BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

Consolidated Edison Company of New York, Inc.

Case 09-E-0428

August 2009

Prepared Redacted Exhibits of:

Staff Infrastructure Investment Panel

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Exhibit___(SIIP-1)
(Redacted)

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Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS5
Date of Response: 06/09/2009
Responding Witness: IIP

Question No. :20
Subject: Load Forecasting - Fully explain how the Company determines the accuracy of recent load forecasts. Additionally, explain how the Company identifies the reasons for significant variances with actual results.

Response:
At the conclusion of each summer period, Con Edison evaluates the daily weekday service area peak load experience and adjusts the load to a specific weather reference, referred to as Temperature Variable ("TV").

For planning purposes, the TV represents a condition that is expected to occur only in one of every three years. CECONY's TV is 86º (wet-bulb/dry-bulb combination) and is currently based on the average of data from the National Weather Service stations at Central Park and LaGuardia airport.

The summer daily load evaluation process includes the "rebuilding" of actual peak loads to compensate for the occurrence of load mitigation, such as outages, voltage reductions, customer appeals, and dramatic weather pattern shifting. Regression analyses are then utilized to determine the weather adjusted system load that serves as the base point to gauge the accuracy of the pre-summer forecast.

Several components go into a forecast, including the impact of private non-manufacturing employment, growth in gross domestic product, growth in households, impact of household occupancy, new construction activities, the completion of buildings now under construction, and the occupancy of existing vacant space.

Significant variances between forecasted load and actual load experience are investigated by reviewing the most current economic and Company-specific indicators, such as completed construction activity, and air conditioning and appliance saturation and use over the summer. The former includes (1) accessing our Customer Information System (CIS) to determine actual demand usage, and (2) tracking project delays or cancellations through Energy Services. The latter includes assessing the results from surveys conducted over the summer and evaluating the impact on the residential load based on customer's responses.

Con Edison has recognized the importance of forecast accuracy, and as such established a Key Performance Indicator linked to network area forecasts.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS5
Date of Response: 06/09/2009
Responding Witness: IIP

Question No. :29
Subject: System Planning - Fully explain how the Company prioritizes projects in its system planning process.

Response:
Distribution System
The Chief Distribution Engineer, working with the Regional Electric Operations organizations, reviews proposed programs/projects to determine prioritization for funding projects in the Electric Distribution (ED-1) capital budget, and ensures the capital projects and programs are aligned with the overall Corporate priorities as follows:

Public and Employee Safety Programs:
The capital expenditures in this category address public and employee safety initiatives. These include such items as the 5-year safety / service / secondary inspection program.

Emergency Management Programs:
The capital expenditures in this category are caused by failed components of the distribution system that must be replaced to meet design standards and restore service to customers. These include such items as replacement of primary cable sections to restore an open automatic feeder, installation of conduit to replace an obstructed duct containing a failed section of primary cable, replacement of a damaged pole, or replacement of overhead wire due to storm damage or other causes.

Regulatory Compliance/Environmental Excellence Programs
These programs include items such as interference agreements; State law and certain of the Company's franchise agreements require the Company to relocate or support in place facilities that interfere with public improvement projects.

Infrastructure Programs that address increased customer demand
These programs include items which address increased customer demand such as, but not limited to new business, area substation load relief, primary feeder relief, non-network feeder relief, and transformer relief.

System and Component Performance Programs

These programs include items which address system reinforcement and reliability, such as but not limited to primary cable and splices, network transformers, secondary systems, and distribution unit substations and their associated feeders. System reinforcement projects and programs are reviewed to determine which take priority based on their impact on overall system performance and the associated cost to achieve that improvement.

Strategic IT Enhancement Programs

These programs include items such as, but not limited to, transformer remote monitoring, integrated system models, grid optimization, and outage management systems, and tools to engineering and operations.

During the Electric Distribution budgeting process, the Electric Operations regions prepare and submit requests for capital funding for system reinforcement projects supported by a list of all projects showing the estimated cost, the magnitude of the overload or undervoltage, percent loading, and anticipated improvement after relief is completed.

For reliability programs, the Electric Operations regions provide a description of the program, type of system improvement, magnitude of the improvement, number of units associated with each program, and estimated cost. Non-network programs are prioritized based on where the greatest impact on system performance for the dollars expended can be achieved.

Distribution Engineering reviews the Regions' submissions and prioritizes system reliability projects to optimize impact on system performance for the dollars expended. The analysis focuses on the following:

Impact on SAIFI
Impact on CAIDI
Impact on network reliability index, also referred to as "network jeopardy"
Impact on customer satisfaction
Cost versus benefit incurred
Cost versus system benefit
Cost versus "pocket program" improvements

Distribution Engineering meets with the Regional General Managers and Regional Engineering Managers to discuss the above cost/benefit measures and Distribution Engineering's recommended priority list for the reliability projects, and arrive at consensus regarding the priority order of reliability projects to be submitted to the Senior Vice President.

The five-year System Reinforcement request is submitted to Planning & Analysis listing all programs and projects for the five year request, the current budget and current working estimate (CWE). A cut-off line is established based on available funding. Projects above the line are included for authorization in the annual ED-1 budget. When necessary, recommendations are made to shift crews among Regions to provide resources for critical work.

- **<u>Electric Transmission and Substation Project Prioritization</u>**

In order to optimize the allocation of funds in the budget process, the prioritization process was developed to evaluate the relative benefit of each proposed project. To facilitate the evaluations, a matrix of attributes provides insights into a project's effect on operational needs, risk, value, and interdependencies. The specific attributes to be used for the prioritization process incorporate Con Edison's mission and goals, and were developed by incorporating a prior Con Ed system and current industry practices. Seventeen attributes were selected, defined and weighted as to their value to company needs. Each of the attributes was further defined as to the relative impact on individual attributes so that project scoring would be more detailed and replicate the management decision-making process. This information was summarized into a matrix that was used as the evaluation tool.

Evaluations are made using project write-ups and reviewed with project sponsors. An initial determination of mandatory projects is made. Those that are government mandate/must do/failures are assigned priority A. Projects that are Load relief *!* capacity changes are assigned priority B. Interconnection work is assigned priority C. Projects that are not mandatory are scored using the numerical matrix and the weighted score for each attribute is totaled to provide a final project score. The projects are then ranked in accordance with these project scores and reviewed with the user organization. The final review is used to reconcile the approximation of the numerical system with the judgment of the managing authority of each business unit.

The elements of the prioritization system are attached, “Attribute Definition.pdf.”. They are the prioritization attribute list with the definition of each attribute and rules used to score that attribute, and the matrix used to perform the preliminary determination. This is summarized below:

Attribute	Weight
Safety/Health	15%
Demand Relief or Capacity Change	15%
Reliability MTBF or % Overduty	7.5%
Availability	7.5%
Regulatory or Environmental	7%
Obsolescence	7%
Cost	6%
Technical Improvement	5%
Operational Technical Improvement	5%
Efficiency	5%
Carryover of Work in Progress	5%
Structural Restoration	5%
Public Perception	4%
Outage Availability/Coordination	2.5%
Strategic Issue	2.5%
Report Recommendation	1%

Electric Operations and Substation Operations are presently working to develop one overall prioritization methodology. This methodology would be a tool that can be used to ensure that projects and programs are prioritized in a similar across both groups, and that capital infrastructure investment benefits would be optimized. Priorities will be aligned with maintaining Company strategic investments and managing the Company's identified enterprise risks.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS11
Date of Response: 06/17/2009
Responding Witness: IIP

Question No. :82
Subject: Substation Operations – System and Component Performance – Relay Protection System Redundancy (Single Point of Failure) - 1. Provide a copy of the current NERC Reliability Standard and explain the state of development of the NERC Project 2009-07 as it stands today. 2. When is the NERC Project 2009-07 Standard Drafting Team expected to post the draft standard? Provide a copy if any draft already exists. 3. Provide in detail the Company's current plan to implement this project over a 10 year period. Include the name and location of each switching station, and the changes that are required for each. 4. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the planning and work projected to be performed in 2010, 2011, and 2012.

Response:
Question 1 - No current NERC Reliability Standard exists covering relay redundancy or "single point of failure", and thus no copy of the Standard can be provided. The Standard Authorization Request (SAR) form for such a standard was submitted on January 7, 2009, and approved by the NERC Standards committee on January 14, 2009. The comment period for the SAR closed on February 18, 2009.

Question 2 - NERC has not published a completion date for the new Standard. As stated in response to Staff 82.1, only a SAR form exists, not a draft Standard; thus a copy cannot be provided. The only other significant and pertinent document is the Technical Paper referenced in the SAR form. A copy of the SAR form and Technical Paper is attached.

Question 3 - A detailed plan for implementation has yet to be developed. The Company's plan is as follows: After the new Reliability Standard is approved by NERC and endorsed by FERC, we will conduct an extensive survey of the facilities that are part of the applicable Bulk Electric System, in order to develop the scope of the modifications needed to comply with the standard. Using this scope as the basis for a new program, we will then initiate projects to implement the modifications. The schedules and cost estimates for each project will be developed as part of Con Edison's standard Capital Project Process.

Question 4 - The extent of the work needed, and the associated costs, to comply with the future standard cannot be fully estimated at this time because the specific provisions of the standard are not fully determined. Furthermore, the applicability of the standard may change in the near future if the definition of the Bulk Electric System within the Northeast Power Coordinating Council changes from its current definition.

Con Edison has estimated the overall cost of implementing these changes at $350 million over an 20 year period. This is an order of magnitude estimate to meet the NPCC A5 criteria for twenty-five 138kV switching stations. The A5 criteria requires redundancy, separate current transformers, separate batteries, physical separation, separate breaker trip coils, and separate and redundant tele-protection. A key unknown of the proposed standard is whether or not physical separation for cabling and 1st and 2nd line relay panels will be required. Since this requirement is not fully determined, we have budgeted $2 million in 2010. That $2 million will be used for design evaluation and commence equipment procurement.

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A Technical Paper

Protection System Reliability

Redundancy of Protection System Elements

NERC System Protection and Control Task Force

to ensure the reliability of the bulk power system

November 2008

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This Technical Reference Paper was approved by the NERC Planning Committee on December 4, 2008.

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1. Introduction

"Redundancy, in the context of this paper, further specifies that the fault clearing will meet the system performance requirements of the NERC Reliability Standards."

The 1997 NERC Planning Standards[1] contained tenets on Protection System redundancy that were not included in the Version 0 translation of those standards. Consequently, the NERC Planning Committee charged the System Protection and Controls Task Force (SPCTF) in late 2005 with preparing a Standard Authorization Request (SAR), with associated justifying technical background material, to reintroduce Protection System redundancy. This technical paper provides the background and support for the development of that Protection System Reliability SAR.

The reliability of the Bulk Electric System (BES) is normally measured by determining the performance of all the various power system elements and their ancillary systems. Protection Systems, being ancillary systems, are critical to establishing and maintaining an adequate level of BES reliability. The NERC reliability standards define the level of reliability to which each owner must design the BES and this in turn, can be used to determine the performance requirements of electric system elements such as breakers, and Protection Systems.

"…the Protection Systems must operate and clear faults within the required clearance time to satisfy the proposed performance requirements…"

This paper, developed by the NERC System Protection and Control Task Force (SPCTF), proposes Protection System reliability requirements and discusses the reasoning behind the requirements, provides examples and explanations concerning each requirement, and describes how to determine the level of Protection System reliability necessary to meet each requirement. This paper also describes a collaborative and interactive process between the protection and planning engineers to determine the required level of Protection System performance. It should be noted that in parallel to this effort is an IEEE PES/PSRC work group[2] that is developing a special report addressing redundancy considerations for relaying. SPCTF has a liaison relationship with that working group. The IEEE effort concentrates on the Protection System elements while this paper concentrates on the BES performance implications of Protection System redundancy.

[1] NERC Planning Standard, Section III – System Protection and Control, September 1997
[2] IEEE/PES/PSRC I19 Working Group

This paper evaluates Protection System clearing times for a normal electric system configuration (planned peak load conditions with all lines in service, typical generation dispatch, typical interchange, and typical switching configuration) for a fault on one electric system element with a Protection System component failure. For a component failure of the Protection System, redundant local backup, and remote backup Protection Systems are evaluated to determine the clearing time for the faulted electric system element under review. Due to the additional complexities involved, the performance requirements of backup Protection Systems for other electric system contingencies are not addressed in this paper.

1.1 The Need for a Protection System Reliability (Redundancy) Standard

Protection System reliability has been incorporated in NERC standards for decades and, in most situations, has been achieved through and referred to as redundancy. Redundancy is defined as "the existence of more than one means for performing a given function[3]." The NERC Planning Standards (see Appendix C) contains references to "delayed clearing" and Protection System failures, however, these terms were not clearly defined and often were interpreted to be synonymous with operation of breaker failure protection. Breaker Failure protection has a predictable result and designed tripping times. Protection System failures can lead to a more severe system response as a result of longer fault clearing and more electric system elements being removed from service to clear the fault. In later sections of the old planning standard[4], owners were required to incorporate redundancy in the Protection Systems as necessary to meet the reliability performance table (Table I. Transmission Systems Standards; C Normal and Contingency Conditions). References were made to various components of the Protection Systems that needed to have redundancy but no requirements were listed.

The old standards were vague and incomplete and did not directly correlate the need for redundancy to desired BES performance. It is necessary that a new approach be introduced to address the performance of the Protection System and provide the owner with clear tests and measures that can be used to determine when the application of redundancy is necessary. This technical paper has been developed to provide clarity on Protection System redundancy requirements, based on the relationship between performance of the Protection System and the performance of the BES. The approach introduced in this paper moves away from a prescriptive

[3] IEEE Standard C37.100-1992.
[4] NERC Planning Standard, Section III – System Protection and Control, September 1997

requirement based on a certain class or category of Protection Systems for specific voltage levels or generation amounts.

Local redundancy of components plays a major role in elevating the reliability of Protection Systems; however, it is not the only mitigation that can be used to improve the reliability of Protection Systems. Remote Protection Systems may provide adequate Protection System reliability in some situations, provided that remote protection can detect faults and provide clearing times that meet performance requirements. It is the task of the protection and the planning engineers to determine the proper solution for each element (lines, buses, transformers) and in most situations, there may not be any change required to the Protection Systems that are currently installed. New and existing Protection Systems need to be examined and upgraded when they lack the performance necessary to maintain an adequate level of BES reliability.

2. Protection System Reliability

2.1 Dependability and Security

There are two facets to Protection System reliability; dependability and security as defined by IEEE standard C37.100–1992 and are shown below:

- **Dependability —** "The facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly." For purposes of this paper, dependability is a measure of the degree of certainty that a protective system will operate correctly when required, and at the designed speed. Dependability is a concern when a fault occurs within the protected zone.
- **Security** — "That facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly." For purposes of this paper, security is a measure of the degree of certainty that a Protection System will not operate incorrectly or faster than designed. Security is a concern for external faults and normal (unfaulted) operating conditions.

Protection Systems must be fundamentally designed to be both dependable and secure because it is presumed that components of the Protection System can sometimes fail. Overall design must strike a balance between dependability and security.

To illustrate the concept of a dependability-based failure, refer to Figure 2–1. Dependability based Protection System failures can result in longer fault clearing times and isolation of additional elements of the electric system. The relay at Sub 2 on Line 1 has failed and cannot operate to clear the fault. Backup and time delayed relaying will be required to clear this fault and the loss of the generator is inevitable. Relaying at Sub 3 and Sub 4 will need to sense the fault and operate. This gets more difficult as the apparent impedance from the sensing relay to the fault gets larger and in some situations the remote relays will operate sequentially or may not operate at all.

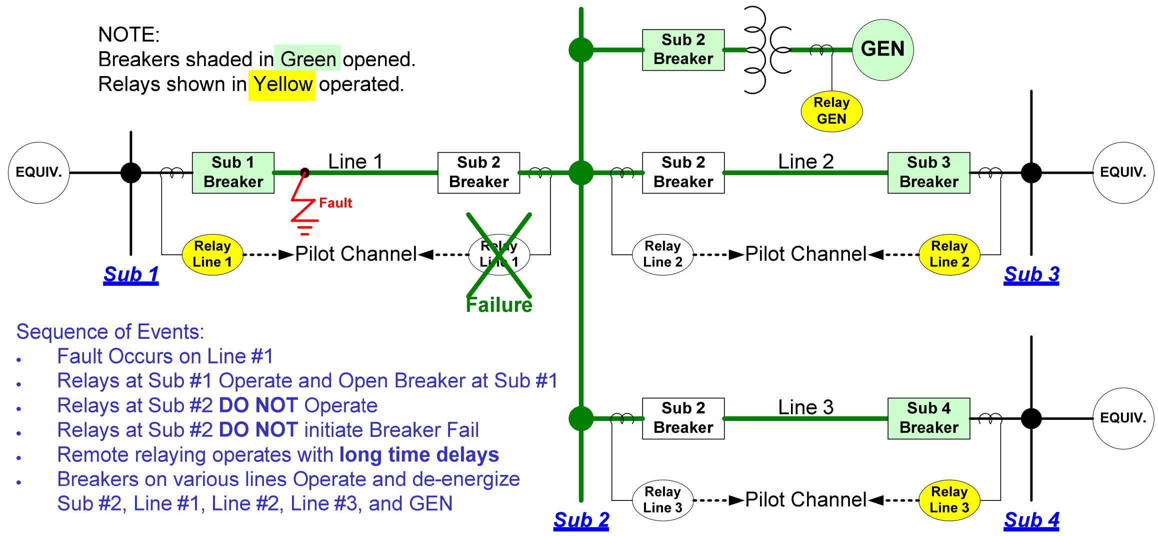

Figure 2-1 — Dependability-Type Failure (no trip) of a Protection System

In contrast, security-based Protection System failures can result in isolation of additional elements of the electric system as shown in Figure 2–2, but typically do not result in increased fault clearing time. In the last few years major system disturbances have been associated with both dependability and security based Protection System failures. However, this generally removes additional power system elements from service to clear the fault.

While redundancy reduces the probability of a dependability-based Protection System failure, it also increases the probability of a security based Protection System failure. Multiple Protection Systems provide a greater opportunity for an errant operation during a fault. For this reason, Protection System designs must provide a balance between dependability and security.

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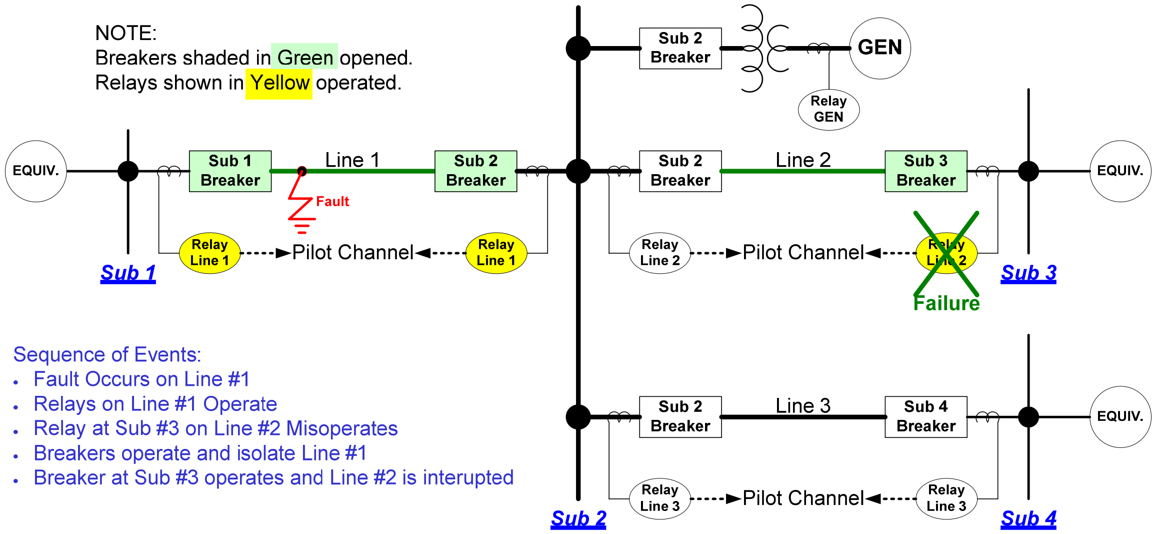

Figure 2–2 — Security-Type Failure (overtrip) of a Protection System

2.2 Need for Protection Reliability

The electric system network designs are planned and constructed to limit failure modes and equipment damage, and thereby enhance overall system reliability. The electric system is designed to balance performance and minimize the total transport cost of energy, which requires balancing of initial capital costs and long-term maintenance costs with the potential cost impact of a Protection System failure.

The design of Protection Systems must consider redundant components as a means to increase protection reliability, to minimize the impact of failures and allow the protection of an element to be returned to an acceptable level of performance and reliability. When a critical element of the electric system fails, the result can be catastrophic if additional equipment and Protection Systems are not available to minimize the impact. Electric system elements can be damaged, customer loads interrupted, instability on the grid can arise, and, in the worst case, blackouts can occur. Some equipment can require long lead times to repair or replace and electric system restoration can be time consuming if repair or replacement equipment is not readily available.

The power industry uses a practice of having redundant equipment available to quickly isolate problems, and spare equipment to return the electric system to normal operation. The application of breaker failure schemes with breaker-and-a-half, double-breaker lines, or main and transfer buses is an example of this. These designs utilize redundant or backup breakers to isolate the fault, and if one of the breakers is damaged and cannot quickly be retuned to service, it can be isolated and the alternate breaker or bus can be used to restore the electric system to stable operation.

It is not economically feasible to design an electric system to withstand all possible equipment failures and abnormal operating conditions. Therefore, all electric systems must deploy highly reliable Protection Systems that can quickly detect abnormal conditions and take appropriate actions to ensure removal of electric system faults. Protection System reliability is normally achieved by designing Protection Systems with adequate redundancy of equipment and functional adaptability to minimize single component failures, such as automatically decreasing the zone 2 timer for loss of a Protection System communication channel.

2.3 Protection System Redundancy

A fundamental concept of redundancy is that Protection Systems need to be designed such that electric system faults will be cleared, even if a component of the Protection System fails. Redundancy is a system design that duplicates components and/or systems to provide alternatives in case one component and/or system fails. ***"Redundancy," in the context of this paper, further specifies that the fault clearing will meet the system performance requirements of the NERC Reliability Standards.***

Relay Terminology

Most Elements on the bulk power system are protected by multiple Protection Systems and the names applied to the multiple protection systems include: Primary, Secondary, Backup, Local Backup, Remote Backup, System A and B, System 1 and 2.

This paper refers to paired relaying systems as primary and secondary, #1 and #2, and A and B. Each of these systems must meet the performance requirements, such as minimum clearing times, but may have different operating principals and equipment. For example, if high speed operation and sensing on 100 percent of the line is needed, both paired relaying systems are required to provide this type of performance.

Backup relaying provides a different role than paired relayed systems and usually has less speed and maybe less selectivity. In this paper, the term backup relaying refers to protection that is installed to operate when paired relaying systems are not available and can be located locally or remotely.

Redundancy means that two or more functionally equivalent Protection Systems are used to protect each electric system element. Redundancy can be achieved in a variety of ways depending on the performance required and the infrastructure available. In some cases redundancy means that there are two locally independent Protection Systems that have no common single points of failure. This solution is usually applied when performance requires high-speed isolation of faults, or if the electric system cannot withstand longer fault clearing times and/or over-tripping for Protection System failures. When time delayed clearing of faults is sufficient to meet reliability performance requirements, owners may deploy one primary and one remote or local backup system to meet reliability levels. Owners often refer to these systems as primary and secondary or backup systems. In both cases, ***the Protection Systems must operate and clear faults within the required clearance time to satisfy the proposed performance requirements*** (see section 4.0).

Figure 2–3 shows a simple non-redundant Protection System and Figure 2–4 shows a fully redundant Protection System. It should be noted that the single Protection System shown in Figure 2–3 could be sufficient to maintain reliability if there are sufficient remote backup Protection Systems that can operate to isolate the fault and maintain reliability.

