The issue of the additional cost of mitigating or attempting to mitigate these cases is also cited. As an alternative, they propose a new threshold of 4.5 V, which is consistent with current practice for the utilities, and eliminating the 1-4.4 V reporting band from the tabular information captured in Appendix B of the initial proposal. The Lane Foundation is in agreement with the proposed change as presented in the original notice, and recommends that the finding must be mitigated or proven safe by engineering analysis.

The Joint Utilities propose the deletion of the final two sentences of Section 3(h), claiming that the manner in which it is currently constructed is redundant when taken in context with Section 3(i) and Section 3(j), and will lead to confusion for any party seeking guidance from the standards.

Discussion

As stated by Joint Utilities in their formal comments, their current practice is to mitigate any findings at 4.5 V or above. However, Staff reports that Con Edison in actual practice makes a reasonable effort to effectively eliminate the stray voltage condition but does not always achieve a reading of 1 V or less after mitigation on each energized structure that is discovered. Joint Utilities comments regarding neutral currents and induced voltages are reasonable and cannot be dismissed. The possibility that readings less than 1 V may be attributable to these factors and cannot be truly eliminated is legitimate, and in our view this fact must be accounted for. On the other hand, we do believe that findings at this level should not simply be ignored, and that a reasonable effort must be made to address the situation. In our view, the additional safety margin afforded by the revised threshold of 1 V is adequate to justify the more aggressive testing and mitigation requirements. For the sake of pedestrian safety, we will adopt the definition of "Finding" with the 1 V threshold as contained in the original notice, but will add "streetlight" (see Appendix A, page 1, Section 1 paragraph (f)) to confirm the original intent and provide consistency with paragraph 3(b) which requires stray voltage testing on streetlights. However, to acknowledge the possibility that all findings at the 1 V level may not be fully mitigated through corrective actions on the part of the utility, we will define Mitigation as "corrective actions" to "address" rather than "effectively eliminate" the finding (See Appendix A, page 1, Section 1, paragraph (g)). In conjunction with this revision and to enable Staff to track all instances where utilities are unable to fully mitigate findings, we will also require utilities to perform a voltage reading after all mitigation efforts are completed and record that information in Attachment 1 of Appendix A. Additionally, for any case where the voltage reading after mitigation is 1 V or more, the utilities will provide a detailed report on the mitigation efforts undertaken for the particular electric facility or other energized structure (See Appendix a, page 6, Section 9, paragraph (4)).

Upon further examination, it does appear that portions of Section 3, paragraph (h) are redundant in context with subsequent paragraphs contained in this section. The Joint Utilities are correct in their assertion that utility responsibility is fully addressed in the subsequent paragraphs, and we will remove the second sentence from this paragraph. However, we find that the proposal to clarify that mitigation efforts shall be completed on any stray voltage findings is necessary to clarify our intent and should remain (See Appendix A, page 2, Section 3, paragraph (h)).

Additional Testing to Determine the Extent of Stray Voltage

Staff Proposal

Staff proposed adding a new Section 3, paragraph (i), as follows:

> In the event of a finding on an electric facility during stray voltage testing, the utility shall test for stray voltage on all metallic structures that are capable of conducting electricity within a minimum 30 foot radius of the electric facility.

As the safety standards are currently structured, utilities are only required to test their own facilities, plus streetlights that may be owned by other entities. Results from Con Edison's use of the mobile detection vehicle referenced above have demonstrated that this testing regimen does not capture the full extent of the stray voltage issue. Con Edison's testing yields findings that include any structure that is capable of conducting electricity and not just utility assets. The revisions propose that, when a voltage finding is discovered on a facility during manual testing, the utility must widen its test area to include any adjacent metallic structures (handrails, benches, etc.) within 30 ft. of that point, regardless of ownership. Staff proposed this requirement to give a more accurate representation of the magnitude of the problem and the hazards it presents to the public.

Summary of Comments

The Joint Utilities claim that mandating a 30 ft. testing radius will entail safeguarding an area in excess of 2800 square feet, which will be especially difficult to accomplish in urban areas where personnel may have to cross streets several times to complete their tasks. As an alternative, the Joint Utilities propose a 10 ft. testing radius. It also requests that, if this requirement is adopted, that it be restricted to publicly accessible facilities.

The Lane Foundation states that the requirement in the proposal to test metallic structures is inadequate. It claims that, based on 2008 testing data for Con Edison, the most frequently energized object other than streetlights is sidewalks. For that reason, the Lane Foundation proposes that the revisions should not be restricted to metallic structures.

Discussion

The Joint Utilities' point with respect to personnel safety is appropriate. Although it is not the intent of the Safety Standards to sacrifice worker safety for pedestrian safety, we do believe that an increase in the extent of testing is warranted to gain an understanding of and to compile and document the effects of stray voltage conditions on adjacent structures. Although identifying the root cause of the conditions is without question the first priority, identifying other manifestations of these problems is vital to ensuring pedestrian safety. Con Edison's experience utilizing the mobile testing equipment (in densely populated urban environment) and successfully testing all structures in a wide area to pinpoint the root cause of the problem indicates that its protocol can be implemented in other areas of the state, particularly in light of the fact that the testing landscape will be considerably less populated with non-utility structures. Therefore, we will adopt the original recommendation of a 30 ft. testing radius. In addition, it is not the intent of the standards to mandate that utilities test facilities on private property or that are inaccessible to pedestrians, and the standards will be revised to confirm that fact. Again, we will add "streetlights" for consistency with paragraphs 1(f) and 3(b).

The Lane Foundation's comments with respect to non-metallic structures, such as sidewalks, are valid. Con Edison's history utilizing the mobile stray voltage detector indicates that non-metallic structures or surfaces can conduct electricity. As a result, we will revise the standards (See Appendix A, page3, Section 3, paragraph (j)) to eliminate the reference to metallic structures, thus requiring testing of all structures and sidewalks.

Mobile Testing

Summary of Comments

While no formal standards were proposed regarding mobile testing, we did request input from parties on the efficacy of utilizing mobile stray voltage technology on a statewide basis as part of the July 8, 2008 Notice Soliciting Comments.

The Lane Foundation states that the mobile detector is demonstrably superior and has been proven effective in finding energized objects through its use in Con Edison's territory. It goes on to claim that mobile testing is less expensive than manual testing while at the same time yielding a considerably larger pool of potentially dangerous conditions that would have been overlooked through manual testing.

The Joint Utilities report that field demonstrations in areas where overhead distribution is prevalent have indicated that mobile testing is not accurate due to interference created by the overhead facilities. It also contends that there are no specifications that clearly state the required distance from overhead facilities that guarantee accurate results. They also state that there is a significant cost involved for areas outside of New York City, in that mobilization expenditures would be exorbitant relative to the small areas that would be subject to the testing.