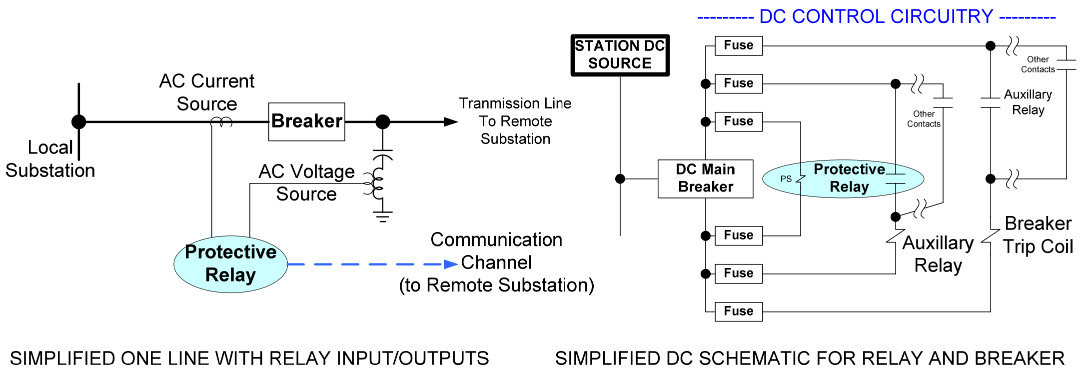

Figure 2–3 — Non-Redundant Protection System

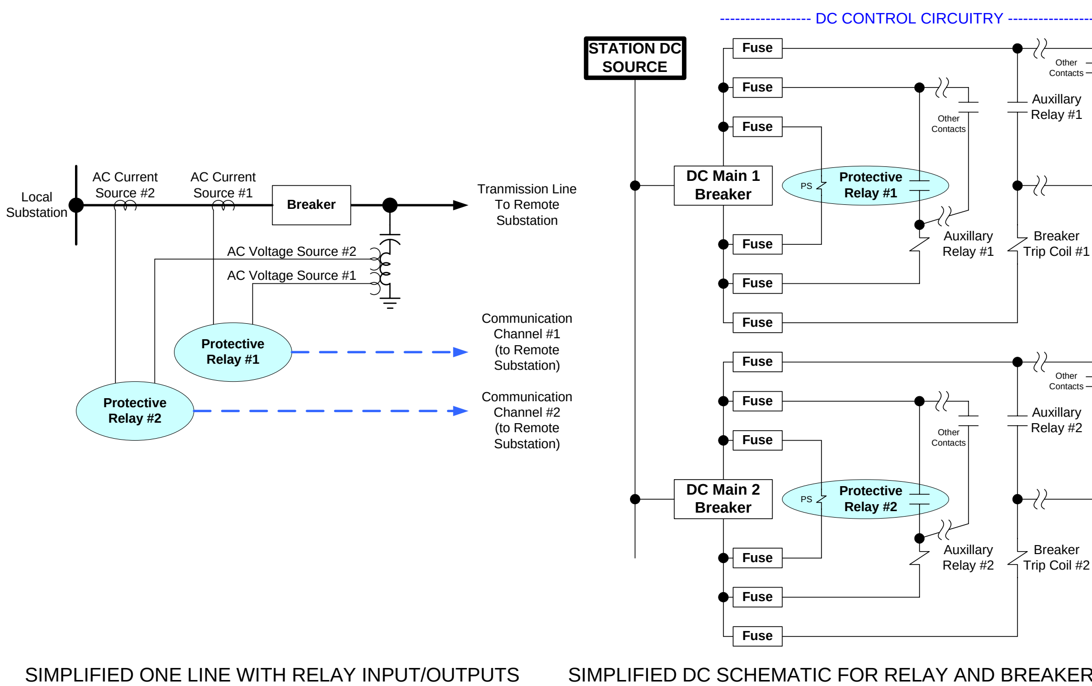

Figure 2–4 — Fully Redundant Protection System

The following are some examples of redundant protection applications.

- Multiple Protection Systems of similar functionality (tripping speeds) may be used to satisfy the performance requirements. For example, when high-speed clearing is required, the use of a current differential scheme with a Permissive Overreach Transfer Trip (POTT) or Directional Comparison Blocking (DCB) scheme as a second scheme can provide the necessary redundancy.
- Multiple Protection Systems with varying functionality may be used if one system has functionality in excess of what is needed to satisfy the performance requirements. For example, the Protection Systems may consist of one pilot Protection System (for high speed clearing of the entire circuit), with a second system using stepped-distance non-pilot protection, if the stepped-distance system itself meets the requirements to satisfy the performance requirements.
- Separate Protection Systems of varying functionality can be used where one system is enabled upon failure of the other system. For example, high-speed overcurrent relays that are enabled upon loss of a pilot communication system may be used if the overcurrent relays satisfy the performance requirements. However, this application method may introduce a possibility of over tripping due to the failure of the pilot scheme. Both failure modes must be checked to assure that they meet performance requirements.
- Local or remote backup protection may be used to satisfy redundancy, where the backup protection itself satisfies the reliability performance requirements.

3. Reliability of the Bulk Electric System

The reliability performance design requirements of the electric system are defined by the NERC TPL standards for the planning horizon. That performance is based on various criteria that determine acceptable conditions for BES performance under system normal conditions and after various system contingencies.

NERC has also published a document that explains the concept of Adequate Level of Reliability (ALR)[5] across all planning and operating horizons, allowing various standards to reference and use common concepts to determine reliability performance requirements. The adequate level of reliability centers on the following criteria:

- The System remains within acceptable limits;

[5] "Characteristics of a System with an Adequate Level of Reliability," approved by the NERC Board of Trustees in February 2008, and filed with the FERC.

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- The System performs acceptably after credible contingencies[6];
- The System limits instability and cascading outages;
- The System's facilities are protected from severe damage; and
- The System's integrity can be restored if it is lost.

To ensure that Protection Systems installed on the electric system meet those tenets, the approach introduced in this paper requires Protection Systems to be designed such that no single Protection System component failure would prevent the BES from meeting system performance requirements in the NERC Reliability Standards.

- This Technical Paper is devoted to the methods for evaluating the application of Protection System redundancy and its resultant impact on BES performance for faults occurring starting from electric system normal conditions (planned peak load conditions with all lines in service, typical generation dispatch, typical interchange, and typical switching configuration). The need for redundancy is determined by examining Protection System performance in light of Protection System element failures and whether or not the resultant BES performance is acceptable to meet the proposed performance requirements (see Section 4.0 of this document).

This paper does not cover all aspects of Protection System reliability. For example, it does not prescribe methods for setting the Protection System or the application of remote backup protection, and does not address the potentially special protection needs of circuits that are part of the "cranking path" for power system restoration.

3.1 2002 NERC Planning Standards

The current NERC Planning Standards (TPL-001 through TPL-004) were developed as part of the "Version 0" standards in 2002. Those standards are soon to be consolidated into a single standard that refines the categories of contingencies, applicable conditions, and performance requirements. Changes under consideration include more prescriptive information regarding how Protection Systems are to be considered. The Version 0 planning standards did not consider Protection System failures for normal operation of the electric system, and separated outages and conditions into four categories which are paraphrased below.

Category A — No Contingencies (all facilities in service)

- Facility rating must be maintained (thermal and voltage)
- The system must remain stable

[6] Beyond the scope of this document.

- No Loss of demand or firm transfers allowed
- No Cascading allowed

Category B — Event resulting in the loss of a single element

A category B event can be a single-line-to-ground or three-phase fault with the Protection System operating normally, with normal or designed clearing times. The transmission system is required to remain stable with all equipment loaded to within its applicable operating limits, and with no load shedding or cascading outages.

- Facility rating must be maintained (thermal and voltage)
- The system must remain stable
- No Loss of demand or firm transfers allowed
- No Cascading allowed

Category C — Events resulting in the loss of two or more elements.

A category C event can be a single-line-to-ground fault on a bus section or a breaker failure with the Protection System operating normally, with normal or designed clearing times. It also can be independent events when single-line-to-ground or three-phase faults occur on multiple elements with time for manual system adjustments between events, or a single-line-to-ground fault with a Protection System failure. In this case, some controlled load shedding is acceptable. Acceptable system performance requires that:

- Facility rating must be maintained (thermal and voltage)
- The system must remain stable
- Only Planned or Controlled Loss of demand or firm transfers allowed
- No Cascading allowed

Category D — Extreme event resulting in two or more elements removed or cascading out of service

A category D event can be a catastrophic failure of a piece of equipment or a three-phase fault preceding a breaker failure with a Protection System failure.

- Loss of Customer Demand and Generation may occur
- The system is not required to return to a stable operating point

3.2 Clearing Times

The planning engineer typically considers three levels of Protection System performance: Normal Clearing Time, Breaker Failure Clearing Time, and Delayed Clearing Time. In the planning standards, the performance requirements vary based on the combined probability of an electric system event

Breaker Failure and Delayed Clearing

According to the NERC Glossary of Terms, Delayed Fault Clearing is defined as "Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay."

For purposes of this paper, delayed clearing times are differentiated into the two components of that definition. This section describes the differences.

For example, zone 2 clearing for a line end fault would be considered normal clearing when the line is protected by stepped-distance protection, but would be considered delayed clearing when the line is protected by high-speed pilot protection with stepped-distance protection as backup if the high speed scheme did not operate.

occurring, and the level of Protection System performance under consideration.

Categories A and B in the 2005 Version 0 Standards consider that the Protection System operates normally. Category C considers breaker failure and some delayed clearing times due to Protection System failure. Category D takes in account multiple contingencies including breaker failure and Protection System failure. The planning engineer must consult with the protection engineer to correctly model the Protection System performance in those system studies.

3.2.1 Normal Clearing Time

Normal clearing time is a Protection System mode of operation that does not take into consideration Protection System failure, and assumes that the Protection System is fully functional and will operate as designed and intended. Normal clearing time for the Protection System is based on the time in which each Protection System component is expected and designed to operate. For example, a communication aided Protection System is design to provide instantaneous operation (without intentional time delay) for all faults on the line. The normal clearing time for this example might be 4 cycles (2 cycles for relay time and 2 cycles for breaker time). Fault location must also be considered in determining worst case clearing times. For example if a line is protected by step distance protection (non-pilot), faults at the end of the line would be cleared by time delayed relaying and the normal clearing time for this fault might be 22 cycles (2 cycles for relay time, 18 cycles for intentional time delay, and 2 cycles for the breaker).

3.2.2 Breaker Failure or Stuck Breaker Clearing Time

Breaker Failure clearing time is a mode of operation that considers the Protection System to be fully functional and will operate as designed and intended. However, it also considers that a breaker needed to isolate the fault failed to operate (remained closed or stuck). Planning engineers determine the critical clearing time for stuck breaker and/or breaker failure conditions. The protection engineer will account for this time when designing the breaker failure relaying protection. For example, the planning engineer might determine that the critical breaker failure clearing time is 12 cycles and this might result in the protection engineer setting the breaker failure timer at 8 cycles (2 cycles for relay time, 8 cycles for the breaker failure timer, and 2 cycles for breaker tripping). In some cases the protection engineer may determine that the critical clearing time cannot be achieved without compromising security of the Protection System. In such cases, the planning engineer must design the electric system around this constraint (e.g., installing two breakers in series to eliminate the breaker failure contingency or constructing additional transmission elements to improve system performance, thereby increasing the critical clearing time).

3.2.3 Delayed Clearing Time

Delayed clearing time is a mode of operation that is a result of a Protection System failure to trip the breaker directly and/or initiate breaker failure logic. If a Protection System fails to clear the fault or initiate breaker failure, other relaying, locally or remote, will need to operate.

The protection engineer will need to closely examine all protection schemes locally and remotely to determine how Protection System failures will be mitigated. The worst case situation is that the Protection System failure did not trip or initiate breaker failure protection. However, certain failure modes could delay the initiation of breaker failure but not the transfer trip from the remote terminal. Only certain component failures are proposed for consideration and only these failures need to be studied and each component failure might provide different delayed clearing times. A Protection System failure might result in local or remote relays operating and, based on the particular substation, this could significantly extend clearing time.

3.2.4 Planning Standard Development

The revised planning standard presently under development[7] provides for event categories (P1 through P7) based on single or multiple contingencies, and has differing performance requirements for steady-state and dynamic (stability) conditions. P5 is the category that considers Protection System failure during a fault. The proposed revision of the TPL standard uses two tables for the steady-state and stability performance requirements (paraphrased below from the draft TPL standard).

Table 1 - Steady-State Performance

1. Facility Ratings shall not be exceeded. Planned system adjustments are allowed to keep Facilities within the Facility Ratings, unless precluded in the Requirements, if such adjustments are executable within the time duration applicable to the Facility Ratings.
2. System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).

[7] See the Standards portion of the NERC website at: http://www.nerc.com/page.php?cid=2|247|290

3. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
4. Consequential Load and consequential generation loss is allowed, unless precluded in the Requirements.
5. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
6. Simulate Normal Clearing times unless otherwise specified.

Table 2 - Stability Performance

1. The System shall remain stable.
2. Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive)
3. Uncontrolled islanding and cascading outages shall not occur.
4. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
5. Simulate Normal Clearing times unless otherwise specified.

4. Proposed Protection System Reliability (Redundancy) Requirements

Protection System reliability must support the overall reliability requirements of the Bulk Electric System. The approach introduced in this paper establishes a Protection System Reliability (Redundancy) requirement in keeping with the tenets of Adequate Level of Reliability (ALR). Since the planning standards define the reliability performance to which the BES should be designed, those requirements can, in turn, be used to establish performance requirements for the reliability of Protection Systems. The approach introduced in this paper addresses the planning standard performance requirements that pertain to or rely on Protection System performance.

Proposed Requirement

For system normal pre-fault system conditions, the Protection Systems must clear all single-line-to-ground and multi-phase faults in a clearing time such that:

1. System steady state voltages and post-transient voltage deviations shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).
2. Facility Ratings shall not be exceeded.
3. The system must remain stable.
4. The protection system must not trip system elements beyond those associated with the designed backup protection (local or remote), not including possible UFLS or UVLS operation.

NOTE: The proposed requirement is intended to mimic the performance requirements of the TPL standards. The TPL Standards should be the defining document for codifying the performance testing.

The approach introduced in this paper may appear to raise the design requirements of all Protection Systems; however, it only applies to those Protection Systems for which a failure causes the BES performance to violate one of the four requirements above. In many situations, the Protection Systems already employs sufficient redundancy and will not need to be upgraded or changed. In some other situations, where the Protection System is not redundant, backup or remote relaying may be sufficient with no upgrades or changes needed because Protection System failures do not result in violation of the BES performance requirements specified in the TPL standards.

The approach introduced in this paper *may* raise Protection System design requirements for some by calling for the examination of system performance in conjunction with specific levels of Protection System performance. It then requires mitigation for those conditions where Protection System component failures result in violation of the BES performance requirements.

4.1 Evaluating BES Performance

BES performance must meet the performance requirements specified in the TPL standards when a single component failure occurs within the Protection System. When a single component failure mode will prevent meeting the BES performance defined in the TPL standards, either the Protection System or the electric system design must be modified.

Providing Protection System redundancy is one method for ensuring that the BES meets the performance requirements of the TPL standards. Some examples are provided below to guide the application of the Protection System Reliability Standard.

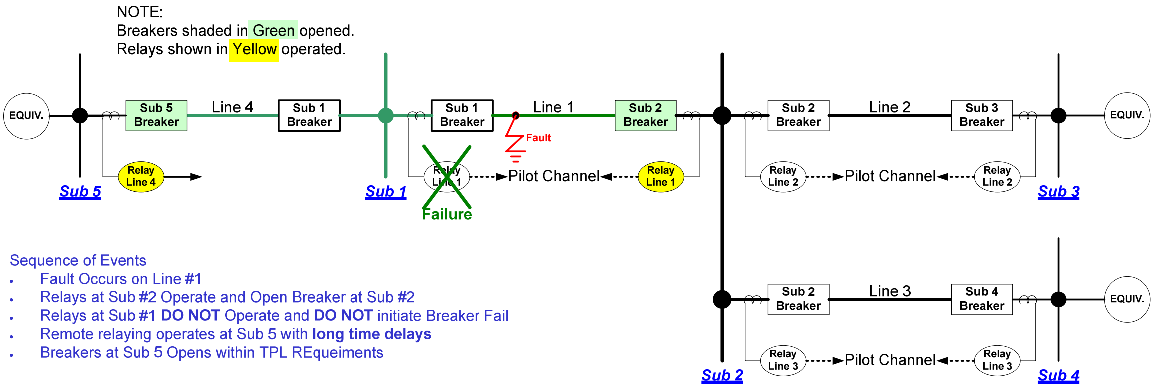

Figure 4–1 — Acceptable Delayed Clearing Example

1. Refer to Figure 4–1 — A power grid element (Line 1) requires a critical clearing time (for stability) of 50 cycles, and the element is protected by a single local pilot aided Protection System. Remote backup is available at Sub 3, Sub 4, and Sub 5 which will clear all faults on the element within 40 cycles. Therefore, a failure of the local protection on the element will not violate BES performance requirements (for voltage, facility ratings, or stability), and local redundant protection is not necessary; the remote backup protection provides the necessary reliability. Figure 4–1 illustrates what would happen for a non-redundant Protection System failure at Sub #1 for a fault on Line #1.

2. Refer to Figure 4–2 — A power grid element (Line 1) requires a critical clearing time of 20 cycles and the remote backup is capable of clearing faults for this element in 30 to 60 cycles. The local Protection System has various single points of failure that will require the remote backup schemes to clear the power grid element resulting in an unstable system. This is an infraction of the "System Must Remain Stable" performance requirements in the TPL standards. However, the failure must be tested for post transient voltage violations and facility rating violations also. The approach introduced in this paper would require the Protection System to be modified so that single component failures do not result in a violation of the BES performance requirements in the TPL standards. The Protection Engineer would then need to review the other proposed requirements (see Section 5) to make appropriate changes to the Protection System.

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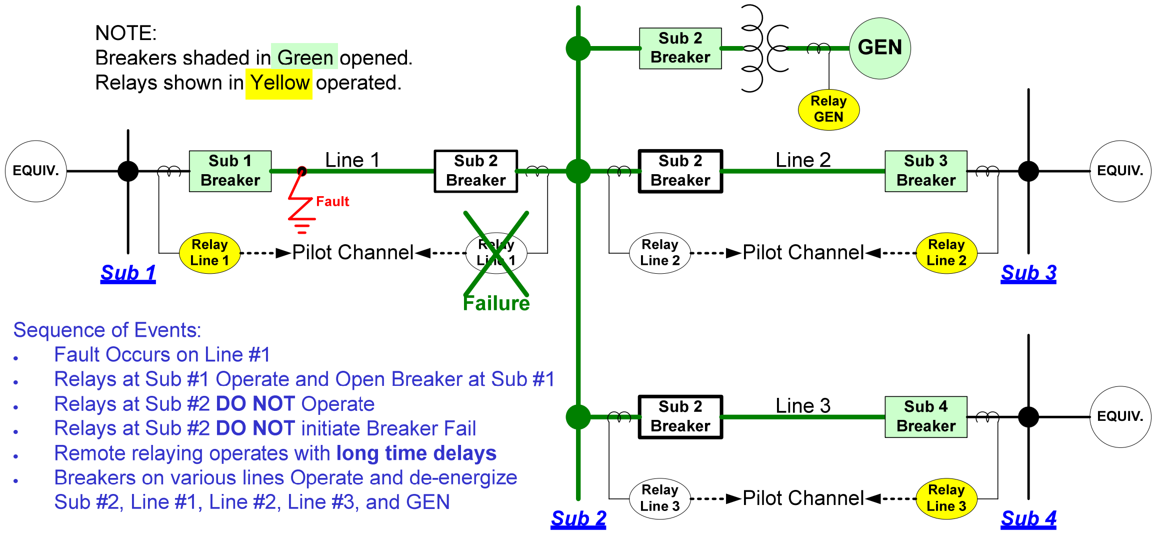

Figure 4–2 — Unacceptable Delayed Clearing Example

3. A transmission line at a generating plant requires the isolation of faults in a critical clearing time of 9 cycles (3 cycles plus breaker failure clearing time of 6 cycles). This example requires high-speed clearing (communication-aided relaying systems) to meet the 3-cycle clearing time and a breaker failure scheme capable of 6 cycle delay in order to meet the BES performance requirements of the TPL standards. In this case, no time-delayed backup system (either local or remote) can satisfy the 3-cycle requirement and violations could occur to facility ratings, stability, and post transient voltage violations at remote busses. The approach introduced in this paper would require redundant pilot relaying systems, (see Section 5), to assure that faults are detected and cleared within 9 cycles, even with a failed breaker or primary Protection System failure.

4. A line at a generating plant has a critical clearing time of 4 cycles, where breaker failure following an operation of a high-speed relaying system would result in system instability which is a violation of the BES performance requirements of the TPL standards. In this case, it may be necessary to add a redundant (series) breaker to meet the BES performance requirements in addition to other redundant protection as described in the third example above.

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4.2 Development of a Testing Methodology to Determine the Need for Redundancy

The protection and planning engineers must work collaboratively to determine the need for Protection System redundancy. Portions of that process may be performed in parallel and may be iterative in nature.

Roles of the Protection and Planning Engineer

- The protection engineer's role is to determine the performance of the Protection System through analysis of its failure modes and determine the operating times of the relaying.
- The planning engineer's role is to determine if the clearing times provided by the protection engineer satisfy the system performance requirements through transmission planning studies.

From the general discussion in Section 4.1, the following testing methodology has been developed for assessing compliance with the BES performance requirements of the TPL standards The order of these tests can be varied.

Methodology

- **Determine Redundancy of the Protection Systems —** Examine the Protection System for redundancy of the following components - AC Current Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, and Station DC Source. If the owner has determined that the listed components are redundant, no further action is needed except documentation.
- **Ascertain the Performance of the Protection Systems —** Based on the determined redundancy of the Protection System, determine the Protection System performance for a failure of each component listed above, or determine the worst case clearing time for Protection System failure.
- **Compare BES Performance with Required Performance —** Determine if the clearing times determined meet the BES

Worst Case Fault Test

The term 'worst-case fault' implies one of the four classical fault types – line to ground, line to line to ground, line to line, and three phase – with the location of the fault being placed where it results in the worst electric system performance. This fault may not be coincident with the location where a fault is hardest to detect or creates the longest clearing time for the local or remote backup protection system(s). The worst case fault typically must be identified through a collaborative effort between the planning and protection engineers.

To minimize the effort, conservative assumptions regarding fault clearing time may be made initially. When system performance evaluated in the planning study meets the TPL standards' performance requirements no refinements to the initial assumptions are required. When system performance does not meet the TPL standards' performance requirements, the initial assumptions must be refined and the system performance re-evaluated. This iterative process continues until system performance meets the TPL standards' performance requirements with conservative assumptions or the worst fault location has been identified and evaluated using actual clearing times.

performance requirements listed in the TPL standards.

- **Mitigate all Violations —** Modify the electric system or Protection System design to eliminate any conditions identified for which the BES performance violates the requirements in the TPL standards.

These steps should be repeated whenever Protection Systems or electric systems are modified in some manner which changes the BES performance; such cases must be reviewed to assure that the BES still meets the performance requirements specified in the TPL standards**.**

4.2.1 Determine Redundancy of the Protection System

The protection engineer will need to examine the following components - AC Current Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, and Station DC Source. Each component should be examined to determine how the failure would impact operation of the Protection System.

Consider the two examples below. The first is an example of a non-redundant Protection System with possible solutions for component failures. The second is an example for a fully redundant Protection System.

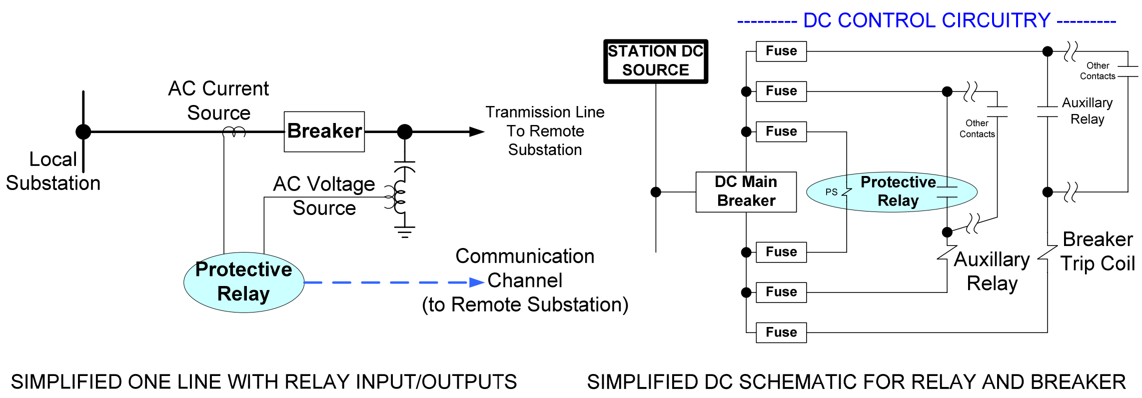

Figure 4–3 — Example 1 – Study of Protection System Reliability for Non-Redundant Systems

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The following table is a non-exclusive list of possible impacts of dependability –based Protection System component failures or removal of components from service during a fault.

Table 4–3 — Example 1 – Study of Protection System Reliability for Non-Redundant Systems

Component	Possible Impacts	Solutions
AC Current Source	Loss of AC current input to the protective relay usually disables the ability of the Protection System to sense faults which would result in delayed clearing times.	1. Add redundant AC current input and an additional relay or 2. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards. standard)
AC Voltage Source	Loss of AC voltage input to the protective relay can disable the ability of the Protection System from sensing some faults. A high speed current-only relay will not be impacted by this failure and clearing times will depend on application. Worst case scenarios require delayed clearing times to be considered.	1. Add redundant AC voltage input and an additional relay or 2. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards.
Protective Relay	Loss of protective relay means that faults can not be cleared locally which would result in delayed clearing times.	1. Add redundant relay or 2. Verify that time-delayed clearing does not violate the BES performance requirements of the TPL standards.
Communication channel	Loss of the communication channel of the Protection System usually requires delayed clearing times for some faults on the transmission line (i.e. near the remote terminal). Worst case scenarios may require delayed clearing times be considered.	1. Add redundant communication channel and possibly additional relay and communication equipment or 2. Verify that time delayed clearing does not violate the BES performance requirements of the TPL standards.
DC Circuitry	Loss of DC circuitry will depend on what components are disabled. If multiple components are impacted by the loss of a single circuit the entire Protection could be disabled. It could be possible that impact to the Protection System could be minimal. However, worst case scenarios may require remote delayed clearing times be considered.	1. Add additional DC circuits and separate critical components or schemes or 2. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards.

Table 4–3 — Example 1 – Study of Protection System Reliability for Non-Redundant Systems		
Component	**Possible Impacts**	**Solutions**
Auxiliary Tripping Relay	Loss of auxiliary tripping relays may impact the Protection System from providing a high speed trip, and may not prevent the protection System from initiating breaker failure protection. The result might be a clearing time that is longer than normal clearing times but less than delayed clearing times. Worst case scenarios may require delayed clearing times be considered if breaker failure is initiated by the auxiliary relay.	1. Add additional auxiliary relays or 2. Alter the scheme to provide parallel tripping paths or 3. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards.
Breaker Trip Coil	Loss of the breaker trip coil will cause the breaker failure scheme to operate. If breaker failure logic does not include removal of all sources remote relaying may be needed to isolate the fault. Worst case scenarios may require delayed clearing times be considered.	1. Add additional trip coil on a separate DC circuit or 2. Provide breaker fail and remote clearing for faults or 3. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards.
Station DC Source	Loss of the DC source prevents any relaying from operating at the station. Therefore, remote backup clearing times must be determined and compared against the critical clearing time for a fault at that station.	1. Add continuous and reported monitoring 2. Add another DC source 3. Verify that time delayed remote clearing does not violate the BES performance requirements of the TPL standards.

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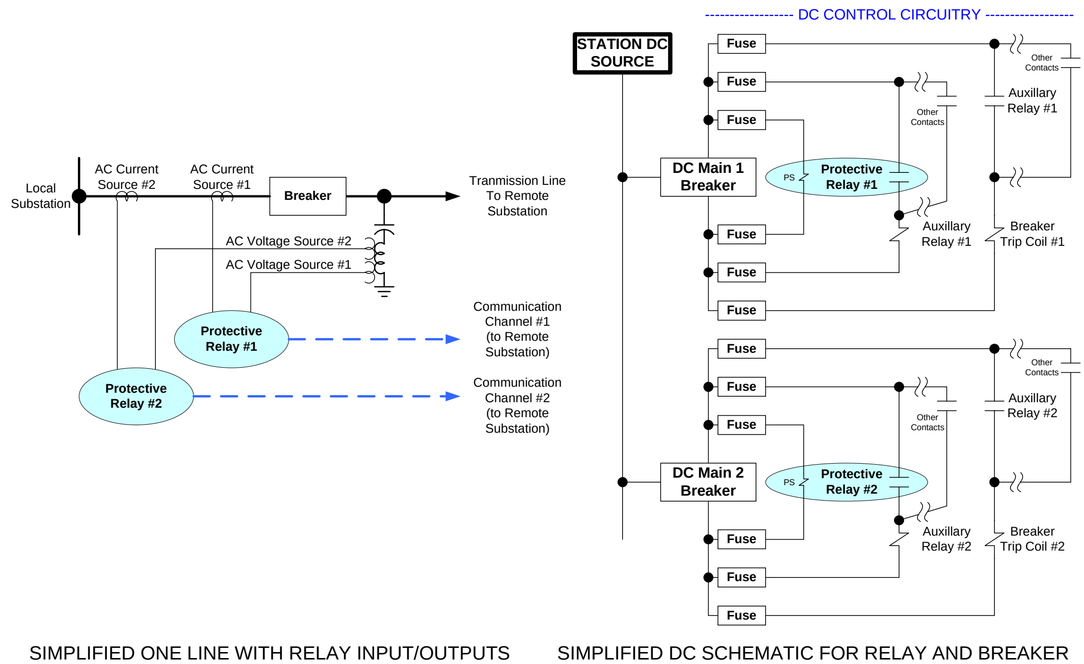

Figure 4–4 — Example 2 – Study of Protection System Reliability Redundancy for Redundant Systems

The following table is a non-exclusive list of possible impacts of dependability-based Protection System component failures or removal of components from service during a fault.

Table 4–4 — Example 2 – Study of Protection System Reliability Redundancy for Redundant Systems

Component	Possible Impacts	Solution
AC Current Source	Fault clearing is not impacted by the loss of single AC current input. Redundant AC current sources provide functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
AC Voltage Source	Fault clearing is not impacted by the loss of single AC voltage input. Redundant AC voltage sources provide functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
Protective Relay	Fault clearing is not impacted by single relay failure. Redundant relay provides functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
Communication channel	Fault clearing is not impacted by single communication channel failure. Redundant communication channels provide functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
DC Circuitry	Fault clearing is not impacted by loss of a single DC circuit. Redundant DC circuits provide functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
Auxiliary Tripping Relay	Fault clearing is not impacted by single auxiliary relay failure. Redundant auxiliary relay provides functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
Breaker Trip Coil	Fault clearing is not impacted by loss of single trip coil. Redundant trip coil relay provides functionally equivalent protection.	No immediate action needed. Repair or replacement must be made as soon as possible.
Station DC Source	Failure of one of the redundant DC sources does not impact fault clearing times.	1. No immediate action needed. Repair or replacement must be made as soon as possible.
	Failure of the single, fully monitored DC source will impact fault clearing times.	2. Take appropriate operator action and emergency repairs must be made.

4.2.2 Determining Performance of the Protection System

The protection engineer can determine the performance of the Protection System by analyzing failure modes of the Protection System components and the resulting Protection System operating time. The clearing times should be categorized for the three performance categories: Normal Clearing Times, Breaker Failure Clearing Times, and Delayed Clearing Times. The definition of these times are shown and discussed in Section 3 above. The protection engineer will document the operating times of the Protection Systems for all elements and then provide the planning engineer with these operating times to permit the planning engineer to determine BES performance based on case studies. Consider the example below.

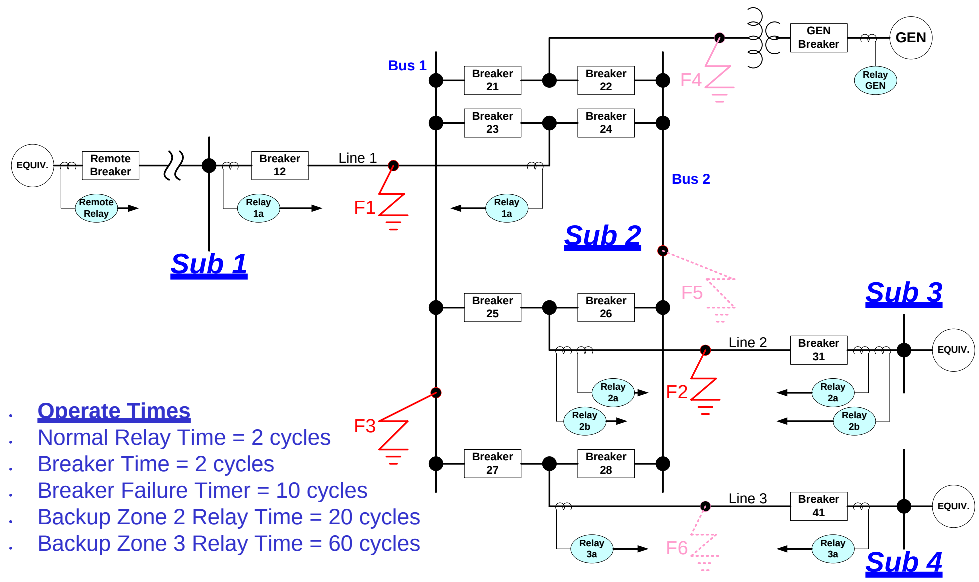

Figure 4–5 — Example 3 – Determining Protection Systems Performance

The following table is a non-exclusive list of possible clearing times of Protection Systems listed in the examples above.

Table 4–5 — Example 3 – Determining Protection Systems Performance (times are typical and will vary for each application)				
Fault Loc.	Normal Clearing Time	Breaker Failure Clearing Time	Does the Protection System have single points of failure?	Worst Case Clearing Time for Protection System Failure
	Sub 1			
F1	BKR 12 RLY 1a = 4 cycles	BRK 12 = 14 cycles	YES	**Remote Bus** Remote Relay = 22 cycles

Table 4–5 — Example 3 – Determining Protection Systems Performance (times are typical and will vary for each application)				
Fault Loc.	**Normal Clearing Time**	**Breaker Failure Clearing Time**	**Does the Protection System have single points of failure?**	**Worst Case Clearing Time for Protection System Failure**
F1 (cont.)	**Sub 2**			
	BKR 23&24 RLY 1a = 4 cycles	BKR 23 = 14 cycles BKR 24 = 14 cycles	YES	**Sub 2** GEN RLY = 62 cycles **Sub 3** RLY 2a = 62 cycles RLY 2b = 62 cycles **Sub 4** RLY 3a = 62 cycles
F2	**Sub 2**			
	BKR 25&26 RLY 2a = 4 cycles RLY 2b = 4 cycles	BKR 25 = 14 cycles BRK 26 = 14 cycles	NO	**Sub 2** BKR 25&26 RLY 2a or 2b = 4 cycles
	Sub 3			
	BKR 31 RLY 2a = 4 cycles RLY 2b = 4 cycles	BRK 31 = 14 cycles	NO	**Sub 3** BKR 31 RLY 2a or 2b = 4 cycles
F3	**Sub 2**			
	BKR 21, 23, 25, & 27 = 4 cycles	BKR 21 = 14 cycles BKR 23 = 14 cycles BKR 25 = 14 cycles BKR 27 = 14 cycles	YES	**Sub 1** RLY 1a = 62 cycles **Sub 2** GEN RLY = 62 cycles **Sub 3** RLY 2a or 2b = 62 cycles **Sub 4** RLY 4a = 62 cycles

4.2.3 Compare BES Performance with Requirements of the TPL Standards

The BES performance must meet the performance expectations of the TPL standards for the specified level of Protection System performance. In some situations the planner has already determined the critical clearing time for a fault. Fault clearing times in the range of 5 to 20 cycles will probably require full redundancy of the local Protection Systems. Fault clearing times that are longer than 20 cycles could provide the owner with the option of using remote backup protection to clear the fault. This over-tripping must also be examined to determine if there is any violation of the TPL standards' performance requirements. Prior to the 2005 Version 0 standards, planners tested the system for Normal and Breaker Failure clearing times and did not test for delayed clearing times because that was considered an extreme event.

Table 4.6 is a comparison of the relay performance clearing times and the acceptable system clearing times from the examples above. It should be noted that the critical clearing time is not met for the case with Protection System failure; an alternate designed would be required.

Table 4.6 — Acceptable Clearing Times
(times are typical and will vary for each application)

Line 1 – Fault F1	Actual Clearing Time	Critical Clearing Time	Violation of TPL-Standards
Normal Clearing Time	4 cycles	5 Cycles	None
Breaker Failure Clearing Time	14 cycles	15 Cycles	None,
Time Delayed Clearing Time- Protection System Failure	62 cycles	22 cycles	Stability

4.2.4 Mitigate All Violations of the TPL Standards

The planning engineer with support from the protection engineer can determine if the performance of the BES meets the performance requirements of the TPL standards for the specified level of Protection System performance. The performance of the Protection System is directly related to the failure of the various components. If a Protection System is fully redundant, no single protection component failure can impact the performance of the Protection Systems. However, if all components are not redundant, then some component failures can result in slower Protection System operation, potentially causing the performance of the BES to violate the TPL standards' performance requirements.

If a component failure prevents the Protection System from providing the required critical clearing time, then two options are available.

- Providing local redundancy can mitigate the Protection System component failures. This effectively makes the Protection System meet its designed operating time even when experiencing a single component failure. This could mean adding another AC Current

Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, or Station DC Source. Later sections will go into these descriptions in more detail.

- The protection engineer can assess the potential for improving the delayed clearing time from the remote backup protection and provide these revised values to the planner. The planning engineer can restudy this condition and determine if the BES performance meets the performance requirements of the TPL standards.

Planning engineers do not typically perform studies to identify delayed clearing times because studies can be very extensive for the many different elements, clearing times, and fault locations. However, the planning engineers do have the capability to study limiting conditions identified by the protection engineer. With the method specified in this section, the planning engineer will not have to run an infinite number of cases and can concentrate on the specific cases identified by the protection engineer.

An iterative process can occur as the protection engineer determines possible delayed clearing times and the electrical system components removed from service, and the planning engineer assesses the resulting BES performance for comparison with performance requirements of the TPL standards.

It will be necessary for the planning engineer and protection engineer to work collaboratively to identify those clearing times that need to be restudied or where the Protection System needs to be upgraded or modified to provide redundancy.

5. Protection System Components

Protection Systems are used to provide protection of all electric system elements. It is the primary job of a Protection engineer to apply these Protection Systems in a reliable manner to isolate all faults on the electric system. Protection Systems can be as simple as one relay that is applied to trip a breaker or very complicated and involve many functions and conditions and require equipment to be installed at multiple sites that use communication channels to transmit data. There are some basic components that make up most Protection Systems and these components must be applied in a reliable manner. The NERC Glossary of Terms lists the components of a Protection Systems as: Protective Relay, Associated Communication System, voltage and current sensing devices, station DC supply, and DC control circuitry. The old planning standard also made reference to these components.

> <u>Protection Components Addressed</u>
> The legacy NERC Planning Standard III.A (1997) included a Measure specifying the need for separate AC current inputs and separately fused DC control systems if the loss of one of these elements would result in an event that did not meet system performance requirements. The need for separate AC current inputs implies the need for separate relays and the need for separately fused DC control systems implies the need for separate trip paths including auxiliary lockout or tripping relays, if used. The old Standard IIIA also included guides regarding the use of dual trip coils and communication systems. Recent and past Transmission System events with consequences that do not meet modern system performance requirements have occurred due to the failure of a single protection system component.
>
> The list of components specified for performance tests in Section 5.0 of this technical paper were derived from the historical standards, experience from system events, and the collective judgment of protection engineers representing all the North American Reliability Regions. The list of components is not intended to provide complete redundancy of protection system components but rather provides a practical level of redundancy of protection system components to meet the performance requirements and expectations of the modern power system.

This section has four goals:

- Provide explanation of the selection of Protection System component failures
- Provide explanation of the review process for each of the Protection System component failures to determine if the approach introduced in this paper applies
- Provide examples demonstrating review of each Protection System component failure
- Provide some possible solutions that might fix a failure to comply to each of the Protection System component failures

> **<u>Proposed Requirement</u>**
> Transmission Owners, Generation Owners, and Distribution Providers that own Protection Systems installed on the Bulk Electric System shall assure that a failure of the following components of Protection Systems will not prevent achieving the BES performance requirements of the TPL standards. (The components are described in this section)

It is important to understand that an identical protective system design installed across a power system may cause different results with respect to the BES performance requirements in the TPL standards and the BES performance required for specific single Protection System component failures - AC Current Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, and Station DC Source. Consider the following examples of a strong source system with highly-concentrated generation and load (Figure 5–1) and a weak source station where there are only two lines and there is high source impedance (Figure 5–2).

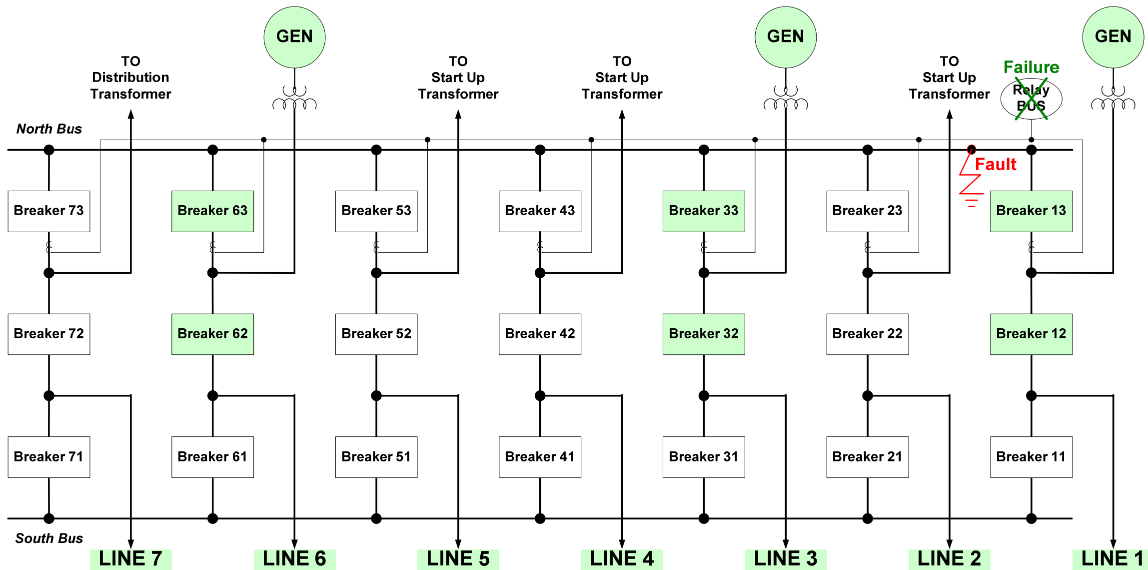

Figure 5–1 — Strong Source System One Line

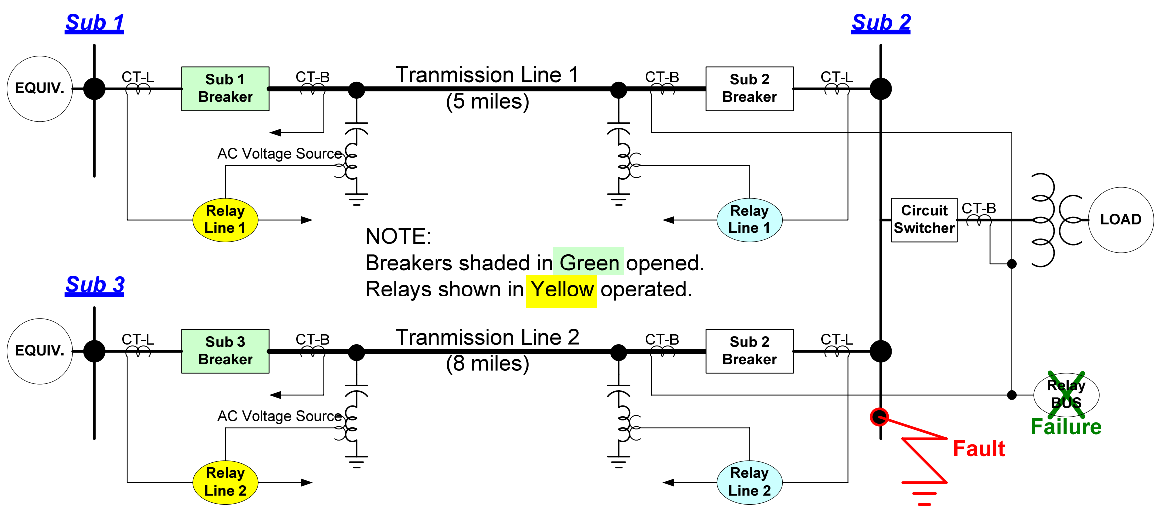

Figure 5–2 — Weak Source System One Line

Most transmission owners have standard applications that are applied for bus protection. The same identical protective scheme is used year after year for every bus protection application. The bus standard (for example) might be one high-impedance relay with one auxiliary lockout device. The approach introduced in this paper requires that the applicability of this design be tested to insure that the TPL standards' performance requirements are met for each application of this bus protection scheme.

Example 1 – Refer to Figure 5–2, Assume that the first bus to be studied is at Sub 2. Sub 2 has two transmission lines and a distribution transformer connected to the bus via a circuit switcher. The protection engineer investigates the performance of the bus protection in clearing a fault on the bus for a failure of a CT, or CCVT, or protective relay, or communications channel, or DC control circuit, or auxiliary trip relay, or breaker trip coil, and DC source. The result is that there is no violation of the TPL standards' criteria for a fault on the bus and a Protection System component failure. The remote line relays associated with the two lines at Sub 1 and Sub 3 trip and lockout each line serving Sub 2 fast enough to meet all TPL standards' BES performance criteria.

Example 2 – Refer to Figure 5–1, A second bus study with an identical bus protection scheme having three generators and ten lines on a strong source substation revealed that the TPL standards' criteria was violated due to low voltage and facility ratings after remote tripping caused the lockout of the three units and seven lines.

The above example illustrates that the review process is both a detailed review of a protection scheme on an individual application basis to determine fault clearing times for each applicable failure mode, with a planning study for each protection review to determine if the power system response still meets the BES performance requirements of the TPL standards for the clearing time determined by the protection review.

Any applicable owners must assure that specific components (AC Current Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, and Station DC Source) failing one at a time must not violate the BES performance requirements of the TPL standards for a worst-case fault on the facility covered by the Protection System with the failed component. The performance or application of the breaker failure relaying is not considered in this study. The Planning standards have maintained that the breaker failure scheme need not be redundant. This is because breaker failure scheme is a backup to the breaker operation. Therefore, a simultaneous breaker failure and a breaker failure scheme failure are considered an extreme contingency.

5.1 AC Current Source

Proposed Requirement
The failure or removal of any single **AC current source** and/or related input to the Protection System excluding the loss of multiple CT secondary windings.

Qualification: An event impacting multiple CT secondary windings (i.e., a failure of either a complete free-standing CT or an entire bushing with multiple CTs) would be detected and isolated by protection that is not dependent on these CTs.

At least two isolated and separate AC current sources (referred to as CT inputs) for Protection Systems are required to meet the proposed requirement for CT redundancy. Figure 5-3 shows a common arrangement that addresses the current measurement redundancy requirement. CTs are required to provide totally separate secondary AC current sources for each redundant Protection System. This is required so that a shorted, open, or otherwise failed CT circuit will not remove all protection elements requiring current. Figure 5–3 below shows the use of four CTs from a breaker with bushing CTs to separate the current measurement for the two Protection Systems for zones A & B.

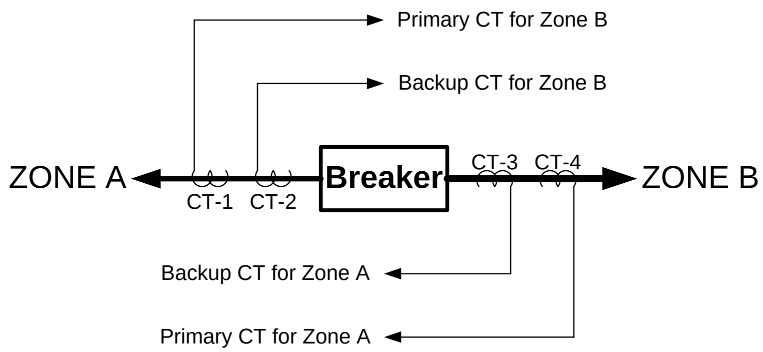

Figure 5–3 — Example of Redundant CTs

To assure that only one CT failure is addressed with each review, the proposed requirement would be qualified to indicate that an event impacting multiple CT secondary windings (i.e. – a failure of either a complete free-standing CT or an entire bushing with multiple CTs) would be detected and isolated by protection that is not dependent on these CTs. Good engineering practices should be followed in protection designs so that a failure of a complete free-standing CT Column, an entire bushing of a breaker or transformer with multiple CTs would cause a fault that would be detected and isolated by protection that is not dependent on these CTs. Some best practices include flashover protection for a free-standing CT column, and overlapping zones of protection for multiple CTs in adjacent or common wells.

The protective system failure of one CT circuit is a dependability type failure that makes all the relays associated with that CT inoperable. This situation can occur for a shorted or for an open CT circuit. The relays within this CT circuit or any auxiliary CT circuit connected to this main

CT must be considered as non-functioning. Each CT circuit must be considered to fail one CT a time. All the Protection Systems connected directly or through auxiliary CTs must be considered to be out of service. The worst-case fault in the protected zone must now be able to be cleared by either local or remote protection without violating the performance requirements in the TPL standards as introduced in this paper. The System Protection engineer will need to follow the methodology as outlined in Section 4.2 to assess the failure of each CT.

Example 1 – An old breaker with only one three-phase set of CTs with 5/5 auxiliary CTs is protecting a transmission line (Figure 5-4). The main CT and the auxiliary CT secondary circuits each contain a protective scheme for the transmission line. A failure of the main CT circuit can occur either by shorting the secondary at the breaker or at the point it enters the panel, or opening the CT circuit anywhere. The outcome of taking this one CT failure into account is that both transmission line relays will fail to operate for a fault on the protected line. The protection engineer must determine the clearing time for the worst-case fault on the protected transmission line. Typically a line end fault will result in the worst case clearing time. Note however, that a fault location with faster clearing may result in worse system performance.