CPB recommends that we order the utilities to conduct at least one mobile survey of their underground systems within 90 days, and that the results should be reported to interested parties and used to determine the extent to which the technology should be more broadly used. It believes that it is imperative that the technology be applied statewide to enhance public safety.

Discussion

Con Edison has been utilizing the mobile testing technology extensively for the last several years with good results with thousands of energized objects being identified through its use. In urban areas exclusively comprised of underground distribution systems, the technology is clearly more efficient in identifying potentially hazardous conditions, and Con Edison will continue in its current efforts. As stated earlier, we are accepting the mobile stray voltage detection technology as an alternative to manual testing and meeting the definition of stray voltage testing for compliance with the standards. The Joint Utilities points regarding the limitations of the technology in areas where overhead distribution exists, however, are well taken. To our knowledge, no formal or controlled lab or field testing has been completed to confirm the effects of overhead facilities on the capabilities of the detector. Consequently, we find it is premature to order the use of the mobile detector in all areas of underground distribution on a statewide basis. In a similar vein, we find that CPB's suggestion is impractical given the limitations on the technology and the fact that only one company is able to provide the service at this time. However, recognizing the experience of Con Edison, we believe the other utilities also must employ the technology in specific areas of their systems where the mobile survey is effective. Therefore, we order the utilities[3] to conduct mobile stray voltage detection surveys of their underground electric distribution systems, in appropriate areas[4] of cities with a population of at least 50,000 (based on the results of the 2000 census), during calendar year 2009 to positively identify those areas that can be effectively surveyed. The testing shall continue annually thereafter until further direction from the Commission. This testing will meet the annual requirement under the standards for those areas. Based on the effectiveness and results of these surveys, we will further consider whether we should make additional modifications to the standards.

Repair of Deficiencies Identified by the Inspection Process

Staff Proposal

The inspection component of the Electric Safety Standards (Section 4 of Appendix A) was developed to ensure utilities are checking their facilities for safety and reliability concerns. The original language was focused on establishing procedures and

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[3] Except for Con Edison which we have previously ordered to conduct twelve complete mobile inspection surveys annually.

[4] Areas where interference from overhead facilities is not anticipated.

protocols to perform visual inspection on all facilities on a routine basis. The current standards do not require repair actions in response to inspections, unless stray voltage is found. As a result, Staff recommended expanding the order to require utilities to repair and track activities taken in response to deficiencies found during the inspection process. Additionally, Staff recommended that deficiencies be prioritized or graded based on the expected period for repair at the time of the inspections. To ensure consistency across utilities, Staff recommended that utilities prioritize deficiencies using a common system with defined repair times ranging from one week to two years (defined in greater detail later). Staff also recommended detailed reporting to capture deficiencies by equipment affected (e.g., poles, transformers, cable), priority levels, whether repair actions have been taken, and the timeliness of the repair activities in relation to the assigned priority levels. The initial proposal included the following language in Appendix A:

Section 4:

> (j) As part of the inspection process, deficiencies identified shall be categorized by the time period for the repair based on the severity of the condition. Utilities will prioritize deficiencies by three categories: Level I – repair as soon a possible but not longer than one week, Level II – repair within 6 months of discovery, or Level III – repair within two years. When prioritizing deficiencies, utilities should carefully account for the safety and operational effects should the facility fail prior to repair.
>
> (k) Utilities are expected to permanently repair deficiencies identified by the inspection program within the priority time period established during the inspection.

Section 6:

> (c) Each utility shall develop procedures and protocols to track the permanent repairs made based on inspection data and whether the repairs were made in the appropriate timeframe. An inventory of outstanding repairs by priority level should also be maintained.

Summary of Comments

The Lane Foundation states that the concept of a common prioritization system makes sense, but the criterion used to rank deficiencies are not apparent and should not be left up to the utilities. Con Edison, Central Hudson, and ORU do not support ranking deficiencies with a common priority system and claim that a common system would not account for operational differences between electrical systems. Each of these utilities, however, offers comments on Staff's proposal should a common system be mandated.

With respect to how long companies should have to repair deficiencies, all commentors agree with the one week timeframe for Level I conditions. Con Edison, National Grid, Central Hudson, and ORU, however, propose changing the duration for repair from six months to one year for Level II deficiencies and from two years to three years for Level III deficiencies. NYSEG and RGE also support changing Level II from six months to one year, but were agreeable to the two years for Level III deficiencies. National Grid stated that it would be agreeable to Staff's proposed time periods if the order included expectations for repair completion of 95%, 90%, and 85% for Level I, II, and III, respectively. Con Edison and the Joint Utilities indicated the need to acknowledge that the time requirements should not apply under extraordinary circumstances or when circumstances outside the control of a utility prevent a repair from occurring.

Con Edison proposed the addition of a new ranking, which would defer the repair of the deficiency until it is performed as part of a system upgrade. Con Edison claims that its resources would be stretched to its maximum capacity if the Company has to repair all deficiencies within Staff's recommended two year timeframe while continuing to perform other maintenance and mandated work. By allowing deficiencies to be identified without a specific repair timeframe, Con Edison states it would avoid diverting resources from higher priority work to meet arbitrary repair targets. National Grid also proposed that the time for repair be measured against when a work order is created. National Grid claims that the Level I and II timeframes permits a reasonable amount of time for design and construction only after a work order is created and that requiring repair based on dates other than the work order would put unnecessary administrative burden on its work management system.

Comments received generally support the tracking and reporting on repair activities. The Lane Foundation states that the tracking of repair activities is essential. The Joint Utilities, as well as Con Edison, National Grid, and Central Hudson state that tracking of repairs should not be done on a retroactive basis. Finally, for clarification purposes, the Joint Utilities, Con Edison, and the Lane Foundation suggest modifications to the reporting language and/or structure of Appendix D in the initial proposal.

Discussion

To date, the utilities have been performing inspections as required. Repair activities based on the information collected during these inspections, however, varies. Discussions among Staff and the utilities also determined that a separation exists between the inspection results and the work order systems used for repair. While the utilities seem to be picking up critical and intermediate work, there previously was little assurance that low level conditions would be repaired in a timely manner. We believe that requiring utilities to track and report repair activities will promote the correction of minor problems before they deteriorate or outright fail and decrease the overall soundness of electric systems.