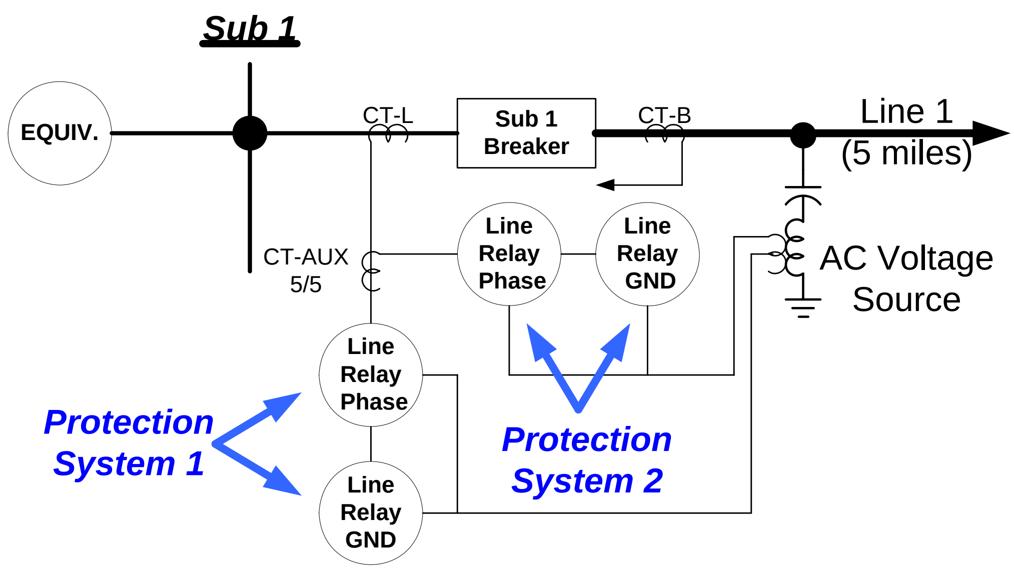

Figure 5-4 — Alternate CT Configuration with Single Point of Failure at the Main CT

Some items to be considered are:

- Are there other local relays at the substation that will clear the fault and what is the operating time of these relays?
- Are remote relays required to operate for this fault and what is the operating time of these relays?

- If the local substation has many lines then remote relays may not be able to sense a line end fault because the apparent impendence would be too great for the relay to detect.
- Sequential tripping of remote relays may be required to clear this fault.

A planning study must check to see if any violation of the BES performance requirements of the TPL standards occurs for the worst case fault on the line. If violations occur, the owner of this Protection System would need to find a solution for this example that will eliminate the violation caused by one CT circuit failure.

Possible solution for this example might be the addition of a new CT into the existing breaker, bushing slipover CTs, stand alone CT columns, or the replacement of the breaker with a breaker having additional CTs. Each of these solutions requires that a CT be provided with appropriate ratio, class, and thermal factor for the transmission line application.

Protective relays at the remote terminals can be adjusted or replaced so that they provide sufficient backup clearing times to meet the BES performance requirements of the TPL standards. If the relay reach is increased, the protection engineer should examine the relaying at the remote sites to make sure that they meet the loadability requirements of PRC-023-1. The last solution was presented to demonstrate that there are possible solutions other than the straightforward CT additions.

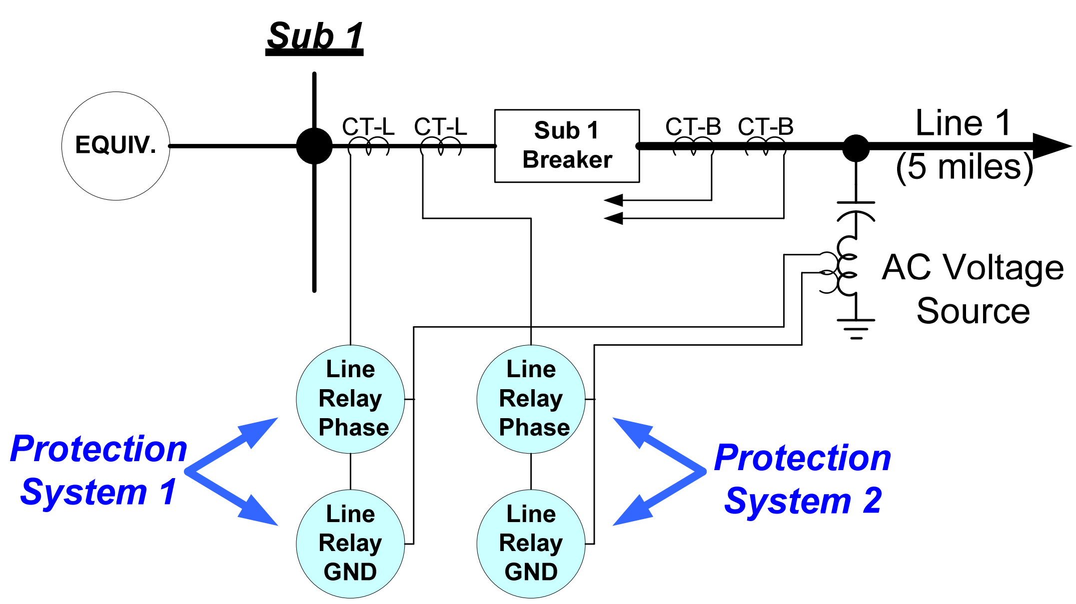

Figure 5–5 — Redundant CT Configuration

Example 2 – A transmission line is protected by a breaker with two dedicated CTs available (Figure 5–5) for line Protection Systems having similar functioning relays connected to each CT. Assume for this example that each relay can provide protection of the transmission line and does not violate the BES requirements of the TPL standards for a normal operation to clear a fault. Failing one CT at a time will result in the same clearing times as a normal operation because the remaining relay will not be impacted. Thus the approach introduced in this paper would not result in any violation of its BES performance requirements in the TPL standards and the owner of this Protection System meets the requirement for CT redundancy.

5.2 AC Voltage Source

> **Proposed Requirement**
> The failure or removal of any single secondary **AC voltage source** and/or related input to the Protection System when such voltage inputs are needed excluding the complete loss of an entire CCVT, VT, or similar device with multiple secondary windings.
>
> Qualification: Separate secondary windings of a single CCVT, etc, can be used to satisfy this requirement. An event impacting multiple AC voltage sources (i.e. – a failure of an entire CCVT, VT, or similar element) will be detected and isolated by other protection that is not dependent on these voltages.

At least two separate secondary windings supplying voltages for Protection Systems are required to meet the proposed requirement for AC voltage source redundancy when such voltage sources are required to satisfy the BES performance required in the TPL standards. This is required so that a shorted, open, or otherwise failed voltage circuit will not remove all protection elements requiring voltage. This level of redundancy is required only if the BES performance cannot meet the performance requirements of the TPL standards when AC voltage is unavailable to all Protection Systems applied to the protected zone.

Figure 5–6 below shows a potential device with two independent secondary voltage windings. The two secondary voltage sources are utilized independently by the two protective relay systems meeting the proposed requirement. Both Protection Systems in Figure 5–6 require voltage measurements to perform their protective functions and must have separate secondary sources as illustrated. The proposed requirement eliminates the possibility of a single point of failure in the Protection Systems requiring voltage measurements to perform their intended function. The proposed requirement **does not** prevent loss of voltage measurement to the protective devices in the event of the failure of the main CCVT, VT, or similar device. Loss of AC potential to relaying can cause the relaying to be more sensitive to remote faults and could cause the relay system to over trip.

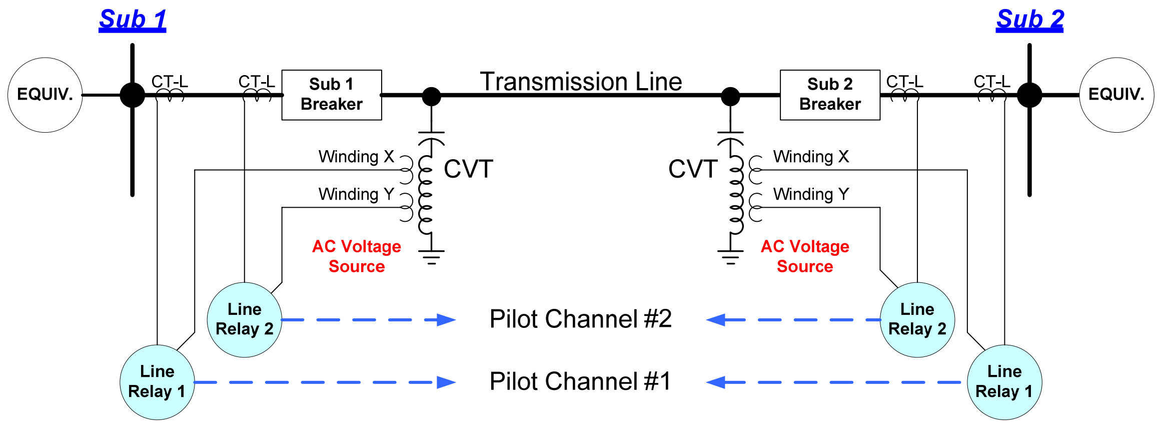

Figure 5–6 — AC Voltage Inputs

To minimize the effects of a failed AC voltage source, the redundant Protection System can use protective devices that do not rely on AC voltage measurements to respond to system disturbances. Substituting a Pilot Wire or Current Differential protective scheme for the relay 2 in Figure 5-6 would also be a method that would meet the proposed requirement without requiring the use of the second potential secondary. To assure that only one VT winding failure is addressed with each review, the proposed requirement would be qualified to indicate that separate secondary windings of a single CCVT, etc, can be used to satisfy this requirement.

The protective system failure of one CCVT, VT, or similar device, creates a failure for Protection Systems depending on Loss of Potential feature chosen. The proposed requirement is based on the fact that potential source failures result in an increased chance of tripping without fault or over-tripping during a fault in the area; not failure to trip. This is an additional reason why the proposed requirement does not require multiple three-phase sets of CCVTs, VTs, or similar devices. As discussed further below, the consequence of an over-trip will need to be reviewed to ensure is does not cause violation of any BES performance requirements of the TPL standards.

Each secondary voltage source failure should be analyzed to determine the Protection System performance for the fault in the protected zone that results in the worst BES performance. The proposed requirement of must be met unless the Protection System with the failed potential source can still perform its intended protection function, or the local or remote Protection System responding to the above failure has a clearing time that results in meeting all the BES performance requirements of the TPL standards. If the relay will over-trip then the Protection System performance should be analyzed for faults within the over-trip zone that results in the worst electrical system performance to determine whether all the BES performance requirements of the TPL standards will be met for the over-trip case.

Thus, one potential secondary circuit can be sufficient for a given zone of protection when both relays for this zone require potential inputs, provided that all BES performance requirements of the TPL standards will be met for all faults within or external to the protected zone when the single AC voltage source fails.

The use of the Loss of Potential (LOP) feature of some relaying schemes can be utilized to change to an alternate setting. If this alternate setting group will result in BES performance that meets the requirements of the TPL standards then no further actions are required. This feature can have both phase and ground non-directional overcurrent elements activate for the LOP condition and operate at a definite time. The time might be picked to allow any high-speed systems time to clear a fault in adjacent protection zones while operating much faster than remote zone two timer settings. A best practice is to utilize the LOP feature to provide an alarm to a 24/7 manned dispatch center which can initiate an investigation of the problem.

Example 1 – A transmission line has two Protection Systems and has one set of three-phase potential devices with two secondary windings as separate sources. The failure of one secondary potential source does not impact the operation of the overall protection of the line. Both Protection Systems provide the same performance, so the failure of either secondary potential source does not increase the clearing times.

Example 2 – The same Protection Systems as in the case above, but with only one secondary winding connected to both relays. For this example, failure of the secondary potential source removes both relays from normal operation. In this case it is required to determine whether all BES performance requirements of the TPL standards will be met for all faults within or external to the protected zone when the single AC voltage source fails. In this example the primary microprocessor relay has been set to trip on special non-directional current elements that are activated for loss of potential. The microprocessor relay is set to ensure tripping for all faults on the protected line, which results in over-tripping for faults external to the protected line for loss of potential. A planning study must determine that the BES performance meets all performance requirements of the TPL standards when tripping for faults on the protected line is initiated by the Loss of Potential feature on the primary relay, and when the Loss of Potential function on the primary system over-trips for faults external to the protected line. Note that LOP elements area not required to meet relay loadability requirements of standard PRC-023-1.

These examples demonstrate two of the ways that the line Protection System can be designed to meet the requirements introduced in this paper.

5.3 Protective Relay

Proposed Requirement
The failure or removal of any single **protective relay** that is used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.

Each element of the electric system must be protected by at least 2 relays. These relays can be located at the same terminal or may be located at different terminals, but both relays must provide the same performance and clearing times for faults on the element. The protection engineer must examine the failure or the removal of one of these protective relays at a time to determine if there is a violation of BES performance required by the TPL standards for the worst case fault condition. The review process requires the removal of each local protective relay one at a time for each protective zone to determine the clearing time provided by either other local or remote backup protective relay schemes for the worst-case fault in that protection zone. The second part of the review process requires a planning study be completed to determine if any the TPL standards' performance requirement violations occur for the clearing time determined from the worst-case fault in the protection zone with the failed relay.

Example – Refer to the general examples in the opening paragraphs of section 5.0 (figures 5-1 and 5-2). These two examples described a bus Protection System that consisted of one high-impedance relay and one lockout auxiliary device that were identical for two very different applications. Both cases utilized remote backup Protection Systems to clear the worst-case bus fault. Example 1 concludes that remote impedance relaying has a sufficient clearing time, trips Line 1 and line 2 and will not cause any the TPL standards' performance requirement violations. Example 2 from Section 5 concludes that the number of system elements lost or the time required to clear this fault causes BES performance requirement violations of the TPL standards to occur with respect to facility ratings, thermal or voltage. These examples demonstrate clearly how a protective relay failure can impact the BES and why it is important to apply appropriate redundancy to Protection Systems to minimize the impact of a Protection System component failure.

A possible solution to overcome the violations in Example 2 could be the addition of a second bus protective scheme that eliminates the dependence on remote backup for a protective relay failure. The additional relay must be installed in such a manner as to not cause it to fail simultaneously due to any of the other seven component failure modes in the proposed requirements.

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5.4 Communication Channel

Proposed Requirement
The failure or removal of any single **communication channel** and/or any single piece of related communications equipment, as listed below, used for the Protection Systems when such communication between protective relays is needed to satisfy BES performance required in the TPL standards.

- Communications functions for communications-aided protection functions (i.e. pilot relaying systems).
- Communications functions for communications-directed protection functions (i.e. direct transfer trip).

The communication systems for each protective relay must remain independent from each other as they are transmitted to the opposite terminal when the proposed requirement is applicable.

The proposed redundancy requirement for independent or separately dependable communications is required when the Protection System cannot meet the BES performance requirements of the TPL standards without utilizing communication-aided protection. Refer to Section 4.1 case # 3 for an example. This requirement acknowledges that failure-tolerant communications may be achieved either by designing the application with no common-modes of failure or by designing the application such that common-modes of failure will not prevent the Protection Systems from clearing faults to satisfy the BES performance requirements of the TPL standards in the planning review for the protection zone under review.

Fully independent communication channels are the hardest elements to provide for redundancy when pilot channels are required to meet the BES performance requirements of the TPL standards. It is recognized that some types of dual communications schemes have common modes of failure that are rare in occurrence; those limitations are generally accepted. The design of the overall Protection System must take such limitations into account even when communications channels are "redundant." For instance, if the same communication technologies are used, it is recommended that the relay schemes selected have minimal channel-dependency in order to trip successfully for fault conditions. Many other considerations, such as the performance of the communications during faults and the impact of weather conditions on the performance of the communications, need to be considered in the design of the Protection System.

Some acceptable communication schemes are:

- Two power line carrier systems coupled to multiple phases of the line.
- Two microwave systems and paths with multiple antennas on a common tower.
- Two fiber paths between terminals (two fibers in the same cable are not acceptable)
- Two separate communication systems of different technologies and equipment (e.g., fiber optic and digital microwave).

Figure 5–7 illustrates two independent communication aided Protection Systems with direct transfer trip schemes. The figure indicates that the two schemes are Directional Comparison Blocking (DCB) and Permissive Overreaching Transfer Trip (POTT), but there are many other types of high-speed communication aided protective schemes available. A communications aided system is provided for each Protection System and includes direct transfer trip for breaker failure. The communication schemes need to be independently designed and implemented between terminals in order to meet the proposed redundancy requirement.

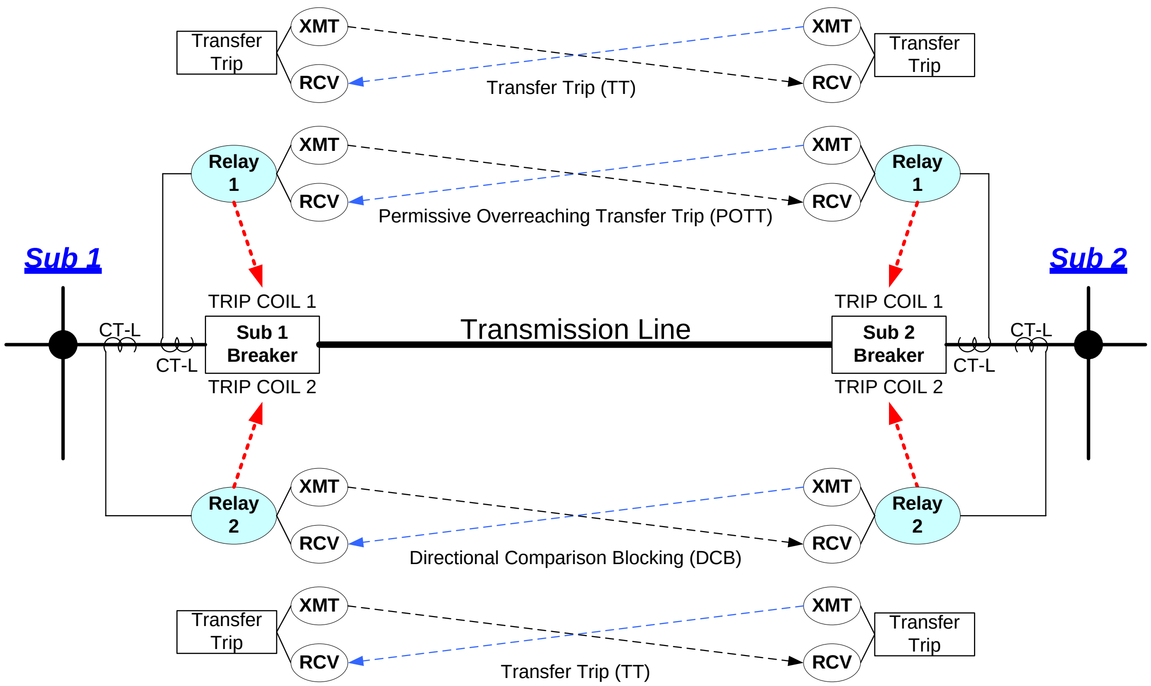

Figure 5–7 — Communication System

Dual pilot relaying may not be necessary to meet BES system performance requirements of the TPL standards. Non-pilot relaying may be able to satisfy the BES performance requirements of the TPL standards for some applications when the critical clearing times increase as the fault is moved further from the local terminal. This may require special planning studies that might result in eliminating the need for dual pilot relaying. These studies and assessments must be done on a periodic basis or whenever system changes are made that might alter the ability of non-pilot relaying to satisfy performance requirements. The Protection System communication only needs to be redundant for power system responses that require high-speed clearing for the worst-case fault in order to meet the BES performance requirements of the TPL standards.

The review process requires failing the communication channel to determine if the critical clearing time for the worst-case fault within the zone requires dual pilot relay systems in order to meet the BES performance requirements of the TPL standards. A planning study must be performed to determine the critical clearing time for meeting all the BES performance requirements of the TPL standards. When the clearing time required to meet BES performance requirements of the TPL standards cannot be achieved without communication-aided protection, then the need for independent and redundant communication channels is required.

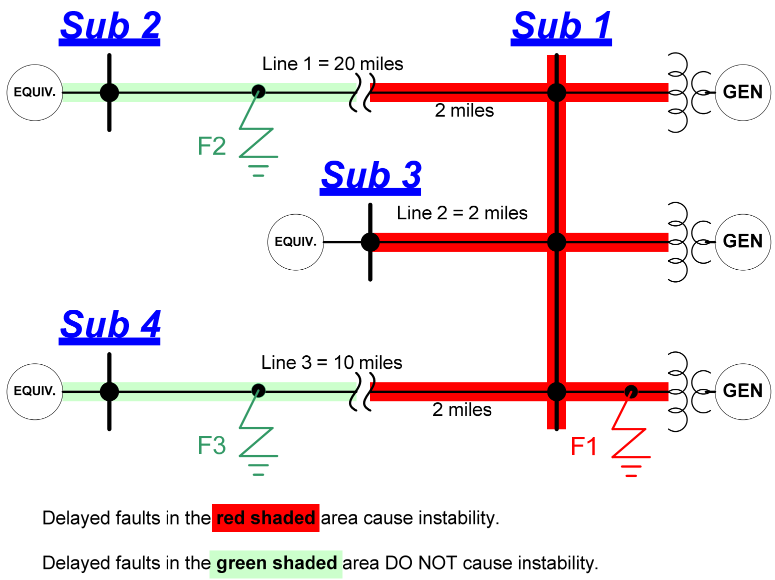

Figure 5–8 — Faults Near a Generating Station

Example 1 – Figure 5–8 illustrates 4 substations of a larger electric system. Sub #1 has three large generating units and a critical clearing time of 8 cycles for stability for faults close to the generators. Faults in the red area, as shown on the drawing, will cause instability if not isolated within 8 cycles. Faults in the green area, as shown on the drawing, will not cause instability for delayed clearing times up to 25 cycles. The line Protection Systems and the breaker failure system have been designed for each transmission line in order to meet the critical clearing time for stability of these three generators. Dual high-speed pilot Protection Systems were utilized on Line #2 to meet the 8 cycle critical clearing time for both pilot and direct transfer trip for breaker failure. One communication medium was power line carrier and the other microwave. Line #1 and Line #3 have only one high-speed pilot Protection System and one step distance impedance relay. The step distance impedance relay must provide high speed clearing for all faults on the line within the red shaded area. Due to the short critical clearing time it was necessary to design two independent high-speed relaying schemes for line #2 to meet the BES performance requirements of the TPL standards.

Example 2 – If the power system can meet the BES performance requirements of the TPL standards while experiencing an over trip for a communication failure, then it would be possible to utilize dual on/off directional comparison blocking schemes (DCB) or equivalent. The sensing relays for the DCB schemes or equivalent must be set to cover for pilot and direct transfer trip channel failure without causing any 'Loadability' requirement violations.

5.5 DC Control Circuitry

> **Proposed Requirement**
> The failure or removal of any single element of the **DC control circuitry** that is used for the Protection System.

The proposed requirement would require mitigation for a failure of the DC control circuitry that is used by the Protection Systems. The DC control circuitry does not include the station DC supply (covered in Section 5.8) or the breaker trip coils (covered in Section 5.7) but is considered to be all the DC circuits used by the Protection System to trip a breaker. This section includes any DC distribution panels, fuses, and breakers. This requires DC control circuits to be independently protected and coordinated, for each redundant Protection System required. This requirement may precipitate the need for multiple trip coils (See Section 5.7).

If the DC control circuitry for each Protection System is not properly designed and implemented, all the protection for a power system element could be removed by the loss of one DC breaker or fuse. Each DC control circuit must be reviewed to ensure that this does not occur if it results in a violation of the BES performance requirements of the TPL standards. The object is to prevent the outage of all the necessary protection for any one failure of the DC control circuits except for the non- redundant battery and charger or trip coils which are covered in later sections.

The DC control circuitry has many failure modes. A short in the DC control circuit requires the operation of a protective device (DC breaker or fuse) to remove the fault resulting in the loss of all the Protection System components on the circuit simultaneously. An open in the DC control circuit removes all Protection System components associated with that circuit from service simultaneously. The DC control circuit for each Protection System must be reviewed to determine how the failure of each DC control circuit impacts the protection for each Element. In every failure mode the Protection Systems must meet the BES performance requirements of the TPL standards.

Figure 5–9 demonstrates three DC circuit methods. Example 1 on the left has only one main circuit with coordinated sub-circuits. This style control circuit does not meet the DC redundancy control circuit requirements because the operation of one DC breaker can remove all Protection Systems. Example 2 has two main circuits and coordinated sub-circuits and meets the proposed DC redundancy control circuit requirement when paired Protection Systems are connected to different breakers. Example 3 also meets the proposed requirement and is an example of a fully redundant and separate DC Supply and DC control circuit system when paired Protection Systems are connected to different DC panels and breakers.

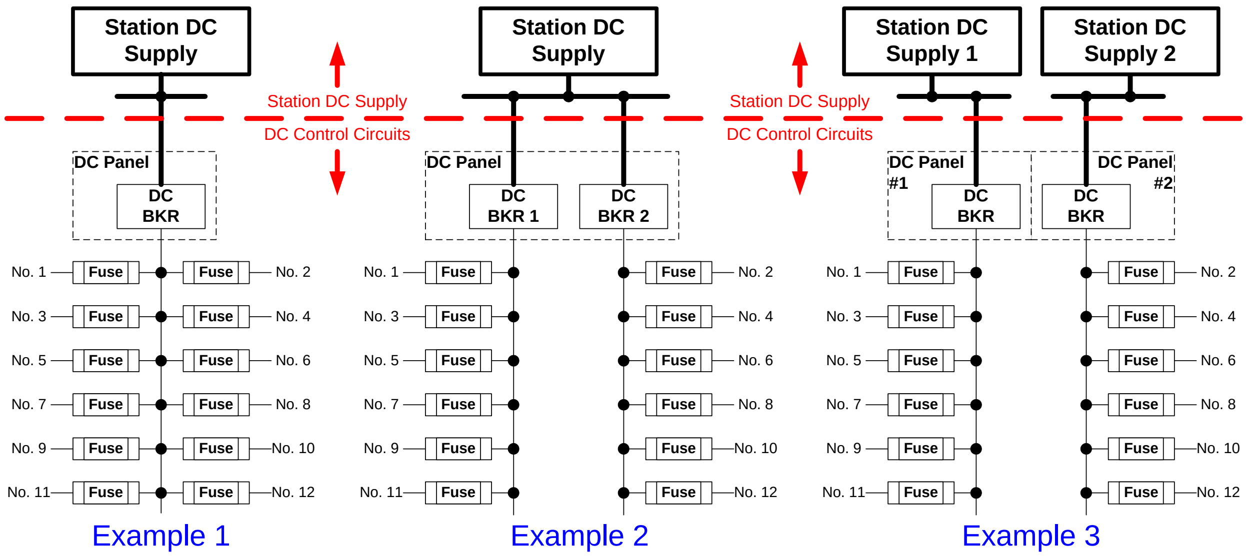

Figure 5–9 — Station DC Supply and DC Control Circuits Boundary

Figure 5–10 depicts a Protection System that employs redundant relays, AC supply and dual communication channels. The DC control circuitry is run from the DC Main that consists of a single 60-ampere breaker connected to fuse panel. Individual fuses that coordinate with the 60-ampere breaker are utilized to separate and isolate individual protective schemes. The opening of the 60-ampere breaker will remove all the local protection (both relays) that is protecting the transmission line. The loss of the Protection Systems on this transmission line must be tested based on Section 4 and the resulting BES performance must meet the BES performance requirements of the TPL standards for the worst-case fault within the zone or zones of protection that are removed from service by opening the 60-ampere breaker.

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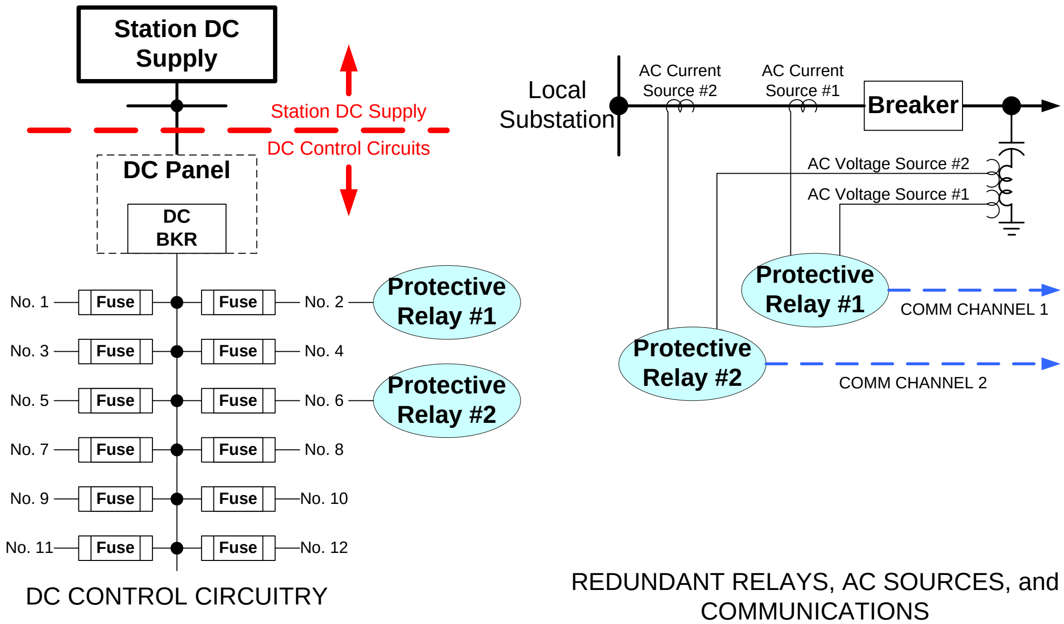

Figure 5-10 — Non-Redundant DC Control Circuits

If the example above caused a BES performance requirement violation of the TPL standards for the opening of the 60 amp breaker then it might be fixed by subdividing the 60-ampere circuit into two 60-ampere breakers fed from the Station DC supply. Each protective relay and associated DC control circuit should be separated with each one supplied from a different breaker so that the opening of a single breaker does not remove both Protection Systems.

5.6 Auxiliary Relay

Proposed Requirement
The failure or removal of any single **auxiliary relay** that is used for any of the above functions.

The auxiliary tripping relay is typically used to expand available contacts or provide common interface between dissimilar Protection Systems. This requirement focuses on the auxiliary tripping device to determine if its failure will violate the BES performance requirements of the TPL standards. The failure of auxiliary tripping relays and lockout relays in particular can contribute to prolonging abnormal power system condition. All auxiliary devices that impact the clearing time of faults on the power system must be checked to determine if their failure, one at a time, will cause any BES performance violations of the TPL standards.

Example – The examples described in the opening paragraphs of Section 5 consisted of one high-impedance protective relay and one lockout auxiliary device protecting a bus for a strong

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source system (refer to figure 5–1). In section 5.3 it was shown that a failure of the single bus relay caused a violation of the TPL standards. The bus Protection System also had only one auxiliary lockout relay. The failure of the auxiliary device or the protective relay for these examples will cause the same violations of the TPL standards and the loss of the same system elements. The solution is to add a second auxiliary relay and second protective relay and design the Protection System so that a loss of one auxiliary relay or one protective relay does not cause violations of the TPL standards. An additional solution would be to initiate breaker fail protection from all the protective relaying that operates the auxiliary relay. For this solution, the breaker failure time would need to meet the performance requirements of the TPL standards.

A related issue is the failure of an auxiliary device that provides both a trip and breaker failure initiate. Assessment of such a design must take into account that the failure of such a device will result in losing both the trip and breaker failure protection functions simultaneously. If that system cannot meet BES performance requirements of the TPL standards, the design must be changed to ensure that the failure of the auxiliary relay does not prevent tripping and breaker fail initiation.

5.7 Breaker Trip Coil

> **Proposed Requirement**
> The failure or removal of any single **breaker trip coil** for any breaker operated by the Protection System.

The relay systems and each trip coil must be operated from independent DC control circuits to prevent a single point of failure. Refer to Figures 5–9 and 5–10 in Section 5.5 for the DC control circuit review for the DC redundancy requirements.

This requirement focuses attention on the trip coil to make certain that its failure does not cause any violation(s) of the BES performance requirements of the TPL standards. The breaker trip coil provides the action that operates the breaker to clear the fault. Therefore, its failure to operate will cause breaker failure or delayed clearing times.

The Protection System outputs must be studied to determine if trips are issued to independent trip coils. If the Protection Systems issuing trip signals are duplicated to two independently operated trip coils then for this case the review is complete for the failure of one independent trip coil at a time because tripping will still be completed through the second path with exactly the same clearing time. However, if this is not the case then the clearing time for the worst-case fault in the zone(s) with the failed trip coil must be determined. A planning assessment must be made to determine if failure of the trip coil results in a violation of the BES performance requirements of the TPL standards.

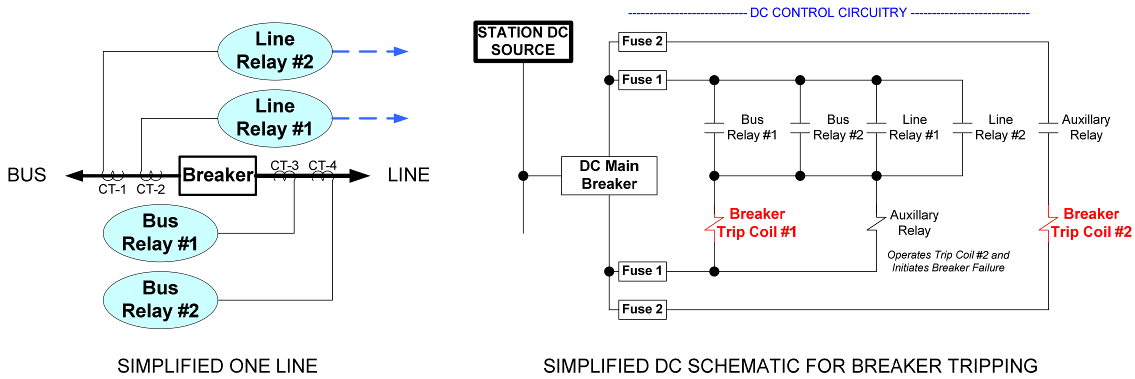


Figure 5–11 — Trip Coil Development

Example – Figure 5-11 depicts a breaker having two trip coils. The breaker is in the middle of overlapping zones of protection with 4 relay systems. Two of the systems are from line protection and two are from bus protection. The four relays will operate trip coil #1 and an auxiliary relay. The auxiliary relay operates trip coil #2 and provides breaker failure initiation (BFI). Since the two trip coils are not completely independently operated by all protection, a single failure can disable both trip coils and prevent BFI. This scheme has several single points of failure: the loss of Fuse 1, the tripping of the DC Main Breaker. Both of these failures will prevent tripping and breaker failure initiation. The procedure requires that the clearing time be determined for the worst-case fault in the line or bus zones, and a planning study completed to determine if the clearing time for the failure of the trip coils will result in meeting all the BES performance requirements of the TPL standards.

In the example above if a violation of the TPL standards did occur, one approach would be to make the two trip coils independent from one another. A properly designed breaker failure scheme meeting all the requirements of the TPL standards and the proposed Protection System redundancy requirements could be used to overcome a breaker with only one trip coil or two trip coils operated in parallel.

5.8 DC Source

> **Proposed Requirement**
> The failure or removal of any single station battery, or single charger, or other single **DC source**, where such losses are not centrally monitored for low voltage and battery open.

The station DC supply for tripping has traditionally been and still is a DC system consisting of a charger & battery. In order for this reliability proposed requirement to accommodate other new technologies the proposed requirement will include the wording “other single DC source”. The Station DC Source will cover the charger, station battery, or other DC source that is used for powering the Protection Systems and used for tripping.

The Station DC supply is usually designed to withstand short outages to the charging system or external supply. A charger failure results in the battery not being charged but it is assumed that the batteries have been fully charged prior to the loss of the charger. A properly sized battery should have the ability to provide the DC tripping and loading requirements of the substation design criteria. If neither DC source is battery based, at least one DC source must be able to provide the DC tripping and loading requirements of the substation equivalent to a battery.

However, there are failure modes of the DC system that can result in the immediate loss of all DC supply. Refer to figure 5–12 that depicts a typical station DC supply consisting of an AC supply, battery charger and batteries. The single station DC supply must be monitored continuously for the loss of critical components that would prevent total loss of the station DC supply. This monitoring must include battery open and low voltage and must be reported to a manned 24/7 operations desk for immediate response. A single battery & charger system must be monitored continuously for each of these failure modes. The use of monitoring significantly reduces the risk of having a complete battery failure at the time of a fault. It is important that the protection engineer understand the performance of the remote Protection Systems for the complete loss of the local station DC supply. Appendix A provides a discussion that illustrates the complete loss of station DC supply.

The protection engineer must determine if there is a violation of the BES performance requirements of the TPL standards for the loss of a single charger or single battery failure. If the failure of the single charger or single battery does not result in clearing times that violate the BES performance requirements of the TPL standards for the worst case fault condition, then no action is required. A substation that has two separate and redundant station DC sources meets this scenario. For every station DC supply, two tests must be considered to determine if the proposed requirement is met for a single source DC supply. The first test is to check and determine that the single station DC supply is monitored for charger failure, low voltage and open battery condition. The second test is to determine if the appropriate continuous alarming of the station DC supply exists at this station. The alarm must also be communicated to the manned 24/7 operation center.

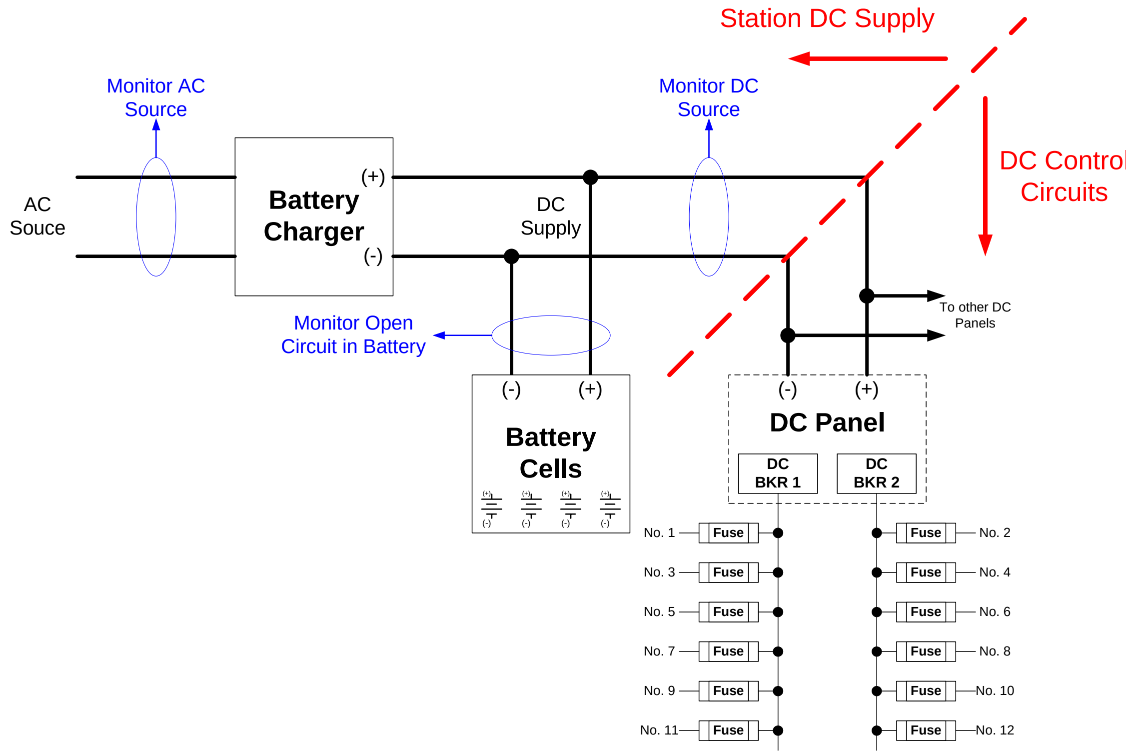


Figure 5–12 — Station DC Supply and Monitoring

Consider this example: Figure 5–1 above depicts a large strong source substation with many lines, generation and load. Figure 5–2 above depicts a weak source substation with two lines and some load. Assume that each substation has only one station DC supply that is not monitored for battery open. There is little doubt that the loss of a station DC supply for the large strong source substation in Figure 5–1 would have greater impact to the system than the loss of the station DC supply at the weak source substation in Figure 5–2. Worst case faults for these scenarios would result in a violation for the strong source example and could result in no violation for the weak source example. The strong source station requires a fix for the single charger or a single battery failure. A separate battery and charger could be installed at the strong source substation or battery open and low voltage monitors could be installed and connected to SCADA so that operators can be notified of a loss of the stations battery.

Appendix A – DC FAILURE (Loss of Station DC Supply)

Owners should be aware that the complete loss of the station DC Supply will cause the loss of all local tripping, SCADA control and observability, and could cause long delayed tripping.

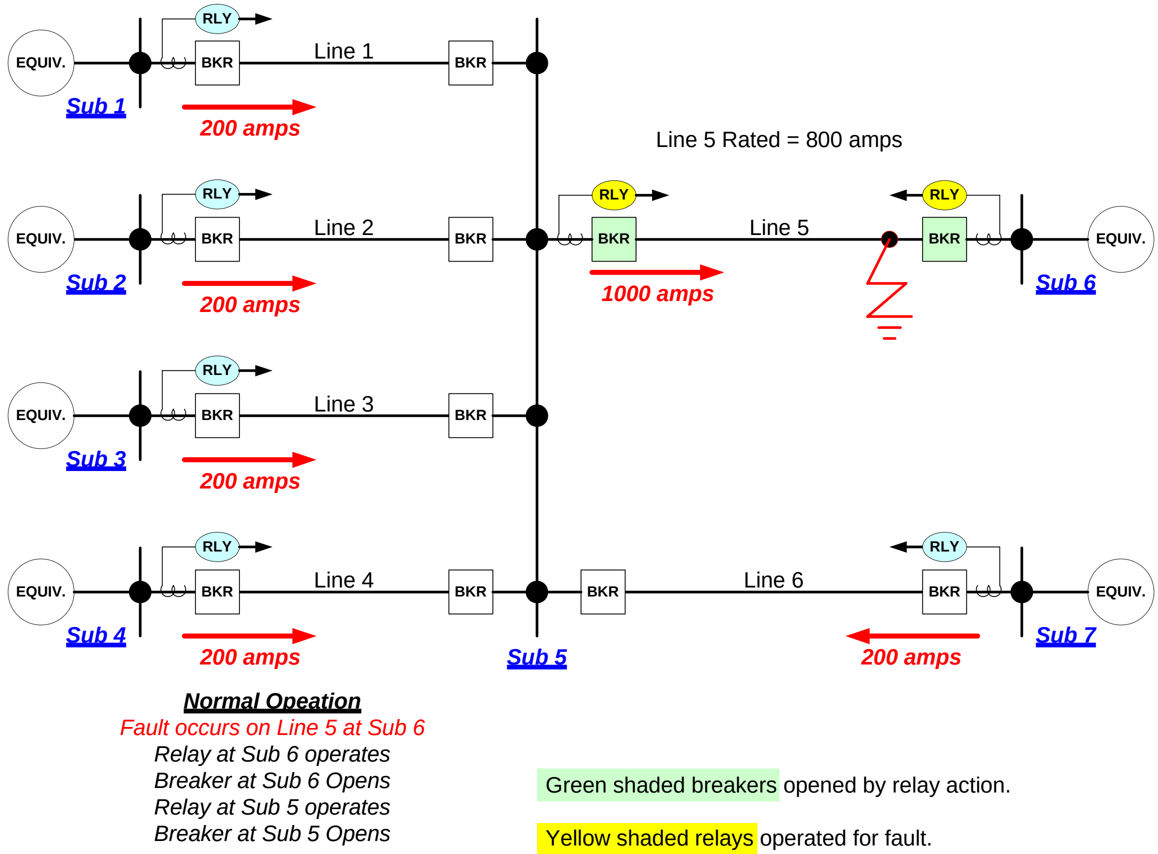
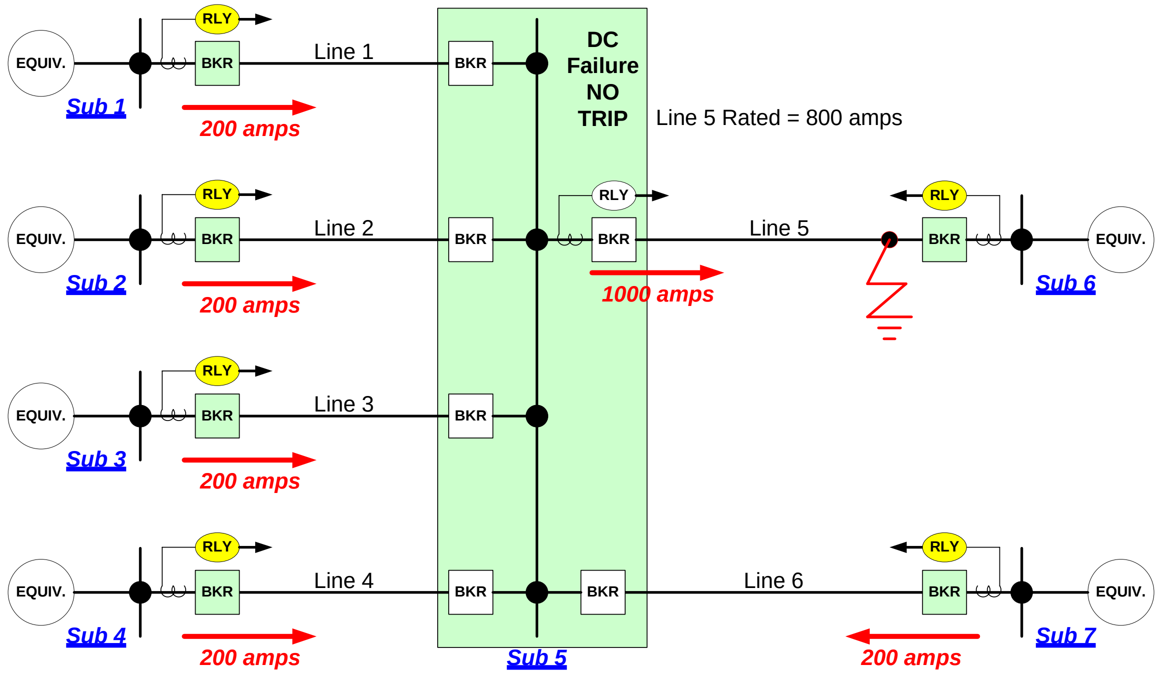


Figure A-1 — Normal Clearing

Consider the simple system in figure A-1. When all Protection Systems operate normally, a fault is cleared by the line relaying and breakers at both ends of the transmission line. However, consider that the station DC supply at Substation 5 (Sub 5) has failed and a fault occurs. There are two scenarios that can unfold. Figure A-2 depicts that all the remote line terminals have cleared to isolate the entire Sub 5. This assumes that the relaying at the remote ends of the transmission lines can sense this fault and if necessary sequentially operate one at a time to isolate this fault. This could take many seconds to isolate the fault. The worst case is that none of the remote relays senses the original fault and the line eventually sags and creates a fault closer to the substation until the remote relays sense the fault or an operator intervenes.

In those cases that the fault is not successfully cleared, there are several solutions that can be considered:

- Modify remote relay(s) settings to see fault but meet loadability (with load encroachment), and start sequential clearing sequence.
- Some relays could be replaced at the remote locations to accommodate sequential clearing.
- Modify the design at substation 5 to account for DC Battery failure:
  - Add a second DC supply to selective Protection Systems to provide isolation of fault or initiating sequential clearing.
  - Size the battery charger such that charger has the capability to supply enough energy to meet the required sequence of operations. This may include multiple trips and reclosings for line faults. Note: Care should be taken when using this option. The impact of depressed station service voltage as a result of the fault may limit the capability of the charger. Additionally, the worst case from a depressed voltage perspective will not be the far end fault which would make it necessary to identify the closest fault that would also go un-cleared.
  - Add redundant charger to account for DC battery charger failure. Note: Battery charger failure is an issue that must be addressed only if charger function is not remotely monitored and/ or the battery is not sized to accommodate the expected worst case response time.



LOSS of DC (operation)
Fault occurs on Line 5 at Sub 6
Relay at Sub 6 operates
Breaker at Sub 6 Opens
Fault current from Sub 5 is above rating of line
DC at Sub 5 is off and no tripping is available
Remote relaying must operate to protect line.

Green shaded breakers opened by relay action.

Yellow shaded relays operated for fault.

Figure A-2 — Complete Loss of DC with Remote Clearing

Appendix B – Excerpts from the 1997 NERC Transmission Planning Standards System Performance Requirements

Section III. System Protection and Control

A. Transmission Protection Systems

STANDARD

S2. Transmission Protection Systems shall provide redundancy such that no single Protection System component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I.

Measurement

M2. Where redundancy in the Protection Systems due to single Protection System component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or Protection System owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded Protection System installations. Breaker failure protections need not be duplicated.

Each Region shall also develop a plan for reviewing the need for redundancy in its existing transmission Protection Systems and for implementing any required redundancy. Documentation of the Protection System redundancy reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request.

Full (100 percent) Compliance Requirements

A. Where assessments (Standard III.A. S1, M1) show the need for transmission Protection System redundancy due to single Protection System component failures, the transmission or Protection System owner shall provide the required component redundancy to meet the system performance requirements of Standard I.A. and associated Table I. These redundancy requirements should include:

1) Separate ac current inputs
2) Separately fused dc control voltage
3) Other redundant components

Documentation of the planned implementation of the redundancy requirements should be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request (within 30 days).

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B. Each Region shall have a plan for reviewing the transmission or Protection System owner's assessments and for implementing the required component redundancy to promote consistency among its members. The Regional plan along with documentation of the redundancy reviews should be provided to NERC on request (within 30 days).