For years, utilities have been using rating systems to grade deficiencies found during inspections. The systems, however, are mostly unique to individual companies and inconsistent with respect to when or if repair actions are required. For instance, four of the six major utilities' rating systems use low numbers to prioritize high level conditions. Central Hudson's and ORU's systems, however, use high numbers to prioritize high level conditions. For these two utilities, the low level numbers are used to capture discrepancies that require no repair action or simply require future monitoring. As a result, continuing with the current priority rating methodologies maintains disorder and makes benchmarking performance across utilities difficult. Therefore, we will adopt a common system for prioritizing repairs as described below. We also agree with comments received that the standards should clarify, to the extent possible, what the priority levels represent.

We agree with Con Edison's comments that the Electric Safety Standards should state that a Level I classification represents an actual or imminent safety hazard to the public or poses a serious and immediate threat to the delivery of power. With respect to repair durations, Level I priorities will be repaired as soon as possible but no longer than one week as stated in the initial proposal. Critical safety hazards present at the time of the inspection shall be guarded until the hazard is mitigated.

Level II priorities represent conditions that are likely to fail prior to the next inspection cycle and represent a threat to safety and/or reliability should a failure occur prior to repair. Based on comments received, we believe it is appropriate that utilities be given up to one year to repair Level II priorities. By extending the time frame contained in the initial proposal from six months to one year, utilities will be able to properly manage repair activities, including obtaining permits and scheduling prearranged outages if needed, in a more effective manner. Given this additional allowance, however, we expect utilities to grade more stringently on deficiencies that are on the border between Level II and Level III.

Staff reported its review of repair work for low level deficiencies indicated a reluctance of the utilities to send crews to repair these conditions individually. For efficiency, utilities would often delay repair work until it was subsumed as part of a larger project or a sufficient amount of other work activities were needed in the vicinity to justify sending a crew to that area. These policies result in significant numbers of deficiencies going unaddressed with some remaining through multiple inspections. Waiting indefinitely for more items to fail before addressing a deficiency is not acceptable.

The standards are being modified to state that deficiencies prioritized as Level III do not present immediate safety or operational concerns and would likely have minimum impact on the safe and reliable delivery of power if they do fail prior to repair. While these deficiencies are not critical, they still need to be addressed. We will adopt the three year timeframe as proposed in the comments to ensure these minor conditions are addressed appropriately. The three years will allow utilities the opportunity to perform the work in a cost efficient manner while still ensuring these repairs are being made.

As previously summarized, Con Edison proposed that a fourth level be used for repairs that would be repaired as part of system upgrades. Under Con Edison's proposal, utilities have the opportunity to indefinitely delay repair of deficiencies that should be addressed by stating the deficiencies will be covered by a system upgrade. We recognize a benefit to noting conditions that exist on the system but do not require repair within five years (i.e., the next required inspection). Therefore, a Level IV will be added to allow utilities to track conditions for monitoring purposes. Evaluation of conditions identified as Level IV should also promote proactive maintenance activities and capital replacement programs.

Given the diversity in equipment, potential safety hazards, and degrees of degradation, it is not practical to list all criteria used to classify discrepancies as part of the Electric Safety Standards. Utility inspectors shall estimate the amount of time that it will take for the damaged equipment to adversely affect public safety or the reliability of the utility system based on training and experience. To help ensure personnel are properly identifying and categorizing deficiencies, we shall require details about training requirements and activities be provided as part of the annual report. Additionally, utilities shall provide Staff a copy of training materials and manuals, and inspection procedures and protocols.

The utilities will also be expected to complete repairs within the designated repair timeframe based on the date of inspection. By doing so, the repair of deficiencies will not be delayed due to processes to communicate information to work order systems. Additionally, we believe that the timeframes identified provide adequate leeway for utilities to complete repairs while managing unanticipated events. Therefore, we see no need to modify the proposal to excuse the timeliness of repairs due to extraordinary circumstances or when circumstances outside the control of a utility prevent a repair from occurring.

Detailed reporting and tracking of the inspection and repair activities is vital to ensuring compliance with the Electric Safety Standards. Additionally, information gathered by this process will be beneficial when evaluating the appropriateness of capital projects, maintenance programs, and associated budgets during rate cases or other reviews. Comments received state that the tracking of repairs should not be done on a retroactive basis or require the utilities to manipulate previously collected data into the common priority levels. While we agree, in part, with the utilities, we also believe that we should not abandon the tracking of deficiencies already identified and not yet repaired. Therefore, beginning in 2009, we will require detailed reporting (Attachment 3 of Appendix A). Utilities are also required to provide historic inspection findings and repair activity on those findings based on priority systems in place at the time of discovery. To the extent practical, the reporting should follow the structure outlined in Attachment 3 of Appendix A. Finally, the language and structure of Attachment 3 of Appendix A will be modified as proposed by the Joint Utilities and the Lane Foundation and to comport with Staff's recommended changes discussed above.

Temporary Repairs

Staff Proposal

In certain circumstances, such as following a vehicular accident or a storm, a temporary repair may be made to restore service or maintain public safety until the utility has the available personnel or materials necessary to make a permanent repair. As part of its monitoring of the inspection programs, Staff reported it witnessed locations where temporary repairs were made to facilities but never followed-up with permanent repairs. Similar instances were also identified by Staff as part of other work activities. Additionally, Staff reports that discussions with the utilities indicate that most did not have effective ways to track temporary repairs. As a result, Staff recommended that utilities be required to develop adequate systems to track temporary repairs on their system for both new repairs and those found during the inspections process.

To ensure timely repairs, Staff recommended that when temporary repair is made or a previously completed temporary repair is discovered during an inspection by the utility, best efforts shall be used to permanently repair the facilities within 45 days. Staff's recommendation indicated that temporary repairs may remain in place for more than 45 days only in extraordinary circumstances, which includes major storms that require significant repair activity. The utility would also be required to perform periodic site visits to monitor the condition of temporary repairs that extend beyond 45 days and justify these exceptions. Finally, Staff recommended the utilities develop procedures and protocols to track temporary repairs and whether permanent repairs were made within 45 days. The initial proposal included the following language of Appendix A:

Section 4:

> <u>(l) When a temporary repair is located during an inspection or made by the company, best efforts shall be used to affect a permanent repair of the facility within 45 days. A temporary repair to the facility may remain in place for more than 45 days only in extraordinary circumstances, which may include major storms that require significant repair activity. In such event, the utility shall periodically perform site visits to monitor the condition of the temporary repair. All exceptions must be identified and justified as part of the reporting requirements under Section 9.</u>

Section 6:

> (d) <u>Each utility shall develop procedures and protocols to track temporary repairs made on the system and whether these locations were permanently repaired within 45 days after making or locating a temporary repair.</u>

<u>Summary of Comments</u>

Con Edison states that the recommendations regarding temporary repairs should be rejected because temporary repairs are necessitated by conditions that are often not in the utilities' control, are constructed to be durable, and the duration of temporary repairs is unpredictable due to the condition and the availability of resources vis-à-vis system operating priorities. Con Edison claims that reporting and justifying temporary repairs that extend beyond the 45 day is unreasonably burdensome and intrusive on the Company's discretion to manage its operations and resources. Con Edison also states that programs within its Reliability Performance Mechanism (RPM) already account for temporary repairs that involve public safety and the 45 day requirement is unreasonable and arbitrary compared to existing RPM requirements.