NERC 1997 Planning Standards Table 1

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Component(s)	Components Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A – No Contingencies	All Facilities in Service	None	Normal	Normal	Yes	No	No
B – Event resulting in the loss of a single component.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of a Component without a Fault.	 Single Single Single Single	Applicable Rating[a] (A/R) A/R A/R A/R	Applicable Rating[a] (A/R) A/R A/R A/R	 Yes Yes Yes Yes	 No[b] No[b] No[b] No[b]	 No No No No
	Single Pole Block, Normal Clearing: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) components.	SLG Fault, with Normal Clearing: 1. Bus Section 2. Breaker (failure or internal fault)	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned[d] Planned[d]	 No No
	SLG or 3Ø Fault, with Normal Clearing, Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned[d]	No
	Bipolar Block, with Normal Clearing: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing: 5. Double Circuit Towerline	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned[d] Planned[d]	 No No
	SLG Fault, with Delayed Clearing: 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	 Multiple Multiple	 A/R A/R	 A/R A/R	 Yes Yes	 Planned[d] Planned[d]	 No No

D[e] – Extreme event resulting in two or more (multiple) components removed or cascading out of service	3Ø Fault, with Delayed Clearing (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of a all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) for an event or condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems. ▪ Document measures or procedures to mitigate the extent and effects of such events. ▪ Mitigation or elimination of the risks and consequences of these events shall be at the discretion of the entities responsible for the reliability of the interconnected transmission systems.

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner.
b) Planned or controlled interruption of generators or electric supply to radial customers or some local network customers, connected to or supplied by the faulted component or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.
c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.
d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

NERC 2005 TPL Standards (Table I from TPL-001 – TPL-004)

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix C – System Protection and Control Subcommittee

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Standard Authorization Request Form

Title of Proposed Standard   Reliability of Protection Systems
Request Date: January 7, 2009
Authorized by Standards Committee: January 14, 2009

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name NERC System Protection and Control Task Force – See Attachment A	☒	New Standard
Primary Contact John Ciufo	☐	Revision to existing Standard
Telephone 416-345-5258 Fax 416-345-5406	☐	Withdrawal of existing Standard
E-mail john.ciufo@hydroOne.com	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.) To ensure that Protection Systems are applied in such a manner that Bulk Electric System (BES) performance goals are achieved.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
While the current TPL-series of NERC reliability standards generally address system design considerations related to system contingencies, those considerations are not adequate to address the complexities of Protection System performance for equipment failures within the Protection System itself.
 	
Protection system component failures may render a protective scheme inoperative, which could result in N-1 transmission system contingencies evolving into more severe or even extreme events. The proposed standard specifies which protection system component failures should be analyzed: AC Current Source, AC Voltage Source, Protective Relay, Communication Channel, DC Circuitry, Aux Trip Relay, Breaker Trip Coil, and Station DC Source.
 	
Three system disturbances since 2004 were each caused by failure of a single component of a protection system:
▪ Westwing outage June 14, 2004 – single aux. relay on 230 kV line failed
  o Tripped about 5,000 MW of generation
  o Could have collapsed Western Interconnection
▪ Broad River Disturbance – Aug. 25, 2007
  o Single lockout relay used to trip and initiate breaker failure timers on GSU
  o Loss of 7 generating units at 3 plants – 871 MW
  o Loss of 5 – 230 kV transmission lines
▪ PacifiCorp East Disturbance
  o Single lockout relay used to trip and initiate breaker failure timers on GSU
  o Loss of 8 generating units at 3 plants – 2,803 MW
  o Loss of 4 – 345 kV transmission lines
  o 274 MW interruptible and 200 MW firm load shed
 	
The proposed standard would require facility owners to have protection systems installed such that the failure of one of the specified components of a protection system would not prevent meeting the BES performance specified in the TPL standards.
 	
Mitigation of specified protection system vulnerabilities would have prevented each of the three identified disturbances from being more than an N-1 contingency.

Brief Description (Provide a paragraph that describes the scope of this standard action.) The proposed standard requires facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the BES performance identified in the TPL standards.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) Please see the attached Technical Reference Document "Protection System Reliability –

Redundancy of Protection System Elements," which provides technical background for the proposed redundancy standard. The proposed requirements would require the following:

Require Transmission Owners, Generation Owners, and Distribution Providers that own Protection Systems installed on the Bulk Electric System to assure that a failure or removal of any one of the following components of Protection Systems will not prevent achieving the BES performance requirements identified in the TPL standards:

- Any single AC current source and/or related input to the Protection System excluding the loss of multiple CT secondary windings.
- Any single secondary AC voltage source and/or related input to the Protection System when such voltage inputs are needed excluding the complete loss of an entire CCVT, VT, or similar device with multiple secondary windings.
- Any single protective relay that is used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
- Any single communication channel and/or any single piece of related communications equipment, as listed below, used for the Protection Systems when such communication between protective relays is needed to satisfy R1.
    - Communications functions for communications-aided protection functions (i.e., pilot relaying systems)
    - Communications functions for communications-directed protection functions (i.e., direct transfer trip)
- The failure or removal of any single element of the DC control circuitry that is used for the Protection System.
- The failure or removal of any single auxiliary relay that is used for any of the above functions.
- The failure or removal of any single breaker trip coil for any breaker operated by the Protection System (If a single trip coil is used, the breaker failure scheme DC must be independent of the breaker trip coil DC.
- The failure or removal of any single station battery, or single charger, or other single DC source, where such losses are not centrally monitored for low voltage and battery open.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
TPL-001-1, TPL-002, TPL-003, and TPL-004	The proposed protection system redundancy standard is intended to provide system protection performance that matches the BES system performance requirements of the TPL standards. Those standards are currently under revision.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

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Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS11
Date of Response: 06/17/2009
Responding Witness: IIP

Question No. :83
Subject: Substation Operations – System and Component Performance – Area Substation Reliability (Auto Ground Circuit Switchers) - 1. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the circuit switchers installed in 2008 at the following locations: a. Cherry St. transformer No. 4 b. E 29 St. transformer No. 4 c. E 36 St. transformer No. 2 2. What were the removal and other related costs for the Auto Ground Switch devices at the above area substations? 3. Provide the information requested in questions 1 and 2 for work completed in 2009 to date. 4. Provide the schedule and working estimates for the installation work at each of the area substations planned for 2009, 2010, 2011, and 2012.

Response:
Question 1.
Below is a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the circuit switchers installed in 2008 at Cherry St. Transformer No. 4, E 29 St. Transformer No. 4 and, E 36 St. Transformer No.2.

Note: The Cherry St. breakdown does not include the costs of the circuit switchers and other installation costs due to these costs being expended prior to 2008. Also, Gas Insulated Switchgear and Digital Transfer Trip equipment were installed at Cherry St. Transformers 3 and 4 in lieu of circuit switchers due to the lack of physical space, while meeting the reliability requirements.

Location	Labor ($)	Material & Supply ($)	Accounts Payable ($)	Indirect ($)
Cherry St. TR4	383,896		1,305,026	475,569
E29th St. TR4	612,898	11,850	52,570	323,982
E36th St. TR2	546,769	7,097	21,418	278,461

Contingency costs are not included as these are actual expenditures.

Question 2.
The removal and other related costs for the Auto Ground Switch devices at the above area substations are as follows:

Location	Labor ($)	Accounts Payable ($)	Utility Plant Retirement ($)
Cherry St. TR4	270,584	23,444	65,431
E29th St. TR4	22,458	14,064	57,095
E36th St. TR2	37,476		125,707

Question 3.
Below is the information requested in Staff 83.1-2 for work completed in 2009 to date.

Installation Cost:

Location	Labor ($)	Accounts Payable ($)	Indirect ($)
Cherry St. TR3	383,896	1,305,026	475,569

Removal Cost:

Location	Labor ($)	Accounts Payable ($)	Utility Plant Retirement ($)
Cherry St. TR3	270,584	23,444	65,431

Question 4.
Attached is the schedule for E29th St. and E36th St. installations through 2010, which are scheduled to be completed at the end of 2010. [I ASSUME THAT THIS IS NOT CONFIDENTIAL AS IT IS NOT TRANSMISSION INFO]

Cherry St. Transformer 1 and 5 equipment installations are in the design phase. Installation is expected to begin in the fall of 2010.

We are currently in the design and planning stage to commence work at a number of other stations that are expected to begin or complete work in 2010-2012 and beyond. A listing of these stations is provided below. Actual work plans and project schedules will be developed once detailed work scopes are finalized, and planning issues, such as outage and personnel resource availability, are determined.

Brownsville – Install 10 Circuit Switchers and a DTT System
W65th St. - Install 10 Circuit Switchers and a DTT System
Willowbrook – Install 2 Circuit Switchers and a DTT System
Sherman Creek Substation - Install 2 Circuit Switchers and a DTT System
Farragut – Install DTT System
Fox Hills - Install DTT System

E40th St. – Install 5 Circuit Switchers and 5 Circuit Interrupters
Ossining West - Install DTT System
Millwood West - Install DTT System
Fresh Kills - Install DTT System
West 49th St. - Install DTT System
West 42nd St. – Install DTT System
Washington St. – Install 1 Circuit Switcher and a DTT System
Cedar St. - Install DTT System
Dunwoodie - Install DTT System

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS11
Date of Response: 06/19/2009
Responding Witness: IIP

Question No. :88
Subject: Substation Operations – System and Component Performance – Facility Improvement Program - 1. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the facility improvement projects completed in 2008. Provide the same information for each project completed or in progress in 2009 to date. Explain specifically what each project encompasses and why it was necessary. Include the start and end dates for each project. 2. Explain the reasons(s) for the variations, delays, or changes in actual spending in 2008 versus the budget.

Response:
Question 1 – Please find the information requested in the file attached.

Question 2 – Actual expenditures for 2008 were $3,389,000 versus a budget of $6,000,000. This was primarily due to deferral of work due to a later than anticipated construction start for several projects. All of these projects are either in progress or completed. The deferred work included items such as the installation of load board quick connects at various substations, the refurbishment of retaining walls at the Webster Avenue and E147th Street PURS, the installation of a new water line at West 65th Street, and the modification of exterior walls at the East 36th Street Substation.

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Status	Location	Description	Justification	Scope	Start Date	End Date	Labor ($)	Materials ($)	Accts Payable	Others ($)	Indirects ($)	Subtotal ($)
Complete 2008	Eastview S/S	Storm Drain Improvement-Phase II, Modify Roadway to Prevent Water Accumulation	During heavy rainfall, puddle builds on the roadway in front of Eastview Substations main gate. This creates a stagnant water problem which becomes worse when it freezes. Thus creating a saftey issue because Eastview has a manual gate and the employees have to walk through this puddle of water or ice to open the gate.	The existing culvert/swale system, which directs runoff from adjacent properties, is no longer functional. This phase of the project includes re-establishing the swale/culvert system arour the existing sub-station, install a new sump with additional screening to reduce clogging, and connect all underground piping as required to integrate the drainage system.	Feb 2008	Dec 2008	125,002		217,121	0	108,392	450,515
Complete 2008	Fresh Kills S/S	Sump Pump Discharge Line Replacement	The Fresh Kills 345kv is prone to flooding due to a high ground water table, as well as run-off from rainfall. The sump pump discharge system allows proper station drainage of the Fresh Kills 345kv yard. Without a working drainage system the Fresh Kills yard is flooded, submersing the stations alarm and control wiring creating an unsafe working environment and potentially impacting the equipment reliability.	Installation of 120 linear feet of new 6'' & 8" drain lines to alleviate the water discharge problem and return station ground water discharge system to an operational status.	June 2005	Dec 2008	14,055		13,025	46,350	16,793	90,223
Complete 2008	Sedgwick Ave	Replace Drainage Piping	The piping in the basement of Sedgwick Ave. PURS cracked and usable beyond economical repair. When it rains, the basement floods, causing a personnel health and safety issue.	Install new piping and drainage.	Jan 2008	Dec 2008	4,522		37,400		12,563	54,485
In-Progress 2009	Washington st. S/S	Eliminate Storm Water Runoff from Station onto Adjoining Property	Rainwater from our property is percolating to A-Val Architectural Metal Corporation's property along the east side of property.	Cap the (4) four-inch retired cast iron pipe and install a new drainage trench which will connect to the existing catch basin. The new drainage trench will collect the rainwater and prevent it from soaking the ground and from percolating.	April 2009		4,203	0	632	0	2,504	7,339
Complete 2008	Sedgwick Ave	Sub Basement Upgrade	The boiler was previously retired in place and is no longer used fo any purpose. Building space and hot water heating has been completely replaced by electric space heaters and an electric hot water heater. Removal of the old retired boiler equipment and piping associated with the retired building heating system, the installation of new lighting fixtures and outlets in the sub-basemer and the removal of the existing electrical service in the basement, are beneficial to the continued safe operation and appearance of the cooling plant.	This project covers the removal of the retired boiler and piping from the sub-basement of the Con Edison PURS at 1823 Sedgwick Avenue, Bronx New York 10453. It also covers the installation of new lighting fixtures and outlets in the sub-basement and the removal of the existing electrical service in the basement. The access door to the sub-basement and frame shall also be replaced.			1,722			9,727	2,992	14,441
In-Progress 2009	Sedgwick Ave	Office Area Finish	The existing HVAC system for the supervisor's office at the Sedgewich Ave. PURS does not meet Con Edison's standards, or NYC building code. In addition the space does not meet the requirements of the NYS energy code, and is very uncomfortable.	Improvements will consist of installing a HVAC system, addition of insulation to walls, floor, and ceiling, and general upgrades. The new HVAC system will be a split system with th condenser mounted on the roof. The compressor unit will be mounted above the new hung ceiling. The HVAC unit will now provide heat, a/c and vitalization to the office space. The walls will be furred out making room for insulation, and running upgraded electric and communications. The floor will be raised to allow insulation, and communication wiring. There will be improvements to electrical equipment, communications equipment, and the addition of a fire alarm system. In general the office space will be brought up to code requirements, improving the quality, safety and working environment.	June 2008		2,300		23,344		6,440	32,084
Complete 2008	E. 63rd St. S/S	HVAC System/Safety Rails	The Control room at East 63rd Street Substation is not being properly cooled during the summer months. It is currently cooled by window type unit which are not enough to offset the cooling load. Temperatures sometimes reach higher than eighty-five degrees. Under this environment the operation and longevity of any electronic equipment is severely curtailed and working conditions are substandard. In addition the control building is heated by a forced hot air gas fired furnace installed in the Fire Pump Room. This installation of gas appliances in a Fire Pump Room does not comply with current NYC Building Code.	Install a "stand alone" packaged roof top air conditioning system, exhaust fans and unit heaters for the Control Building (Control rooms, locker room, Toilets, SOCCS Room, Test room, Fire Pump room and Battery rooms) to provide adequate cooling, heating and ventilation in accordance with industry standards. Hand rails will also be installed around the roof of the control building.	May 2008	Dec 2008	63,465	2,221	253,398	81	87,965	407,130
Complete 2008	Leonard St.	Install New 7.5 Ton Rooftop Air Conditioning Unit	The control room is cooled by two (2) window type ("thru the wall") air conditioners installed in the exterior walls. The computer data room is cooling by a window type ("thru the wall") air conditioner installed in the access wall to the basement stair in the fire pump room. This indoor installation does not provide for adequate heat rejection of hot air to the outside. It also undermines the 2 hour fir rating for the wall construction. The control room and computer data room are not being properly cooled during the summer months. These air conditioners are not enough to offset the room heat loads. Temperatures sometimes reach higher than eighty-fiv degrees. Under this environment the operation and longevity of any electronic equipment is severely curtailed and working conditions are substandard. The entire control building is heated by a forced hot air gas fired furnace installed in the heater room, which is situated inside the Fire Pump Room. The installation of gas piping for the heating appliance inside the fire pump room is not allowed under the current NY	Install a split (indoor/outdoor) air conditioning system to provide cooling, heating and ventilation in accordance with company and industry standards. The outdoor condenser unit with heat pump capability can be installed on the existing platform grating built over the control building roof. The indoor air cooling fan coil (with a supplemental electric heat) can be installed in the overhead of the computer data room. A system of ductwork (supply/return) will distribute conditioned air to the control room, computer data room and test room. Install independent electric space heaters in the toilet room, battery rooms, test room, and fire pump room in accordance with company and industry standards. The existing "thru-the-wall" air conditioning units for the control room will be retained as back-up systems. The "thru-the-wall" air conditioning units for the computer data, forced hot air gas furnace, gas piping, and hot air ductwork (supply/return) will be removed.The climate control improvements will increase system reliability and overall operator productivity.	Jun 2008	Dec 2008	57,612	975	218,087		79,340	356,014

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Status	Location	Description	Justification	Scope	Start Date	End Date	Labor ($)	Materials ($)	Accts Payable	Others ($)	Indirects ($)	Subtotal ($)
Complete 2008	W. 19th St. S/S	Install Ventilation System	At considerable capital cost, based on an agreement with Department of Environmental Conservation, we have upgraded th West 19th Street Substations high pressure fluid filled feeder pressurization skids. The skids were completely refurbished with state of the art controls and tank level instrumentation. This system/equipment was installed in the West 19th Street Substatio pump room and the cellar. This expensive equipment will fail and degrade at high temperatures. The required room temperature must be below 95 degrees Fahrenheit. This pressurizing plant is located in a room just above the cellar. The main steam heating supply pipe for West 19th Street Substation comes through the cellar of the substation. The heating system for the substation, which consists of a steam reducing station and condensate cooling coils located in the cellar, generates excessive amount of heat in the room. On several occasions, the temperature has bee recorded as high as 130 degrees Fahrenheit in the winter.	Installation of additional ventilation fans with associated mechanical, civil/structural, and electrical work is required to mitigate the problem. The original construction package was issued in 2002. A supplemental Addendum#1 to the construction drawings is being issued to resolve user comments, and provide new structural supports for the new ventilation equipment.	Aug 2005	Jan 2008	66,022	72	1,709	53,165	41,522	162,490
In-Progress 2009	E. 179th St. S/S	Upgrade Lighting	The existing lighting at the E.179th Street Substation is inadequate in the various relay sections and transformer vaults. This conditio is unacceptable, and could result in personal safety and well as security issues.	Upgrade the lighting, by replacing the old incandescent light fixtures with new with Energy Efficient sodium vapor light fixtures. This lighting system replacement will also include- new plug receptacles, ground fault interrupter receptacles, cable, conduit and a new lighting panel	Sept 2006		145,844	17,011	22,952	25	79,017	264,849
In-Progress 2009	Hell Gate	Upgrade Lighting	The existing lighting at the Hellgate and Sherman Creek Substations is inadequate in the various relay sections and transformer vaults. This condition is unacceptable, and could result in personal safety and well as security issues.	Upgrade the lighting, by replacing the old incandescent light fixtures with new with Energy Efficient sodium vapor light fixtures. This lighting system replacement will also include- new plug receptacles, ground fault interrupter receptacles, cable, conduit and a new lighting panel	Oct 2006		95,818	22,279	3,659		50,890	172,646
In-Progress 2009	Parkchester S/S	Upgrade Lighting System	The existing lighting at the Parkchester Substation is inadequate i the various relay sections and transformer vaults. This condition i unacceptable, and could result in personal safety and well as security issues.	Upgrade the lighting, by replacing the old incandescent light fixtures with new with Energy Efficient sodium vapor light fixtures. This lighting system replacement will also include- new plug receptacles, ground fault interrupter receptacles, cable, conduit and a new lighting panel	Feb 2008		47,037	5,895	12,195		28,022	93,149
In-Progress 2009	Sherman Creek	Upgrade Lighting	The existing lighting at the Hellgate and Sherman Creek Substations is inadequate in the various relay sections and transformer vaults. This condition is unacceptable, and could result in personal safety and well as security issues.	Upgrade the lighting, by replacing the old incandescent light fixtures with new with Energy Efficient sodium vapor light fixtures. This lighting system replacement will also include- new plug receptacles, ground fault interrupter receptacles, cable, conduit and a new lighting panel	Nov 2006		84,708	21,352	9,931		46,402	205,601
In-Progress 2009	Tremont	Upgrade Lighting System	The existing lighting at the Tremont Substation is inadequate in th various relay sections and transformer vaults. This condition is unacceptable, and could result in personal safety and well as security issues.	Upgrade the lighting, by replacing the old incandescent light fixtures with new with Energy Efficient sodium vapor light fixtures. This lighting system replacement will also include- new plug receptacles, ground fault interrupter receptacles, cable, conduit and a new lighting panel	June 2009							0
Complete 2008	Sherman Creek	Install Fencing Near Feeder 339 & 333 Pothead Stands (No Info)	Pothead stands 333 and 339 have low electrical clearance. Currently, there is no permanent barrier to protect those working i the vicinity of these two pothead stands. A permanent structure must be erected to address this safety concern.	A four (4) foot high chain link fence will be installed around the perimeter of the area of concern surrounding each pothead stand. Each fence will have two (2) swinging gates to provide access in the event that work needs to be done inside said areas. Concrete footings will be placed at the fence foundation and both fences to be grounded. The area will be regraded and additional warning signage indicating the low clearance condition will be placed.	Sep-08	Dec-08	16,522	1,321	37,810		19,675	75,328
Complete 2009	147th St. PURS	Replace Walls	The party wall has deteriorated to the point where it now needs replacement due to it being a safety problem. Upon inspection of the wall for structural defects, it was found that a large area of the stucco veneer about 20 feet long has become detached from the brick and is being supported by a steel column that is offset from the wall about 6 inches. Similar panels are bowing out in other sections of the wall and significant structural cracking can be see throughout the wall. The exterior of the wall on the side facing the abandoned lot has deteriorated beyond repair and requires replacement.	The wall requires demolition and replacement. The wall is not structurally load bearing but does provide security controls. Th new wall will be constructed of 12 inch CMU block to the height of the original wall with a cement parging on the interior and exterior of the wall for weatherproofing purposes. Reinforced 12" CMU block was chosen for this application due to its fireproofing and structural qualities. Additionally, installation of coping along the top of the wall will protect against water infiltration.	Sept 2008	Mar 2009	54,399		3,632		28,165	86,196
Complete 2008	E.179th St. S/S	Regrade Sidewalk	In E.179 Street Substation yard, the outdoor switchgear section buildings have concrete sidewalks outside and in front of the outdoor 13kV circuit breaker cubicles. These sidewalks function a a raceway to maneuver the truck type circuit breakers in and out o their respective cubicles. Over time settling of these concrete sidewalk raceways has occurred. The slope of the sidewalks now grades inward. When any water drainage does occur, the run-off will drain inward causing water intrusion into the switchgear cubicles.	Re-grade the concrete raceway sidewalks (~5 ft. X 300 ft. X ~2" thick) and slope the grade away from the buildings to avoid water intrusion in the cubicles. Scarify the top of existing concrete raceway sidewalks, and install new concrete as required to maintain a 32:1 slope (graded to drain away from the structures).	May 2007	Aug 2008	6,161		42,301		10,323	58,785

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Status	Location	Description	Justification	Scope	Start Date	End Date	Labor ($)	Materials ($)	Accts Payable	Others ($)	Indirects ($)	Subtotal ($)
In-Progress 2009	E. 13th St.	Fiber Optic Upgrade	The existing infrastructure is multimode fiber which connects from E13th St. Substation to East River Steam Station and uplinks to the East River Substation. The multimode fiber is old and has had several failed incidents. If this continues, the networkconnectivity will be compromised and E13th St connectivity will not be readily available since it has no redundant network. Also in order to upgrade E13th Substation to our new standard 3750 switch platform the old infrastructure needs to be upgraded. Once upgraded, E13th Substation will have diversity and redundancy. It will also have full gigabit (high speed) access which will allow for the installation of the new 3750 switches and wireless access.	Upgrade to Fiber Optic.	Dec 2007		72,776	1,858	140,152	8,605	75,167	298,558
In-Progress 2009	E. 179th St. S/S	Install Brimar Signs	Brimar type signage is a reflective faced type of corrosion resistant-aluminum sign, with a finished porcelain-enamel, blemish free, low gloss surface. This type of equipment signage is color coded dependant upon specific equipment type and voltage class, and is also guaranteed a minimum of 20 years to be 70% reflective. This improved type of signage will contribute to employee safety and reduce the potential risk of operating errors. Past operating errors have resulted in injury to employees, significant damage to Company equipment and loss of service to large numbers of customers.	Replace existing equipment signage with Brimar type signs.	Feb 2008		44,479		51,148	-10,438	33,426	118,615
In-Progress 2009	Various	Install Conect Boxes (Diesel Connections)	The stations listed currently do not meet our design guidelines for station light and power. The guideline is that, at least, one load board shall have a backup power source in case of an outage to their normal supplies. The design guidelines for area and transmission stations are shown on plates 303013 and 303014 (referenced in CE-ES-2002-6). The load boards of these stations have no backup supply. An outage to the two normal light and power supplies will cause a total outage to all of the stations light and power. Presently there is no simple method to connect the mobile diesel generator into the load board in order to supply the needed backup power. The addition of the quick connect box will now provide an easy connection point to simply plug the diesel in to keep the load board alive. The installation will be rated for full station operation so all equipment can be operated in a normal manner.	At each location identified, a diesel generator quick connect box will be installed. The box will be connected directly to one of the 120/208V AC load boards. The quick connect box will provide a quick and easily accessible means to connect the mobile diesel generator to supply back up power to the station's light and power system.	April 2008		265,002	6,474	170,048		197,758	639,282
Complete 2009	E. 36th St. S/S	Modify Exterior Walls	At many locations, the pre-cast panels are exhibiting signs of detioration and distress, including cracks and severe spalls at anchor locations. Anchors are corroding and several panels appear to have shifted outward significantly . Impending surface spalls were observed on the outside face of several panels above the sidewalk . Sealant joints between panels are also failing throughout.	Remove all the existing steel shims at the bottom of all of the concrete panels. Remove any intermediate connection betwee the panel and the concrete curb that were retrofitted subseque to the original construction. Repair the damaged ribs by removing damaged or cracked concrete and installing an appropriate repair mortar and reinforcement tied-in to the existing rib. Ribs shall be repaired in a manner that will put the in bearing on the curb, taking the entire vertical load of the panel. Provide a new connection between the repaired rib and the concrete curb at panels where cracks have compromised the integrity of the existing anchors. For panels that lack a vertically slotted hole at the top connection, provide new angle at the top of the panels with a vertically slotted hole.	July 2008	June 2009	84,752		177,372		80,834	342,958
In-Progress 2009	Webster Ave. PURS	Modify Retaining Wall To improve Drainage And Remove Damaged Areas	The outer side of the retaining wall, which faces the Metro North rails, is experienci ng varying degrees of damage. The wall has lost approx imately 20% of its original grout, and therefore has small cracks throughout the wall ; in addition there are two large cracks that extend through the height of the wall . On the stone w are clogged up weep holes which are not serving any purpose. There is no additional drainage system in place , therefo re the rainwater and groundwater is applying additional hydrostatic pressure to the wall.	The proposed solution is as follows - Pressure wash entire wal Repaint 20% of retaining wall to address missing grout and small cracks. Rout out large cracks and re-grout. Install tiebacks with anchor bolts along the cracks. Install a passive drainage system, by excavating soil in trench, pressure washin weep holes, installing Geotextile filter fabric, and refilling trench with crushed stone, to create a drainage system similar to a French drain. The entire procedure would require removing ar replacing the existing fence.	Nov 2008		13,754		649		5,025	19,428

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS15
Date of Response: 07/13/2009
Responding Witness: IIP

Question No. :129
Subject: Electric Operations – System and Component Performance – UG Sectionalizer Switches - 1. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the sectionalizer switches installed in 2008. Include the location and the start and end dates for each switch installed. 2. Explain the reasons(s) for the variations, delays, or changes in actual spending in 2008 versus the budget. 3. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the sectionalizer switches planned for 2009, 2010, 2011 and 2012. Include the location and the expected start and end dates for each switch installed.