The Joint Utilities proposes extending the time to complete permanent repairs from 45 days to six months to allow time to plan a permanent repair, obtain equipment and/or permits, and schedule the repair. Con Edison states that if a requirement for temporary repairs is established, it should only apply to conditions that present a safety hazard or an impending impact on reliability and that utilities be given at least six months to perform a permanent repair. Both the Joint Utilities and Con Edison indicate that utilities should be allotted a time period to implement a system to accurately track temporary repairs.

Discussion

While it is clear that temporary repairs must be completed in some cases to restore service to customers or stabilize damaged facilities, utilities should not rely upon these measures for extended and indefinite periods of time. It is unsettling that most utilities do not have effective ways to track temporary repairs. Given Staff's findings and the lack of awareness about temporary repairs that exist on electric systems, we believe it is appropriate to establish requirements regarding temporary repairs as part of the standards.

Comments received raise valid concerns with respect to a utility being able to plan a permanent repair, obtain equipment and/or permits, and schedule the repair in an efficient manner. Con Edison refers to its RPM as a basis for changing the timeframe to perform temporary repairs. Con Edison's RPM programs require permanent repairs to at least 90% of the facilities anywhere from 30 to 90 days, with a six month requirement to finalize all temporary repairs. Con Edison's RPM should not be viewed as a substitute for the standards regarding temporary repairs. The RPM was designed for issues specific to Con Edison and are not necessarily reflective of statewide concerns. Additionally, the percentages and timeframes specified in Con Edison's RPM were established at levels to impute negative revenue adjustments for unacceptable performance.

To alleviate concerns about planning, scheduling and material acquisitions, we will change the allowed timeframe for permanent repairs from Staff's recommended 45 days to 90 days (See Appendix A, page 4, Section 4, paragraph (l)). We believe that a 90-day period is adequate, particularly because the standards already allow for extended repair time given extraordinary circumstances, such as significant repair activity following a major storm. Given that many situations where temporary repairs exist longer than 90 days will have a common cause (e.g. major storm), we do not agree that reporting and justifying these situations will be burdensome.

Implementation Period for Changes to the Visual Inspection Program

Summary of Comments

The Joint Utilities, Con Edison, and ORU indicate that utilities should be allotted a time period to implement systems to make repairs in response to inspection findings and/or systems to accurately track temporary repairs and their permanent repair. Con Edison offers that the repair requirements should not apply until January 1, 2010, which coincides with the beginning of the second five-year inspection cycle.

Discussion

While we understand that process changes will be needed to comply with the revised recommendations, most of the changes are to correct sizable gaps and are overdue. Delaying the application of such changes merely to allow utilities to develop automated systems is inappropriate. We are confident that utilities have the ability to either develop systems timely or establish systems to be used on a temporary basis until permanent solutions are determined. Utilities may also restructure the use of current IT systems to bridge the gap until they develop and implement new systems. Therefore, we reject the proposal to delay the application of the revised standards until 2010.

Stray Voltage Testing and Inspection Cycles

Staff Proposal

Currently utilities have one year to complete all stray voltage testing and visually inspect at least 20% of their facilities. The 12-month cycle is from December 1 to November 30 the following year. The utilities are also required to file an annual report by January 15th of each year documenting their findings. Staff's initial proposal was to change the annual testing and inspection testing to a calendar year and modify the due date of the annual report to February 15 of each year.

Discussion

The non-calendar cycle has resulted in misinterpretation and inconsistent or conflicting data in both Staff reports and those produced by utilities. On several occasions, Staff reported it has had to reconcile discrepancies or provide documentation supporting its computations. To avoid future confusion, we shall modify the testing and inspection requirements to be performed on a calendar year basis and require the annual report be moved to February 15 to account for the shift in the cycle end date. Given the latest 12-month cycle ended in November 2008, however, annual reports for this cycle shall be submitted by January 15, 2009, as previously required. Stray voltage tests and inspections performed in the month of December 2008 may be applied to the 2009 calendar cycle. The annual report for the 2009 calendar cycle, however, shall specifically segregate the December 2008 results.

Quality Assurance

Staff Proposal

Section 5 of Appendix A requires utilities to have a quality assurance program to ensure compliance with the program. As part of the initial proposal, Staff recommended that the quality assurance program be independent of the stray voltage testing and inspections programs.

Discussion

Good quality assurance programs provides confidence that all activities are performed satisfactory and in compliance with the requirements. The quality assurance programs used to monitor stray voltage testing and inspections have been improving and evolving since the inception of the Electric Safety Standards. Staff reports that it has been working with the utilities to separate the personnel and departments responsible for performing the stray voltage testing and inspections from those who perform the quality assurance activities. This effort has resulted in increased confidence that substandard performances are being identified and rectified. As a result, we shall adopt Staff's proposal to require independence in the quality assurance programs. The management and personnel performing quality assurance activities shall be separate from those performing required stray voltage testing and inspection activities. Additionally, we believe it is appropriate to expand the order at this time to specifically detail areas that are to be addressed by the quality assurance programs for clarification purposes.

With regard to inspections, we shall require the quality assurance program be developed to ensure that inspections are being performed on all facilities and that deficiencies are being properly identified and categorized for repair. The quality assurance program should also verify that permanent repairs are made in response to inspections performed and the timeliness of the repair. The results of the quality assurance programs shall be provided in the annual reports.

CONCLUSION

The requirements of the Electric Safety Standards have resulted in the identification of locations with sizable stray voltage levels where mitigation was necessary to maintain public safety, and the standards remain an effective means to ensure the safe and reliable operation of the electric system. Through experience and lessons learned over the past three years, several areas have been identified in the standards that require clarification and elaboration. These modifications to the Electric Safety Standards are made after considering comments submitted and balancing the interests and needs of the utilities, their ratepayers, and the public.

The Commission orders:

1. The standards discussed in the body of this Order and detailed in Appendix A are adopted.

2. The November 30, 2006 petition filed by ORU seeking a waiver from performing stray voltage testing on distribution and transmission facilities annually is denied.

3. All utilities, with the exception of Con Edison, shall complete an initial mobile stray voltage detection survey of their underground electric distribution systems, in appropriate areas of cities with a population of at least 50,000 (based on the results of the 2000 census), during calendar year 2009 to positively identify those areas that can be effectively surveyed, and annually thereafter until further Commission action.

4. Con Edison shall continue to conduct twelve complete mobile stray voltage surveys annually until directed otherwise by the Commission.

5. This proceeding is continued.

By the Commission,

(SIGNED) JACLYN A. BRILLING
Secretary

ELECTRIC SAFETY STANDARDS

SECTION 1: DEFINITIONS

(a) Utilities – The term "utilities" includes all investor-owned and municipal electric corporations subject to the Commission's jurisdiction that own or operate transmission or distribution facilities, whether fully or lightly regulated. As appropriate, the term also includes companies subject to our jurisdiction that own or operate electric generating facilities within the State, whether fully or lightly regulated.

(b) Electric facilities – The term “electric facilities” means and refers to all electric plant, as that term is defined in Public Service Law §2(12), that is used to modulate, transmit, and/or distribute electricity, or is related to its modulation, transmission, and/or distribution. The term “overhead facilities” generally includes the electric facilities that are part of a utility’s overhead distribution system (e.g., the system that serves rural areas and includes towers, poles, and aerial cable and conductors). The term “underground facilities” generally includes the electric facilities that are part of a utility’s underground distribution system (e.g., the system that serves urban areas and includes manholes, service boxes, and underground cable and conductors).

(c) Stray Voltage –The term “stray voltage” means voltage conditions on electric facilities that should not ordinarily exist. These conditions may be due to one or more factors, including, but not limited to, damaged cables, deteriorated, frayed or missing insulation, improper maintenance, or improper installation.

(d) Streetlights – The term “streetlights” means and includes utility- and municipal owned streetlights located on, along, or adjacent to public thoroughfares and areas and traffic signal poles and devices; it does not include privately-owned light fixtures, such as those located in private parking lots.

(e) Stray Voltage Testing – The process of checking an electric facility for stray voltage using a device capable of reliably detecting and audibly and/or visually signaling voltage in the range of 6 to 600 volts.

(f) Findings – Any confirmed voltage reading on an electric facility or streetlight greater than or equal to 1V measured using a volt meter and a 500 ohm shunt resistor.

(g) Mitigation –Corrective actions performed by the utility to address the stray voltage findings.

(h) Inspection – A careful and critical examination of an electric facility by a qualified individual to determine the condition of the facility and the potential for it to cause or lead to safety hazards or adverse effects on reliability.

SECTION 2: NATIONAL ELECTRIC SAFETY CODE COMPLIANCE

(a) The installation, construction, maintenance, and operation of electric facilities shall comply with the latest version of the National Electric Safety Code (NESC), except where a utility's practices, procedures, and protocols are more stringent.

(b) Utilities are not required to retrofit their existing facilities to comply with the latest version of the NESC, unless the latest version of the NESC requires a retrofit.

(c) To the extent that projects currently being constructed do not comply with the NESC or a utility's more stringent standards, exemption from compliance will be considered on a case-by-case basis.

(d) If a utility believes that it cannot satisfy any provision of the NESC for a valid technical reason, it may petition the Commission for an exemption from compliance with that provision.

SECTION 3: STRAY VOLTAGE TESTING

(a) Stray voltage testing shall be conducted on all utility facilities that are capable of conducting electricity and are publicly accessible. Testing is not required on customer meters and customer-owned facilities, except municipal-owned streetlights.

(b) Stray voltage testing shall be conducted on all streetlights.

(c) For underground electric facilities that are publicly accessible, including, but not limited to, manholes, service boxes, and transformer vaults, stray voltage testing shall be conducted on the exposed surfaces of the facilities.

(d) Stray voltage testing of streetlights shall be conducted when the light is activated (i.e., at night).

(e) Stray voltage testing shall be conducted on an annual basis.

(f) If a streetlight to which a utility provides service is owned by another entity, and that entity conducts stray voltage testing meeting these safety standards, the utility may substitute that testing program for its own, provided the utility can certify the other entity's results.

(g) All equipment used for stray voltage testing must be certified by an independent test laboratory as being able to reliably detect voltages of 6 to 600 volts.

(h) Any facility for which a voltage finding is discovered shall be guarded by the utility immediately and continuously until the utility has performed mitigation and made the area safe. Mitigation shall be completed on any stray voltage findings.

(i) In instances where a stray voltage finding is determined to be caused by customer-owned equipment, the area must be immediately made safe. The utility shall immediately notify the customer or a responsible person associated with the premises or the customer-owned facility of the unsafe condition and the need for the customer to arrange for a permanent repair to the customer's equipment.

(j) In the event of a finding on an electric facility or streetlight during stray voltage testing, the utility shall test for stray voltage on all publicly accessible structures and sidewalks within a minimum 30 foot radius of the electric facility or streetlight.

(k) In each instance where stray voltage is determined to be caused by a utility-owned facility, best efforts shall be used to effect a permanent repair of the facility as soon as possible, but not later than 45 days after discovery of the stray voltage condition. A temporary repair to the facility may remain in place for more than 45 days only in extraordinary circumstances, and in such event the utility shall periodically perform site visits the monitor the condition of the temporary repair. All exceptions must be identified and justified as part of the reporting requirements under Section 9.

SECTION 4: INSPECTIONS

(a) Inspections shall include, at a minimum, visual examination of towers, poles, guy wires, risers, overhead cables and conductors, transformers, breakers, switches, and other aboveground equipment and facilities, and of the interior of manholes, service boxes, vaults, and other underground structures. Where debris or water is found in an underground structure, it must be removed before commencing the inspection so that all of the facilities in the structure, and the structure itself, may be fully inspected.

(b) Inspection of equipment should be performed in a manner that allows the inspector to examine its components, except those that are ordinarily encased in sealed compartments. Utilities need not perform destructive testing as part of this inspection program, except as otherwise required by their more intensive inspection procedures.

(c) When a visual inspection indicates the need for a more intensive examination, the utilities shall perform infrared testing and/or other inspection procedures.

(d) When an inspection reveals a hazardous condition or other problem, whether related to stray voltage or otherwise, the utility must make all repairs necessary to eliminate the condition.

(e) All electric facilities shall be inspected at least once every five years. Certain facilities may warrant shorter inspection cycles.

(f) Each utility shall develop and implement a formal inspection program that complies with these safety standards.

(g) Inspections conducted during routine maintenance and other work not directly related to the inspection program may count as an inspection visit, provided that the inspection is performed using the same safety and reliability criteria and to the same extent as would otherwise be required under these standards. Inspections occurring during these field visits must be properly documented and certified.