Response:

1) Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the sectionalizer switches installed in 2008. Include the location and the start and end dates for each switch installed.

Company Totals				
		Actual Costs	Budget	Variation
Description*		2008	2008	2008
Labor		$121,662		
M & S		$566,310		
Accounts Payable		$717,182		
Other		-$202,817		
Indirect		$459,663		
Totals		$1,662,000	$3,210,000	-$1,548,000

*The Company does not budget by individual elements of expense by Region.
*Exhibit __ (IIP-4, p. 147), incorrectly shows 2008 expenditures of $1,622,000. Actual 2008 expenditures were 1,662,000.

The Company did not install any underground sectionalizing switches in Manhattan and Bronx/Westchester. In Brooklyn/Queens, underground sectionalizing switches were installed on the following feeders:

Feeder	Structure Number	Location	Installation Date
3B95	DM 77511	SUTTER AVE S/S 100' W/O GEORGIA AVE	4/5/2008
3B95	DM 77500	GEORGIA AVE W/S 100' S/O SUTTER AVE	4/5/2008
3Q90	DM 22383	99ST E/S 149FT N/O 58 AVE	1/16/2008
9B12	DM23775	WILLIAMS AVE. E.S. 213' S/O DUMONT AVE.	10/4/2008
9Q41	DM 22747	JUNCTION BLVD E/S 41FT SSC 45 AVE	3/27/2008
9Q41	DM 22636	55 AVE N/S 147FT EEC JUNCTION BLVD	3/27/2008
9Q42	DM 22751	N/S 55 AVE 22FT EEC JUNCTION BLVD	1/22/2008
9Q42	DM 22801	E/S JUNCTION BLVD 53FT SSC 45 AVE	1/22/2008

THIS ASKS FOR START AND END DATES OF THE PROJECT – WE ONLY HAVE INSTALLATION DATE.

2) Explain the reasons(s) for the variations, delays, or changes in actual spending in 2008 versus the budget.

In 2008, Bronx/Westchester initiated the work to install switches in the Riverdale Network. The project is behind schedule due to construction delays and is scheduled to be completed by fall 2009. This contributed $0.9 million of the $1.5 million variance for this program.

In 2008, for Brooklyn/Queens, the installation of new switches and the associated splicing was limited due to other higher priority work and man-power availability. In some cases, funding of other higher priority programs required the shifting of capital funds between programs. This contributed $0.6 million of the $1.5 million variance for this program.

3) Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the sectionalizer switches planned for 2009, 2010, 2011 and 2012. Include the location and the expected start and end dates for each switch installed.

Company Totals					
	Projected Costs ($000)				
Description	2009	2010	2011	2012	2013
Labor	$661	$792	$819	$824	$824
M & S	$786	$965	$1,004	$1,014	$1,014
Accounts Payable	$1,087	$1,348	$1,364	$1,368	$1,368
Other	$10	$11	$13	$13	$13
Indirect	$1,017	$1,240	$1,274	$1,281	$1,281
Totals	$3,562*	$4,356	$4,475	$4,501	$4,501

- The 2009 Plan is $500K less than the Exhibit as the reductions were made to reflect the Austerity requirements imposed under Case 08-E-0539.

The planned switch installations by Regions are as follows:

Brooklyn/Queens

Eleven switches per year will be installed in Brooklyn/Queens. The breakdown by year is as follows:

2009
Install:
4 switches in the Bay Ridge Network
1 switch in the Williamsburg Network
2 switches in the Borough Hall Network
2 switches in the Crown Heights Network
1 switch in the Flushing Network
1 switch in the Rego Park Network

Total Switches: 11
Start Project: 2009 End Project: 2009

2010
Install:
3 switches in the Bay Ridge Network
1 switch in the Williamsburg Network
2 switches in the Richmond Hill Network
2 switches in the Borough Hall Network

2 switches in the Rego Park Network
1 switch in the Flushing Network

Total Switches: 11
Start Project: 2010 End Project: 2010

2011
Install:
2 switches in the Bay Ridge Network
2 switches in the Williamsburg Network
1 switch in the Ridgewood Network
1 switch in the Borough Hall Network
2 switches in the Crown Heights Network (3B)
2 switches in the Flushing Network
1 switch in the Crown Heights Network (3Q)

Total Switches: 11
Start Project: 2011 End Project: 2011

2012
Install:
2 switches in the Williamsburg Network
2 switches in the Ridgewood Network
2 switches in the Richmond Hill
1 switch in the Borough Hall Network
2 switches in the Crown Heights Network (3B)
2 switches in the Rego Park Network

Total Switches: 11
Start Project: 2012 - End Project: 2012

<u>Bronx/Westchester</u>

Year 2009
Install: 10 switches in the Southeast Bronx Network
2 switches in the Northeast Bronx Network

Total Switches: 12
Start Project: July 2009 - End Project: December 2009

Year 2010
Install: 3 switches in the Southeast Bronx Network
4 switches in the Fordham Network
3 switches in the Northeast Bronx Network

2 switches in the West Bronx Network

Total switches: 12
Start Project: Spring 2010 - End Project: December 2010

Year 2011
Install: 2 switches in the Southeast Bronx Network
8 switches in the Fordham Network
2 switches in the Northeast Bronx Network

Total switches: 12
Start Project: Spring 2011 - End Project: December 2011

Year 2012
Install: 1 switches in the Southeast Bronx Network
6 switches in the Fordham Network
5 switches in the Central Network

Total switches: 12
Start Project: Spring 2012 - End Project: December 2012

The details on the switch locations and feeder numbers are being currently planned.

<u>Manhattan</u>

Two switches per feeder will be installed on 2 feeders in the Yorkville network each year in the fall of 2010, 2011, and 2012. The details on other switch locations and feeder numbers are being currently planned.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS15
Date of Response: 07/08/2009
Responding Witness: IIP

Question No. :130
Subject: Electric Operations – System and Component Performance – Shunt Reactor - 1. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the shunt reactors installed in 2008. Include the start and end dates for each shunt reactor installed. 2. Explain the reasons(s) for the variations, delays, or changes in actual spending in 2008 versus the budget. 3. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the shunt reactors planned for 2009, 2010, 2011 and 2012. Include the location and the expected start and end dates for each installation.

Response:

1. **Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for each of the shunt reactors installed in 2008. Include the start and end dates for each shunt reactor installed.**

The EOE breakout for the 2008 Shunt Reactor dollars is as follows:

110	Labor	$45,757
120	M & S	$32,193
130	Accounts Payable	$14,890
140	Other	$7,510
210	Indirect	$40,746
		$141,095

Shunt Reactors Installed in 2008

Shunt Reactors				
Program Year	**Feeder**	**Layout**	**Installation Start Date**	**Installation End Date (Alive Primary)**
2008	3B84	F06-2963-B	7/30/2007	5/31/2008
2008	1Q05	F06-9368-Q	5/6/2008	5/14/2008
2008	1Q17	F06-9370-Q	8/15/2007	5/9/2008
2008	1Q22	F06-9371-Q	8/23/2007	4/17/2008
2008	7Q64	E05-9803-Q	2/4/2008	4/10/2008
2008	1Q23	F06-9372-Q	8/15/2007	3/23/2008
2008	1Q13	F06-9369-Q	8/2/2007	2/23/2008
2008	1Q03	F06-9367-Q	8/30/2007	1/25/2008
2009	7Q82	F08-9322-16Q	12/14/2008	12/19/2008

2. **Explain the reasons(s) for the variations, delays, or changes in actual spending in 2008 versus the budget.**

The working being done on this program is dependent on the availability of equipment, scopes of other higher priority system reinforcement and reliability programs, and the availability of construction resources. In 2008, B/Q installed 9 shunt reactors and associated new vault installations. Work on the 2008/2009 transformer relief program and the installation of 127 new transformer vaults associated with this program diverted resources.

3. **Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the shunt reactors planned for 2009, 2010, 2011 and 2012. Include the location and the expected start and end dates for each installation.**

Please see excel sheet attachment for Brooklyn/Queens and Staten Island for the years 2009, 2010, 2011, and 2012. For 2009, 10 reactors are planned in B/Q. The 2009 plan is now $700,000 due to the austerity reductions. The Brooklyn/ Queens Shunt reactors installation is an ongoing project and does not have an end date. Staten Island plans on completing the two remaining reactor jobs (33kV feeders 33R02 and 33R37) in 2010.

Redacted

DPS 15 - Question: 130

Brooklyn Queens								
				[redacted]	**Projected Costs ($000)**			
EOE	**Description**		**2009 Forecast**	[redacted]	**2010**	**2011**	**2012**	**2013**
				[redacted]				
110	Labor		$101	[redacted]	$340	$382	$386	$386
120	M & S		$166	[redacted]	$570	$643	$650	$650
130	Accounts Payable		$202	[redacted]	$728	$831	$823	$823
140	Other		$46	[redacted]	$172	$196	$195	$195
210	Indirect		$185	[redacted]	$651	$736	$736	$736
				[redacted]				
	Totals		$700	[redacted]	$2,461	$2,788	$2,790	$2,790
				[redacted]				
Staten Island								
				[redacted]	**Projected Costs ($000)**			
EOE	**Description**		**2009 Forecast**	[redacted]	**2010**	**2011**	**2012**	**2013**
				[redacted]				
110	Labor		$0	[redacted]	$102	$0	$0	$0
120	M & S		$0	[redacted]	$72	$0	$0	$0
130	Accounts Payable		$0	[redacted]	$33	$0	$0	$0
140	Other		$0	[redacted]	$0	$0	$0	$0
210	Indirect		$0	[redacted]	$93	$0	$0	$0
				[redacted]				
	Totals		$0	[redacted]	$300	$0	$0	$0
				[redacted]				
Company Totals								
				[redacted]	**Projected Costs ($000)**			
EOE	**Description**		**2009 Forecast**	[redacted]	**2010**	**2011**	**2012**	**2013**
				[redacted]				
110	Labor		$101	[redacted]	$442	$382	$386	$386
120	M & S		$166	[redacted]	$642	$643	$650	$650
130	Accounts Payable		$202	[redacted]	$761	$831	$823	$823
140	Other		$46	[redacted]	$172	$196	$195	$195
210	Indirect		$185	[redacted]	$744	$736	$736	$736
				[redacted]				
	Totals		$700		$2,761	$2,788	$2,790	$2,790

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS15
Date of Response: 07/08/2009
Responding Witness: IIP

Question No. :132
Subject: Electric Operations – System and Component Performance – C-Truss – 1. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of C-Trusses installed in each of the years 2005, 2006, 2007 and 2008. 2. Provide a list of all C-Trusses installed in each of the years 2005, 2006, 2007 and 2008. Include the location, pole number, and the date of installation. 3. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of poles replaced in each of the years 2005, 2006, 2007 and 2008. 4. Provide a list for all poles replaced in each of the years 2005, 2006, 2007 and 2008. Include the location, pole number, and the date of installation. 5. For each of the years 2005, 2006, 2007 and 2008, explain the reasons(s) for the variations, delays, or changes in actual spending versus the budget. 6. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of C-Trusses installed in 2009 to date. 7. Provide a list of all C-Trusses installed in 2009 to date. Include the location, pole number, and the date of installation. 8. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of poles replaced in 2009 to date. 9. Provide a list of all poles replaced in 2009 to date. Include the location, pole number, and the date of replacement. 10. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the C-Trusses planned for 2009, 2010, 2011 and 2012. 11. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the pole replacements planned for 2009, 2010, 2011 and 2012.

Response:

1. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of C-Trusses installed in each of the years 2005, 2006, 2007 and 2008.

$000's	2005 *	2006	2007	2008
Labor	-	-	-	-
M&S	-	-	-	-
A/P	(3)	281	340	344
Indirects	-	68	78	89
Total	$ (3)	$ 349	$ 418	$ 433

**2005 - program dollars are understated because 2005 was the inaugural year for capturing dollars as a unique program. Some dollars were inadvertently captured under prior annual functional identifiers and are not readily available.*

2. Provide a list of all C-Trusses installed in each of the years 2005, 2006, 2007 and 2008. Include the location, pole number, and the date of installation.

Please see attached file, "dps15-132 Q2 and Q7 C-truss 2005-2009" for list of all C-Trusses installed in each of the years 2005, 2006, 2007 and 2008 as well as the location, pole number, and the date of installation.

3. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of poles replaced in each of the years 2005, 2006, 2007 and 2008.

$000's	2005 *	2006	2007	2008
Labor	62	98	60	230
M&S	64	99	62	98
A/P	-	84	293	384
Indirects	54	106	141	287
Total	$ 180	$ 387	$ 556	$ 999

**2005 - program dollars are understated because 2005 was the inaugural year for capturing dollars as a unique program. Some dollars were inadvertently captured under prior annual functional identifiers and are not readily available..*

4. Provide a list for all poles replaced in each of the years 2005, 2006, 2007 and 2008. Include the location, pole number, and the date of installation.

Please see attached file, "dps15-132 Q4 and Q9 Pole Replacement 2005- 2009" for a list of all poles replaced in each of the years 2005, 2006, 2007 and 2008 including the location, pole number, and the date of installation.

5. For each of the years 2005, 2006, 2007 and 2008, explain the reasons(s) for the variations, delays, or changes in actual spending versus the budget.

	$000's			
Year	Actual	Budget	Variation	Explanation
2005	177	1,500	(1,323)	program deferral due to work plan reprioritization
2006	736	1,458	(722)	program deferral due to work plan reprioritization
2007	972	1,417	(445)	program deferral due to work plan reprioritization
2008	1,434	1,400	34	

6. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of C-Trusses installed in 2009 to date.

$000's	May YTD 2009
Labor	-
M&S	-
A/P	409
Indirects	228
Total	$ 637

7. Provide a list of all C-Trusses installed in 2009 to date. Include the location, pole number, and the date of installation.

Please see attached file, "dps15-132 Q2 and Q7 C-truss 2005-2009" for a list of all C-Trusses installed in 2009 to date. Include the location, pole number, and the date of installation.

8. Provide a detailed breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the total number of poles replaced in 2009 to date.

$000's	May YTD 2009
Labor	48
M&S	8
A/P	12
Indirects	25
Total	$ 93

9. Provide a list of all poles replaced in 2009 to date. Include the location, pole number, and the date of replacement.

Please see attached file, “dps15-132 Q4 and Q9 Pole Replacement 2005- 2009” for a list of all poles replaced in 2009 to date including the location, pole number, and the date of replacement.

10. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the installation of the C-Trusses planned for 2009, 2010, 2011 and 2012.

$000's	2009	2010	2011	2012
Labor	-	-	-	-
M&S	-	-	-	-
A/P	665	515	518	511
Total	$ 665	$ 515	$ 518	$ 511

11. Provide a breakdown of the labor, material & supply, accounts payable, indirect, overhead, contingency, and any other related costs for the pole replacements planned for 2009, 2010, 2011 and 2012.

$000's	2009	2010	2011	2012
Labor	299	403	402	410
M&S	712	920	917	920
A/P	70	220	221	218
Total	$ 1,081	$ 1,543	$ 1,540	$ 1,547

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Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS35
Date of Response: 07/24/2009
Responding Witness: IIP

Question No. :322
Subject: Follow-up to DPS-202 – Area Substation Reliability (Auto Ground Circuit Switchers) - Provide a list of Auto Ground Circuit Switchers installed in 2005, 2006, 2007 and 2009 to date, similar to what Con Edison provided in attachment "DPS 21-202 Station Listing.pdf" in response to DPS-202, Question 2.

Response:
Please find the information requested in the attachment "DPS 35-322 CS and AGS Installations 2005-2009.pdf."

Please note that while reviewing this interrogatory, an error was found in the information provided in the response to DPS-21-202. The file attachment titled "DPS 21-202 Station Listing.pdf" incorrectly stated that 3 of 3 circuit switcher installations at Cherry Street have been completed and that the station is 100% complete. This is incorrect. 3 of 5 circuit switcher installations have been completed at Cherry Street. We are providing a corrected file attachment for the response to DPS-21-202.

Redacted

Years 2005 -2009

STATIONS IN PROGRESS - STATIONS IN DESIGN/CONSTRUCTION (2005-2009)

			WORK SCOPE		No. of banks for C/S Installation				No. Of Auto Ground Switches			
PROJ. NO.	**AREA SUBSTATION**	**Notes**	**PRIMARY**	**SECONDARY**	**TOTAL**	**COMPLETED**	**Date Completed**	**% COMPLETED**	**To be removed**	**Completed**	**Date Completed**	**% COMPLETED**
01496-88	West 42nd Street	1	CS	DTT	10	10		100%	5	0		0%
			CS			2	Nov-05					
			CS			2	Mar-06					
06542-91	East 29th Street	2	CS	DTT	5	2		40%	5	2		40%
						1	Dec-07			1	Dec-07	
						1	Dec-08			1	Dec-08	
06542-91	East 36th Street	3	CS	DTT	5	2		40%	5	2		40%
						1	Dec-07			1	Dec-07	
						1	Dec-08			1	Dec-08	
21626-05	Cherry Street	4	GIS	DTT	5	3		60%	4	2		50%
						1	Nov-07			1	Nov-07	
						1	Nov-08			1	Nov-08	
	East 13th Street	5							3	2		66%
										1	Nov-07	
										1	Nov-08	

Note 1 - The 6 banks not shown here were completed prior to 2005. Also, DTT was not initially part of the scope of this project. It was subsequently added, but will be done in a future year.
Note 2 - 2 of the 5 banks at E29th are completed. The remaining 3 are expected to be completed by May, 2010 (See DPS 21-202).
Note 3 - 2 of the 5 banks at E36th are completed. The remaining 3 are expected to be completed by May, 2010 (See DPS 21-202).
Note 4 - 1 of the 3 banks completed at Cherry St. was done prior to 2005. The remaining 2 will be completed in future years (pending replacement of the remaining 69kV feeders).
Note 5 - AGS switches at East 13th Street are removed in conjunction with associated outages during Cherry Street AGS removals.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS36
Date of Response: 08/10/2009
Responding Witness: IIP

Question No. :344
Subject: July 10 Update to Capital Investment - 1. Provide a revised Exhibit IIP-9 that reflects all known changes to the Company's T&D capital budget as described in the Company's July 10, 2009 preliminary update. 2. For each project and program provided in response to Question No. 1, provide the amount spent to-date in 2009 in an additional column. 3. Indicate, with an additional column containing an identifying notation, each project and program that reflects a revision to the Company's May 8 Rate Filing resulting from the Company's May 26, 2009 Austerity filing in Case 08-E-0539.

Response:
1. See attached schedule.

2. There are no expenditures in 2009 for any of the projects identified in the July 10th update filing that resulted in a change to the Company's T&D capital budget We would note that the Company's books in 2009 reflect a credit for overheads for the Astoria East-PAR and Corona-Series Reactor projects to adjust charges booked in 2008.

3. The schedules in the attachment also include a column to indicate which project/program cash flow was adjusted in 2009 as a result of the Company's May 26th austerity filing in Case 08-E-0539, and thereafter reflected in Company witness Rasmussen's supplemental testimony.