(h) This inspection requirement is intended to complement, not supplant, the inspections any utility already performs; to the extent a utility's inspection program is broader or more intensive than the program described herein, the utility should continue to follow its own program.

(i) The testing and inspection programs may be combined, where practical and feasible, provided the synergy satisfies all the requirements contained within these safety standards.

(j) As part of the inspection process, deficiencies identified shall be categorized by the time period for the repair based on the severity of the condition. When prioritizing deficiencies, utilities should carefully account for the safety and operational effects should the facility fail prior to repair. Utilities will prioritize deficiencies by three categories:

> Level I – repair as soon a possible but not longer than one week. A Level I deficiency is an actual or imminent safety hazard to the public or poses a serious and immediate threat to the delivery of power. Critical safety hazards present at the time of the inspection shall be guarded until the hazard is mitigated.
>
> Level II – repair within one year. A Level II deficiency is likely to fail prior to the next inspection cycle and represent a threat to safety and/or reliability should a failure occur prior to repair.
>
> Level III – repair within three years. A Level III deficiency does not present immediate safety or operational concerns and would likely have minimum impact on the safe and reliable delivery of power if it does fail prior to repair.
>
> Level IV – condition found but repairs not needed at this time. Level IV is used to track atypical conditions that do not require repair within a five year timeframe. This level should be used for future monitoring purposes and planning proactive maintenance activities.

(k) Utilities are expected to permanently repair deficiencies identified by the inspection program within the priority time period established for its classification. All repair time periods are based on the initial date of discovery.

(l) When a temporary repair is located during an inspection or made by the company, best efforts shall be used to affect a permanent repair of the facility within 90 days. A temporary repair to the facility may remain in place for more than 90 days only in extraordinary circumstances, which may include major storms that require significant repair activity. In such event, the utility shall periodically perform site visits to monitor the condition of the temporary repair. All exceptions must be identified and justified as part of the reporting requirements under Section 9.

SECTION 5: QUALITY ASSURANCE

Each utility shall develop a quality assurance program to ensure timely and proper compliance with these safety standards. The quality assurance program shall be independent of the stray voltage testing and visual inspection programs. The management and personnel performing quality assurance activities shall be separate from those performing the required stray voltage testing and inspections.

(a) With regard to inspections, the quality assurance program should ensure that inspections are being performed on all facilities and that deficiencies are being properly identified and categorized for repair. The program should also verify that permanent repairs are made and the timeliness of the repairs.

SECTION 6: RECORDKEEPING

(a) Each utility shall develop procedures and protocols to track the stray voltage testing dates and results for each electric facility.

(b) Each utility shall develop procedures and protocols to track the inspection dates and results for each electric facility.

(c) Each utility shall develop procedures and protocols to track the permanent repairs made based on inspection data and whether the repairs were made in the appropriate timeframe. An inventory of outstanding repairs by priority level should also be maintained.

(d) Each utility shall develop procedures and protocols to track temporary repairs made on the system and whether these locations were permanently repaired within 90 days after making or locating a temporary repair.

(e) These records shall be kept in a manner that is readily accessible and searchable, continuously updated, and subject to review and audit by Staff and the Commission.

SECTION 7: CERTIFICATION

(a) Written certification of the completion and results of every stray voltage test and inspection undertaken and that all unsafe conditions identified have been remediated shall be made by an appropriate utility employee.

(b) The President or officer of each utility with direct responsibility for overseeing stray voltage testing shall provide an annual certification to the Commission that the utility has tested all of its publicly accessible electric facilities and all streetlights.

© The President or officer of each utility with direct responsibility for overseeing facility inspections shall provide an annual certification to the Commission that the utility is in compliance with its inspection program and has inspected the requisite number of electric facilities. Additionally, at the end of five-year inspection cycle, the officer shall certify that all of the utility's electric facilities have been inspected at least once.

(d) Each utility shall maintain its written certifications and other documentary proof of its testing and inspections at its corporate office located within the State of New York. These documents shall be available to the public for review upon request and without conditions.

SECTION 8: NOTIFICATION REQUIREMENTS

Each utility shall comply with the Event Notification Requirements attached hereto.

SECTION 9: REPORTING REQUIREMENTS

(a) Each utility shall file a comprehensive report by February 15 each year that:

1. details the results of stray voltage tests and inspections conducted over the 12-month period ending December 31 of the prior calendar year;

2. addresses the performance mechanism specified in Section 10;

3. contains the certifications described in Section 7;

4. contains a breakdown of the voltage findings in a tabular format as detailed in Attachment 1; for all findings that result in a reading of 1 V or more after completion of mitigation efforts, the utilities shall provide a detailed report on those efforts;

5. contains a breakdown of the shock reports received from the public as detailed in Attachment 2;

6. discusses the analyses undertaken on the causes of stray voltage within the utility's electric system, the conclusions drawn there from, the preventative and remedial measures identified, and the utility's plans to implement those measures;

7. describes the priority levels used to gauge the severity of a deficiency, including repair timeframes, and details the requirements for training personnel to properly identify and categorize deficiencies**;**

8. contains a breakdown of facilities to be inspected, unique inspection conducted per year, and the cumulative number of unique inspections conducted to meet the five year requirement;

9. contains a breakdown of the deficiencies found, permanent repair actions taken by year, whether the repair was completed within the required timeframe, and the number of

deficiencies awaiting repair. The information should be provided on a yearly basis by priority level and by equipment groupings as detailed in Attachment 3;

10. contains a review and analysis of the inspection results. Areas of concern should be identified along with remedial actions or future plans to alleviate inadequacies in current programs or assets;

11. describes the quality assurance program and provides the results from quality assurance activities conducted during the year; and

12. Includes all other information that is pertinent to the issues addressed by the safety standards.

SECTION 10: PERFORMANCE MECHANISM

(a) The annual performance target for stray voltage testing shall be 100% of all electric facilities and streetlights that must be tested. Facilities that are inaccessible and which pose no risk to public health and safety will not be considered in the determination of whether the target has been achieved.

(b) Failure to achieve the annual performance target for stray voltage testing shall result in a rate adjustment of 75 basis points.

(c) The annual performance target for inspections shall be based on the percentage of the average number of electric facilities that must be inspected each year in order to comply with the five-year inspection cycle. That is, the target is based on the one-fifth of the total number of the utility’s electric facilities. The specific targets will be as follows:

First year inspection goal 85% of annual target

Second year inspection goal 90% of annual target

Annual inspection goal thereafter 95% of annual target

Fifth year inspection goal 100% of all facilities to be inspected

(d) Failure to achieve the annual performance target for inspections shall result in a rate adjustment of 75 basis points.

ATTACHMENT 1

Summary of Voltage Findings

	Initial Readings				Readings after Mitigation		
	1-4.4 V	4.5-24.9 V	> 25 V	Totals	< 1 V	1 V-4.4 V	>4.5 V
Distribution Facilities							
Pole							
Ground							
Guy							
Riser							
Other							
Underground Facilities							
Service Box							
Manhole							
Padmount Switchgear							
Padmount Transformer							
Vault – Cover/Door							
Pedestal							
Other							
Street Lights / Traffic Signals							
Metal Street Light Pole							
Traffic Signal Pole							
Control Box							
Pedestrian Crossing Pole							
Other							
Substation Fences							
Fence							
Other							
Transmission (Total)							
Lattice Tower							
Pole							
Ground							
Guy							
Other							
Miscellaneous Facilities							
Sidewalk							
Gate/Fence/Awning							
Traffic Sign							
Scaffolding							
Bus Shelter							
Fire Hydrant							
Phone Booth							
Traffic Control Box							
Water Pipe							
Riser							
Other							

ATTACHMENT 2

Summary of Shock Reports from the Public

I.	**Total shock calls received:**	
	Unsubstantiated	
	Normally Energized Equipment	
	Stray Voltage:	
	Person	
	Animal	
II.	**Injuries Sustained/ Medical Attention Received**	
	Person	
	Animal	
V.	**Voltage Source:**	
	Utility Responsibility	
	Issue with primary, joint, or transformer	
	Secondary Joint (Crab)	
	SL Service Line	
	Abandoned SL service line	
	Defective service line	
	Abandoned service line	
	OH Secondary	
	OH Service	
	OH Service neutral	
	Pole	
	Riser	
	Other	
	Customer Responsibility	
	Contractor Damage	
	Customer Equipment/Wiring	
	Other Utility/Gov't Agency Responsibility	
	SL Base Connection	
	SL Internal Wiring or Light Fixture	
	Overhead Equipment	
VI.	**Voltage Range:**	
	1.0V to 4.4V	
	4.5V to 24.9V	
	25V and above	

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Distribution															
Overhead Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Poles															
Pole Condition															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Grounding System															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Anchors/Guy Wire															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Cross Arm/Bracing															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Riser															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Distribution (cont.)

Overhead Facilities	2009			2010			2011			2012			2013		
Priority Level	I	II	III	I	II	III	I	II	III	I	II	III	I	II	III
Repair Expected	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years
Conductors															
Primary Wire/Broken Ties															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Secondary Wire															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Neutral															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Insulators															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Pole Equipment															
Transformers															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Cutouts															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Distribution (cont.)															
Overhead Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Lightning Arrestors															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Other Equipment															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Miscellaneous															
Trimming Related															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Other															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Overhead Facilities Total															
Total															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Transmission															
Transmission Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Towers/Poles															
Steel Towers															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Poles															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Anchors/Guy Wire															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Crossarm/Brace															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Grounding System															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Transmission (cont.)															
Transmission Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Conductors															
Cable															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Static/Neutral															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Insulators															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Miscellaneous															
Right of Way Condition															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Other															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Transmission FacilitiesTotal															
Total															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Underground

Underground Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Underground Structures															
Damaged Cover															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Damaged Structure															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Congested Structure															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Damaged Equipment															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Underground (cont.)

Underground Facilities	2009			2010			2011			2012			2013		
Priority Level	I	II	III	I	II	III	I	II	III	I	II	III	I	II	III
Repair Expected	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years	Within 1 week	Within 1 year	Within 3 years
Conductors															
Primary Cable															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Secondary Cable															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Neutral Cable															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Racking Needed															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Miscellaneous															
Other															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Underground Facilities Total															
Total															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Pad Mount Transformers															
Pad Mount Transformers	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Pad Mount Tansformers															
Damaged Structure															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Damaged Equipment															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Cable Condition															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Oil Leak															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Off Pad															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Lock/Latch/Penta															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Pad Mount Transformers (cont.)															
Pad Mount Transformers	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Miscellaneous															
Other															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Pad Mount Total															
Total															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Streetlights															
Overhead Facilities	**2009**			**2010**			**2011**			**2012**			**2013**		
Priority Level	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**	**I**	**II**	**III**
Repair Expected	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**	**Within 1 week**	**Within 1 year**	**Within 3 years**
Streetlight															
Base/Standard/Light															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Handhole/Service Box															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Service/Internal Wiring															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Access Cover															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Miscellaneous															
Other															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															
Streetlight Total															
Total															
Number of Deficiencies															
Repaired in Time Frame															
Repaired - Overdue															
Not Repaired - Not Due															
Not Repaired - Overdue															

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Level IV Conditons

Overhead Facilities	2009		2010		2011		2012		2013	
	Number of Conditions Found	Number of Conditions Repaired	Number of Conditions Found	Number of Conditions Repaired	Number of Conditions Found	Number of Conditions Repaired	Number of Conditions Found	Number of Conditions Repaired	Number of Conditions Found	Number of Conditions Repaired
Overhead Facilities										
Pole Condition										
Pole Condition										
Grounding System										
Anchors/Guy Wire										
Cross Arm/Bracing										
Riser										
Conductors										
Primary Wire/Broken Ties										
Secondary Wire										
Neutral										
Insulators										
Pole Equipment										
Transformers										
Cutouts										
Lightning Arrestors										
Other Equipment										
Miscellaneous										
Trimming Related										
Other										
Overhead Facilities Total										
Transmission Facilities										
Towers/Poles										
Steel Towers										
Poles										
Anchors/Guy Wire										
Crossarm/Brace										
Grounding System										
Conductors										
Cable										
Static/Neutral										
Insulators										
Miscellaneous										
Right of Way Condition										
Other										
Transmission Facilities Total										

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process - Level IV Conditons (cont.)										
Overhead Facilities	**2009**		**2010**		**2011**		**2012**		**2013**	
	Number of Conditions Found	**Number of Conditions Repaired**	**Number of Conditions Found**	**Number of Conditions Repaired**	**Number of Conditions Found**	**Number of Conditions Repaired**	**Number of Conditions Found**	**Number of Conditions Repaired**	**Number of Conditions Found**	**Number of Conditions Repaired**
Underground Facilities										
Underground Structures										
Damaged Cover										
Damaged Structure										
Congested Structure										
Damaged Equipment										
Conductors										
Primary Cable										
Secondary Cable										
Neutral Cable										
Racking Needed										
Miscellaneous										
Other										
Underground Facilities Total										
Pad Mount Transformers										
Underground Structures										
Damaged Structure										
Damaged Equipment										
Damaged Cable										
Oil Leak										
Off Pad										
Lock/Latch/Penta										
Miscellaneous										
Other										
Pad Mount Transformer Total										
Streetlights										
Streetlight										
Base/Standard/Light										
Handhole/Service Box										
Service/Internal Wiring										
Access Cover										
Miscellaneous										
Other										
Streetlight Total										
Total Level IV Conditions										
Overall Total										

ATTACHMENT 3

Summary of Deficiencies and Repair Activity Resulting from the Inspection Process							
Year	**Prority Level / Repair Expected**		**Deficiencies Found (Total)**	**Repaired In Time Frame**	**Repaired - Overdue**	**Not Repaired - Not Due**	**Not Repaired - Overdue**
2009	I	Within 1 week					
	II	Within 1 year					
	III	Within 3 years					
	IV	N/A					
2010	I	Within 1 week					
	II	Within 1 year					
	III	Within 3 years					
	IV	N/A					
2011	I	Within 1 week					
	II	Within 1 year					
	III	Within 3 years					
	IV	N/A					
2012	I	Within 1 week					
	II	Within 1 year					
	III	Within 3 years					
	IV	N/A					
2013	I	Within 1 week					
	II	Within 1 year					
	III	Within 3 years					
	IV	N/A					

EVENT NOTIFICATION REQUIREMENTS

ALL NOTIFICATIONS SHALL BE MADE WITHIN ONE HOUR OF AN INCIDENT OR EVENT UNLESS OTHERWISE SPECIFIED

I. System Control - Reports of Impending Emergencies, Emergencies, and Load Curtailment

A. Requests for curtailed electric use, voltage reductions, and load shedding initiated to maintain the adequacy of the electric system and significant bulk supply outages or accidents of consequence are to be reported to the Office of Electric, Gas and Water. The specific items to be brought to the Office's attention are as follows:

1. Any decision to issue a request for customer reduction in use of electricity. The Office of Electric, Gas and Water is to be notified at the time of decision to issue any such request.

2. Any action to maintain the adequacy of the bulk electric system by reducing firm customer loads by voltage reductions, manual switching, operation of automatic load shedding devices, or any other means. The Office of Electric, Gas and Water is to be notified at the time of decision to take such action.

3. Any bulk supply outage that has, or could have, a significant impact on the utility's electric system or the state-wide system.

B. The following information is to be included in the reports:

1. For Items I.A.1. and I.A.2., the utility shall provide the approximate area(s) affected, the time(s) of the action, the time(s) and/or an estimate of the time(s) of restoration of normal service (or cancellation of a customer request), an estimate of the amount of load reduction expected or load interrupted, and the number of customers affected if load is interrupted.

2. For Item I.A.3., the utility shall provide a description of the incident and events leading to its occurrence, the time of occurrence, the system(s) affected, and an evaluation of the effect on the system(s).

II. Loss of Electric Service

A. Written reports of electric service interruptions of five minutes or more are required by 16 NYCRR Part 97. Such reports are to be prepared in accordance with the regulations and submitted to the Office of Electric, Gas and Water.

B. Additionally, notice is to be made for each of the following events:

1. Loss of electric service to 5,000 customers or more lasting 30 minutes or more.

2. Any loss of a distribution system network.

C. Notice of these events occurring after business hours shall be made no later than 8:30 a.m. of the next business day, unless they receive significant media attention, in which case notice shall be provided within one hour.

D. The following information should be provided in the notice:

1. The approximate territory affected.

2. The date and time of the incident causing the interruption.

3. The expected duration of the interruption.

4. If restored at the time of the call, the date and time of restoration.

5. The number of customers affected and amount of load involved.

6. A listing of any critical services affected.

7. A description of the incident and its cause.

8. Any follow-up actions planned.

III. Reports of Personal Injury Accidents

A. Written and telephone notification of electric system personal injury accidents and deaths are required by 16 NYCRR Part 125. This requirement applies to all electric system accidents that result in injury or death to a non-employee and/or inpatient hospitalization or death to an employee or contractor employed by the utility, including accidents that occur at generating plants.

B. All written and telephone reports are to be made in accordance with the regulations and the following requirements and submitted to the Office of Electric, Gas and Water.

1. Reports for accidents, except those involving a fatality or major media attention, occurring after business hours shall be made no later than 8:30 a.m. of the next business day.

2. Written reports shall be made using the Department's standard form and may be submitted via e-mail or fax.

3. Telephone reports should include the following information:

a. The location of the accident.

b. The date and time of the accident.

c. Whether or not the injured party is a utility employee or contractor.

d. A description of the injuries sustained and the status of the injured party.

e. A description of the accident and its cause.

f. The time the utility received notification of the incident.

g. The time the first utility personnel arrived at the scene.

h. The time qualified utility personnel arrived at the scene (i.e., personnel capable of addressing any safety hazard).

i. Whether response operations were affected until utility personnel arrived.

IV. Report of Shock Incidents and Motor Vehicle Accidents

A. All electric shock incidents that do not involve personal injuries shall also be reported.

B. Electric shock incidents involving animals shall be reported.

C. Motor vehicle accidents involving utility facilities and/or utilities vehicles in which there is a personal injury shall be reported.

D. All reports of these incidents are to be submitted to the Office of Electric, Gas and Water. The Director of the Office of Electric, Gas and Water shall prescribe the manner in which the reports are to be provided.

E. Reports for incidents occurring after business hours shall be made no later than 8:30 a.m. of the next business day.

F. The reports should include the following information:

1. The location of the incident.

2. The date and time of the incident.

3. Whether or not the party who was shocked or injured, as appropriate, is a utility employee or contractor.

4. A description of the condition of the affected party, and, as appropriate, of the injuries sustained.

5. A description of the incident and its cause.

6. The time the utility received notification of the incident.

7. The time the first utility personnel arrived at the scene.

8. The time qualified utility personnel arrived at the scene (i.e., personnel capable of addressing any safety hazard). ___

9. Whether response operations were affected until utility personnel arrived.

V. Unusual Events

A. Major Events

Immediate notification is to be made for major events associated with a utility's electric system that will likely result in considerable media attention. Examples of major events include, but are not limited to, load shedding, catastrophic storm emergencies, boiler explosions, or nuclear radiation releases.

Immediate notification is also to be made whenever a utility's corporate emergency command center (e.g., storm center) becomes operational.

B. Media Attention

Incidents involving utility facilities that are likely to receive attention from the news media are to be reported immediately. Examples of such events include, but are not limited to, fires, manhole explosions, equipment damage of $1 million or more, and nuclear plant incidents.

VI. Manner of Notification

Except where otherwise noted above, the Director of the Office of Electric, Gas and Water shall prescribe the manner in which notice to Staff is to be provided.