Redacted

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SUBSTATION OPERATIONS CAPITAL PROJECTS

		$000s						
	2009 - 2013 Five Year Plan						YTD Expenditures	Austerity Indicator
DESCRIPTION	**2009 Original Filing - May**	**2009 Revised**	**2010**	**2011**	**2012**	**2013**	**Jun-09**	**(Y)**
INCREASED CUSTOMER DEMAND	**$ 168,080**	**$ 163,080**	**$ 57,985**	**$ 25,300**	**$ 144,300**	**$ 126,300**	**$ (7)**	
Astor- Establish New Station	3,000	3,000						
Emergent Load Relief Program	1,300	1,300	1,300	1,300	1,300	1,300		
Newtown-Establish Station	92,780	92,780	42,000	-	-	-		
Parkchester-Install 3rd Cap Bank			-	1,000	1,000	-		
Parkchester-Install 4th Transformer			-	3,000	12,000	5,000		
Transformer Cooling Program	1,000	1,000	-	-	-	-		
Woodrow-Install Third Transformer And Fresh Kills Expand 138kV Station	25,000	25,000	12,185	-	-			
York-Establish New Area Substation	40,000	40,000	2,500	20,000	130,000	120,000		
GENERATION INTERCONNECTION*								
Astoria East-Install Phase Angle Regulator	3,000	-	-	-	-	-		
Corona-Install Series Reactor	2,000	-	-	-	-	-		
Sub-Total	**$ 168,080**	**$ 163,080**	**$ 57,985**	**$ 25,300**	**$ 144,300**	**$ 126,300**	**$ (7)**	
SYSTEM AND COMPONENT PERFORMANCE	**$ 164,996**	**$ 163,796**	**$ 185,450**	**$ 188,940**	**$ 193,370**	**$ 200,500**	**$ -**	
EQUIPMENT								
138kV Circuit Breaker Program Upgrade Program	11,700	11,700	11,700	11,700	11,700	11,700		
345kV Circuit Breaker Upgrade Program	5,000	5,000	5,000	5,000	5,000	5,000		Y
Circuit Switcher Replacement Program	500	500	500	500	500	500		
Condition Based Monitoring Equipment	250	250	250	250	250	250		
Corona - Breaker Addition (6S and 8X)	3,000	3,000	2,650	-	-	-		
Bus Section Upgrade - E. 63rd Street	-	-	-	-	-	-		Y
Elmsford-Upgrade of Elmsford - Substation	25,000	25,000	32,000	27,740	1,750	-		
Failed Equipment Other Than Transformers	1,500	1,500	1,500	1,500	1,500	1,500		
Failed Transformer Program	30,046	30,046	25,800	24,700	23,000	23,000		
Rainey-Replace Temp Transformer With Permanent	4,000	4,000	-	-	-	-		
Replace Disconnect Switches	4,600	4,600	4,600	4,800	4,800	4,800		
Replace Overdutied 13/27kV Circuit Breaker Programs	10,800	10,800	10,800	10,800	10,800	10,800		
Transformer Replacement Programs	13,000	13,000	20,500	20,000	21,000	21,000		
Sub-Total	**$ 109,396**	**$ 109,396**	**$ 115,300**	**$ 106,990**	**$ 80,300**	**$ 78,550**	**$ -**	
RELAY								
Control Cable Upgrade Program	1,000	1,000	1,000	1,000	1,000	1,000		
Relay Modifications	5,500	5,500	5,500	5,500	5,500	5,500		
Upgrade Analog Circuits To Digital Fiber	2,000	2,000	2,000	1,800	-	-		
Relay Protection System Redundancy (Single Point of Failure)	-	-	2,000	8,000	30,000	40,000		
Sub-Total	**$ 8,500**	**$ 8,500**	**$ 10,500**	**$ 16,300**	**$ 36,500**	**$ 46,500**	**$ -**	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
SUBSTATION OPERATIONS CAPITAL PROJECTS

		$000s						
	2009 - 2013 Five Year Plan						YTD Expenditures	Austerity Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	2010	2011	2012	2013	Jun-09	(Y)
MISCELLANEOUS COMPONENTS								
Additional G&T Devices	500	500	500	500	500	-		Y
Area Substation Reliability And Auto Ground Circuit Switchers	10,500	10,500	10,500	10,500	10,500	10,500		
Capacitor Cable Upgrade Program	3,000	3,000	3,000	3,000	1,000	-		
Category Alarms	2,250	2,250	2,250	2,250	2,250	2,250		
Construct Relay Enclosure Houses	1,500	1,500	1,500	1,500	1,500	1,500		
Corona Settlement	1,000	1,000	1,000					
DC System Upgrade Program	3,500	3,500	3,500	3,500	3,500	3,500		
Diesels / Black start Restoration (Phase 2) - Upgrade Station L & P	1,200	1,000	1,000	1,000	1,000	-		Y
E. 13th Street - Alarm Panel Replacement and Control Systems	-	-	-	1,500	4,500			
E179th Street-Substation - Bus Section Upgrade Program	-	-	6,000	15,000	25,000	32,000		
East River-Protection System Upgrade	3,500	3,500	3,500	3,100	2,520	-		
Facility Improvement Program	6,000	6,000	6,000	6,000	6,000	6,000		
Fire Suppression System Upgrades	-	-	6,000	6,000	6,000	6,000		
High Voltage Test Sets	3,500	3,500	5,000	3,000	4,000	4,000		
New Maximo Upgrade	400	400	-	-	-			
Rapid Restore Enhancements- Expansion of TOMS	200	200	200	-	-			
Reinforced Ground Grid	500	500	700	700	700	700		
Revenue Metering Upgrade	500	500	500	500	-			
Roof Replacement Program	3,000	3,000	3,000	2,100	2,100	3,000		
Small Capital Equipment Program	3,000	3,000	3,000	3,000	3,000	3,000		
Substation Loss Contingency	2,000	1,000	2,000	2,000	2,000	2,000		Y
Switchgear Enclosure Upgrade Program	500	500	500	500	500	1,000		
White Plains-Substation - Bus Section Upgrade Program	550	550						
Sub-Total	**$ 47,100**	**$ 45,900**	**$ 59,650**	**$ 65,650**	**$ 76,570**	**$ 75,450**	**$ -**	
ENVIRONMENTAL	**$ 15,000**	**$ 12,000**	**$ 15,000**	**$ 15,000**	**$ 15,000**	**$ 12,000**	**$ -**	
Environmental Risk Mitigation	3,500	3,500	3,500	3,500	3,500	3,500		
Pumping Plant Improvement	8,500	5,500	8,500	8,500	8,500	8,500		Y
PURS Supervisory Control & Data Acquisition	3,000	3,000	3,000	3,000	3,000	-		
Sub-Total	**$ 15,000**	**$ 12,000**	**$ 15,000**	**$ 15,000**	**$ 15,000**	**$ 12,000**	**$ -**	
PUBLIC AND EMPLOYEE SAFETY	**$ 4,100**	**$ 3,100**	**$ 4,000**	**$ 4,000**	**$ 4,000**	**$ 2,000**	**$ -**	
Security Enhancements	4,100	3,100	4,000	4,000	4,000	2,000		Y
Sub-Total	**$ 4,100**	**$ 3,100**	**$ 4,000**	**$ 4,000**	**$ 4,000**	**$ 2,000**	**$ -**	
STRATEGIC IT ENHANCEMENTS	**$ 5,705**	**$ 4,705**	**$ 5,500**	**$ 3,000**	**$ 2,500**	**$ 3,000**	**$ -**	
SOCCS - RTU Replacement	3,000	3,000	3,000	500	-	-		
Substation Automation Target Information System	2,000	1,000	2,000	2,000	2,000	2,000		Y
Technology Improvements	705	705	500	500	500	1,000		
Sub-Total	**$ 5,705**	**$ 4,705**	**$ 5,500**	**$ 3,000**	**$ 2,500**	**$ 3,000**	**$ -**	
TOTAL SUBSTATION OPERATIONS	**$ 357,881**	**$ 346,681**	**$ 267,935**	**$ 236,240**	**$ 359,170**	**$ 343,800**	**$ (7)**	

Shaded columns indicate rate years 2010 to 2012
***Note - Generation Interconnection - Credit for overhead corrections for charges booked in 2008**

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

		($000s)					
	2009 - 2013 Five Year Plan						Austerity Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	2010	2011	2012	2013	(Y)
STRATEGIC IT ENHANCEMENTS	**$ 16,050**	**$ 14,200**	**$ 9,350**	**$ 3,250**	**$ 4,150**	**$ 4,700**	
Bulk Power Improvements							
SOCCS Visualization	500	500	500				
District Operations Improvement							
System Operation Enhancements	250	250	400	300	300	300	
District Operator Task Managing System	250	250	400	250	300	300	
Operation Management System Enhancements	500	500	1,000	400	400	1,000	
EMS-Continuance							
EMS Reliability AECC and ECC	-	-	500	1,000	500	500	Y
Work Management Systems							
Distribution Orders Enhancements	250	250	250	300	350	300	
Outage Scheduling System	3,000	1,000	3,000				Y
Facilities / Utilities Improvement							
ECC/AECC Facility Security Enhancements	300	300	300			500	
Computer Room Renovation				500	1,000	1,000	
ECC UPS Battery Replacement					500	200	
Training Area Expansion	750	750	750				
Add Diesel Generator	1,900	1,900					
East Control Room Renovations	3,000	3,000					
Operator Console Replacement	1,000	1,600					
HVAC Upgrade - East Computer Room	500	500					
Command and Control Programs	250	-					
Operations Requirements							
Interface with NYISO	100	100	100	100	100	100	
Plant Information System	-	-	300		200		
Cyber Security	200	200	300	200	300	300	
Operations Network for EMS	300	100	250	200	200	200	
Control Center Phone System Replacement			1,300				
Max Generation / Fast Load Pick-up	400	400					
GT Remote Start System	600	600					
New EMS							
Replacement Program SOCCS-X Energy Management System	2,000	2,000					
Sub-Total	**16,050**	**14,200**	**9,350**	**3,250**	**4,150**	**4,700**	
TOTAL SYSTEM OPERATION	**$ 16,050**	**$ 14,200**	**$ 9,350**	**$ 3,250**	**$ 4,150**	**$ 4,700**	

Shaded columns indicate rate years 2010 to 2012

Redacted

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

		$000s					
		2009 - 2013 Five Year Plan					Austerity Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	2010	2011	2012	2013	(Y)
INCREASED CUSTOMER DEMAND	**$ 173,915**	**$ 173,915**	**$ 155,500**	**$ 63,000**	**$ 14,500**	**$ 19,000**	
Dynamic Feeder Rating	2,415	2,415	1,000	1,000	1,000	1,000	
Reconductor Feeders 45 and 46					10,000	18,000	
Vernon - W49th St-38M72 Upgrade	11,500	11,500	19,500	7,000	3,500		
179th St-Reinforcement - M29 (Includes Academy)	160,000	160,000	135,000	55,000	-	-	
Sub-Total	**$ 173,915**	**$ 173,915**	**$ 155,500**	**$ 63,000**	**$ 14,500**	**$ 19,000**	
SYSTEM AND COMPONENT PERFORMANCE	**$ 28,450**	**$ 22,450**	**$ 25,930**	**$ 33,910**	**$ 67,180**	**$ 72,000**	
Feeder 34182/4	-	-	-	-	3,000	-	
Manhattan-Replace 69kV Feeders On QBB	-	-	-	-	3,000	14,000	
Millwood-Replace Wood Poles W/Steel Poles	100	100					
Sprain Brook - W 49th St-Feeder M51	-	-	3,000	-	-	-	Y
Staten Island-Feeders 38R51 And 38R52	-	-	-	4,210	13,000	8,000	
Cable System Enhancement - Pothead Alarms	1,100	1,100					
Emergent Transmission Reliability	10,000	4,000	10,000	10,000	10,000	10,000	Y
Re-Conductor Dunwoodie – Sprain Brook Transmission Corridor	-	-	500	5,400	4,780		Y
Reinforce Hudson River Crossing Towers	3,000	3,000	1,800	1,800			
Replace 69M43/69M44 With 38M53 & 38M54	3,000	3,000					
Replace Feeder 69M41 & 69M45	-	-	1,000	5,000	18,000	18,000	
Replacement of Feeders 18001 & 18002	4,000	4,000	2,180	-	8,000	14,000	
Transmission Feeder Failures	5,000	5,000	5,000	5,000	5,000	5,500	
Upgrade Overhead 345kV Transmission Structures	2,100	2,100	2,200	2,300	2,400	2,500	
Replace potheads on Feeder 34184 (Astoria/Corona)	-	-	-	-	-	-	
Phasor Measuring Units for SCADA Real Time Operation	150	150	250	200	-	-	
Sub-Total	**$ 28,450**	**$ 22,450**	**$ 25,930**	**$ 33,910**	**$ 67,180**	**$ 72,000**	
ENVIRONMENTAL	**$ 1,225**	**$ 1,225**	**$ 1,175**	**$ 1,575**	**$ 800**	**$ 800**	
DEC Program Line	1,225	1,225	775	775			
Environmental Enhancements	-	-	400	800	800	800	
Sub-Total	**$ 1,225**	**$ 1,225**	**$ 1,175**	**$ 1,575**	**$ 800**	**$ 800**	
TOTAL TRANSMISSION OPERATIONS	**$ 203,590**	**$ 197,590**	**$ 182,605**	**$ 98,485**	**$ 82,480**	**$ 91,800**	

Shaded columns indicate rate years 2010 to 2012

DESCRIPTION	2009 Original Filing - May	2009 Revised	2009 - 2013 Five Year Plan 2010	2011	2012	2013	Austerity Indicator (Y)
Increased Customer Demand	**$ 307,827**	**$ 304,827**	**$ 249,823**	**$ 245,157**	**$ 250,658**	**$ 252,862**	
New Business							
New Business Capital	157,000	157,000	123,000	122,000	122,000	122,000	
Meter Installation	17,721	17,721	17,771	18,071	18,071	18,071	
Sub-Total	**$ 174,721**	**$ 174,721**	**$ 140,771**	**$ 140,071**	**$ 140,071**	**$ 140,071**	
System Reinforcement Area SS Load Relief							
Newtown	14,000	14,000	4,000	-	-	-	
Astor (Herald Sq. Transfer)	3,000	3,000	-	-	-	-	
Penn/Waterside	3,000	3,000	4,600	900	-	-	
Randall's Island	2,497	2,497	-	-	-	-	
City Hall to Cortlandt	1,100	1,100	200	-	-	-	
York to Lenox Hill	-	-	-	-	7,000	10,900	
Chelsea W 19th St. to Murray Hill	$ -	$ -	$ -	$ 3,700	$ 2,900	$ -	
Sub-Total	**$ 23,597**	**$ 23,597**	**$ 8,800**	**$ 4,600**	**$ 9,900**	**$ 10,900**	
Base Growth / Relief							
Primary Feeder Relief	34,289	34,289	33,583	32,525	32,122	31,874	
Network Load Relief Transformer Installations	50,860	47,860	45,620	46,158	46,460	46,460	Y
NonNetwork Fdr Relief (Open Wire)	9,820	9,820	8,605	9,125	9,226	9,474	
Overhead Transformer Relief	2,191	2,191	2,642	2,642	2,642	2,642	
Sub-Total	**$ 97,160**	**$ 94,160**	**$ 90,450**	**$ 90,450**	**$ 90,450**	**$ 90,450**	
Distribution Substation							
Distribution Substation Load Relief	-	-	-	-	-	1,000	
Spill Prevention Control Counter Measures		-					
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,000**	
Meter Purchase	12,349	12,349	9,802	10,036	10,237	10,441	
System and Component Performance	**$ 441,468**	**$ 392,719**	**$ 445,004**	**$ 434,116**	**$ 445,653**	**$ 434,929**	
Enhanced Reliability							
Elmsford Refurbishment	-	-	-	1,300	2,000	-	
59th Street Bridge Crossing	-	-	-	-	2,000	5,000	
(Primary) Cable Crossings	6,500	6,500	8,000	8,000	9,000	-	
HiPot	3,400	3,400	5,498	5,600	6,100	6,100	Y
PILC	32,035	27,085	33,000	33,000	33,000	33,000	Y
Transformer Remote Monitoring System 3rd Generation Transmitter	8,400	8,400	7,850	7,500	7,000	6,600	
Sectionalizing Switches	4,062	3,562	4,356	4,475	4,501	4,501	Y
Underground Secondary Reliability Program	40,374	24,274	37,422	40,866	50,009	50,546	Y
Secondary Open Mains	147,331	147,331	139,245	129,871	129,871	129,871	
Grounding Transformers	150	150	550	520	520	520	
Shunt Reactors	1,367	1,367	2,761	2,788	2,790	2,790	
Network Reliability	16,300	11,900	25,723	26,545	26,545	26,545	Y
Coastal Storm Risk Mitigation	2,446	446	3,000	3,000	3,000	3,000	Y
Transformer Purchase	148,152	134,152	144,606	138,640	138,750	137,250	Y
Sub-Total	**$ 410,517**	**$ 368,567**	**$ 412,011**	**$ 402,105**	**$ 415,086**	**$ 405,723**	
Distribution Substation Modernization							
Tap Changer Position Indicator System	81	81	132	-	-	-	
Temperature Gauges	150	150	100	100	100	100	
USS Transformer Replacement	370	370	600	600	600	600	
4kV USS Switchgear Replacement	2,200	2,200	2,200	1,200	1,200	1,200	
USS Life Extension Program	1,769	1,769	1,170	1,361	1,361	-	
Auto Reclose On Bank Breakers	154	154	250	250	250	250	
Facility Improvement	-	-	-	-	-	-	
Breaker Replacement	-	-	-	-	-	-	
Sub-Total	**$ 4,724**	**$ 4,724**	**$ 4,452**	**$ 3,511**	**$ 3,511**	**$ 2,150**	
Overhead Enhancement							
C Truss Program	1,746	746	2,058	2,058	2,058	2,058	Y
Autoloop Reliability	6,095	3,100	7,359	7,528	7,450	7,450	Y
Aerial (Okonite) Cable Replacement	3,021	3,021	2,532	2,544	2,550	2,550	
#4,#6 Self Supporting Wire	3,165	3,165	3,169	3,175	3,175	3,175	
Overhead Feeder Sectionalizing Program	2,631	2,331	3,189	3,202	3,452	3,452	Y
Automated Emergency Ties	-	-	750	750	750	750	
Overhead Feeder Reliability	752	752	750	1,125	1,125	1,125	
Rear-Lot Pole Elimination	1,437	437	1,437	1,437	1,437	1,437	Y
Enhanced 4kV Grid Monitoring	2,645	2,645	-	-	-	-	Y
4kV UG Reliability	475	475	1,111	1,111	1,111	1,111	
Overhead Conductor Clearance	-	-	1,630	1,622	-	-	
Overhead Secondary Reliability Program	500	500	500	500	500	500	
Targeted Primary DBC Replacement	504	-	800	800	800	800	Y
URD Cable Rejuvenation/Fault Indicator	806	806	806	198	198	198	
ATS Installation USS Reliability XW	2,450	1,450	2,450	2,450	2,450	2,450	Y
Total	**$ 26,227**	**$ 19,428**	**$ 28,541**	**$ 28,500**	**$ 27,056**	**$ 27,056**	

DESCRIPTION	2009 Original Filing - May	2009 Revised	2010	2011	2012	2013	Austerity Indicator (Y)
			2009 - 2013 Five Year Plan				
Emergency Response	**$ 138,523**	**$ 138,523**	**$ 126,525**	**$ 124,075**	**$ 124,075**	**$ 124,075**	
Emergency Primary Cable Replacement	59,625	59,625	56,056	53,856	53,856	53,856	
Overhead	15,992	15,992	14,267	14,267	14,267	14,267	
Emergency Service Replacement	19,743	19,743	20,053	20,053	20,053	20,053	
Street Lights	18,606	18,606	15,003	14,753	14,753	14,753	
Transformer Installation	24,557	24,557	21,146	21,146	21,146	21,146	
Total	**$ 138,523**	**$ 138,523**	**$ 126,525**	**$ 124,075**	**$ 124,075**	**$ 124,075**	
Public Safety	**$ 27,743**	**$ 21,168**	**$ 24,743**	**$ 29,416**	**$ 29,416**	**$ 29,416**	
Vented Manhole Cover	10,000	6,800	-	-	-	-	Y
Vented Service Box Covers	8,375	6,000	15,375	15,375	15,375	15,375	Y
Isolation Transformers	5,809	4,809	5,809	10,482	10,482	10,482	Y
Pressure, Temperature, and Oil Sensors	3,559	3,559	3,559	3,559	3,559	3,559	
Total	**$ 27,743**	**$ 21,168**	**$ 24,743**	**$ 29,416**	**$ 29,416**	**$ 29,416**	
Environmental	**$ 500**	**$ 500**	**$ 600**	**$ 600**	**$ -**	**$ -**	
Oil Minders	500	500	600	600	-	-	
Total	**$ 500**	**$ 500**	**$ 600**	**$ 600**	**$ -**	**$ -**	
Strategic IT Enhancements	**$ 27,878**	**$ 20,778**	**$ 28,598**	**$ 28,743**	**$ 26,290**	**$ 14,538**	
Outage Management System	4,600	4,600	2,300	2,300	2,300	-	
Meter Shop ADAMS	750	-	2,750	1,000	-	-	Y
4kV Load Shedding System	450	-	-	-	-	-	Y
ATS Automation	150	150	100	100	-	-	
Energy Services Case Management	-	-	3,000	6,000	3,000	-	
Power Quality (PQNodes) System Upgrade	1,650	1,650	1,650	1,145	-	-	
SCADA Systems Consolidation	800	800	950	600	100	-	
Electric Distribution Control Center Upgrades	3,000	500	3,000	3,000	3,000	-	Y
Mapping System Upgrades	2,900	500	2,000	2,000	12,000	12,360	Y
Distribution Engineering Workstation	500	-	500	500	500	-	Y
Grid Optimization	500	-	-	-	-	-	Y
Integrated System Model	1,750	1,750	1,750	1,500	-	-	
Decision Aids	500	500	500	500	-	-	
High Tension Monitoring Data Acquisition System	730	730	730	730	730	178	
RMS Data Acquisition System	1,000	1,000	1,500	1,500	500	-	
Heads Up Display	500	500	1,000	1,000	1,000	-	
Secondary Visualization Model	4,250	4,250	2,553	2,553	1,160	-	
Model Validation	2,000	2,000	2,000	2,000	2,000	2,000	
Joint Use Pole Life Cycle Management System	1,848	1,848	2,315	2,315	-	-	
Total	**$ 27,878**	**$ 20,778**	**$ 28,598**	**$ 28,743**	**$ 26,290**	**$ 14,538**	
Efficiency and Process Improvement	**$ 5,300**	**$ 5,300**	**$ 29,700**	**$ 28,200**	**$ 28,700**	**$ 17,100**	
Work Management Systems	5,000	5,000	29,700	28,200	28,700	17,100	Y
Accounting by Network	300	300	-	-	-	-	
Total	**$ 5,300**	**$ 5,300**	**$ 29,700**	**$ 28,200**	**$ 28,700**	**$ 17,100**	
TOTAL ELECTRIC OPERATIONS	**$ 949,239**	**$ 883,815**	**$ 904,993**	**$ 890,307**	**$ 904,792**	**$ 872,920**	
Shaded columns indicate rate years 2010 to 2012							

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS38
Date of Response: 08/07/2009
Responding Witness: IIP

Question No. :350
Subject: Electric Operations Capital – Efficiency and Process Improvements – Work Management System - In reference to Exhibit_ (IIP-8), pages 25 to 28 of 31: 1. When will the Phase 0 Assessment Team complete its "comprehensive report summarizing the work management business process changes, technology strategy, and project cost estimate and implementation plan"? 2. Provide the Phase 0 Assessment Team report, discussed above, if currently available. 3. Provide any and all data used to determine the $109 million estimated capital cost for the new work management system. This should include assumed software for installation; manpower source, type, and hours; type of computer hardware; expected overheads; the amount to cover contingencies and the reason for the contingency amount; license cost; schedule; industry survey; and any other items critical to the calculation of $109 million project cost.

Response:

Subject: Electric Operations Capital – Efficiency and Process Improvements – Work Management System - In reference to Exhibit_ (IIP-8), pages 25 to 28 of 31:

1. When will the Phase 0 Assessment Team complete its "comprehensive report summarizing the work management business process changes, technology strategy, and project cost estimate and implementation plan"?

1. Currently, the Work Management Solution Phase "0" Assessment team expects to complete the comprehensive report in December 2009.

2. Provide the Phase 0 Assessment Team report, discussed above, if currently available.

2. The report is expected to be completed in December 2009.

3. Provide any and all data used to determine the $109 million estimated capital cost for the new work management system. This should include assumed software for installation; manpower source, type, and hours; type of computer hardware; expected overheads; the amount to cover contingencies and the reason for the contingency amount; license cost; schedule; industry survey; and any other items critical to the calculation of $109 million project cost.

3. The Strategic Technology Roadmap Study, by the Micon Group, was the basis for the projected cost for calendar years 2010, 2011 and 2012.

The Micon Group derived the costs for capital and human resources based on:

- Industry experience at other large electric Investor Owned Utilities
- Recent product and service provider RFP responses

The estimate did not include costs for end user training or contingencies

Detailed Development of Rate Case Submission:

Cost [$Million]	2009	2010	2011	2012	2013	***2009-13***
2010 Rate Case Estimate		$ 29.7	$ 28.2	$ 28.7	$ 17.1	***$ 108.7***
Appropriation [Actual]	$ 5.0					
Micon Study (2010 Rate Case)						***Includes 2009 Approp***
Work Management Electric		$ 24.5	$ 10.5	$ 1.1	$ 2.3	
Compatible Units		$ 1.3	$ -	$ 8.3	$ -	
Maintenance & Inspect Electric		$ 0.4	$ 13.2	$ 14.0	$ -	
Asset Management Decision Support		$ 2.0	$ 2.0	$ 2.0	$ 1.5	
Process Change Improvements [a]		$ -	$ -	$ -	$ 10.0	
Contingency [b]		$ 1.5	$ 2.5	$ 3.3	$ 3.3	
Total		$ 29.7	$ 28.2	$ 28.7	$ 17.1	***$ 108.7***

Explanation

The $109 million estimate was based on the following assumptions:

- Development costs have been ruled 100% Capital
- Development costs include dedicated resources for a project team of Business and IR Technology personnel as well as consulting support for the Phase 0 Assessment and Business Technology Case Development
- Scope of the project expanded to address additional capabilities:
  - Work Initiation & Bundling
  - Design & Estimation
  - Pre-Requisite Management
  - Field Logistics
  - Work Execution

  - Contractor Delivery Management
  - Field Performance Management
  - Work Closure
  - Forecasting & Integrated Resource Planning
  - Contractor Strategy
  - Delivery Performance Management
- Consulting support will be required through 2013 for assessment, quality assurance, implementation, integration, and change management development.

(a) Process Change Improvements were not specifically addressed in the Micon Group Strategic RoadMap. It is anticipated that in order to effectively implement the technology solution, change management improvements will need to be initiated to facilitate and optimize the solution. This may include organizational changes, communication initiatives, training, benefits metrics, etc.
(b) Contingency was not a cost component of the Micon Group Strategy RoadMap. We applied a contingency factor of 10%.

Work Management System Resource Projection:

Resources [Man Years]	2009			2010			2011		
	Bus	Tech	Cont	Bus	Tech	Cont	Bus	Tech	Cont
Micon Study Solution 3A									
Work Mgt Electric	17.0	6.0		27.0	15.0	1.0	27.0	15.0	1.0
Compatible Units	22.0	3.0		0.0	0.0		0.0	0.0	
Mtce & Inspect Electric	17.0	6.0		22.0	3.0		21.0	14.0	1.0
Asset Mgt Decision Supp	15.0	4.0		6.0	3.0		6.0	3.0	
Total	***71.0***	***19.0***	***0.0***	***55.0***	***21.0***	***1.0***	***54.0***	***32.0***	***2.0***

Resources [Man Years]	2012			2013		
	Bus	Tech	Cont	Bus	Tech	Cont
Micon Study						
Work Mgt Electric	10.0	8.0	1.0	0.0	0.0	0.0
Compatible Units	0.0	0.0	0.0	0.0	0.0	0.0
Mtce & Inspect Electric	21.0	14.0	1.0	11.0	7.0	1.0
Asset Mgt Decision Supp	6.0	3.0	0.0	6.0	3.0	0.0
Total	***37.0***	***25.0***	***2.0***	***17.0***	***10.0***	***1.0***

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS38
Date of Response: 08/07/2009
Responding Witness: IIP

Question No. :351
Subject: Electric Operations Capital – Efficiency and Process Improvements – Work Management System - In Exhibit 70 (IIP-25) in Case 08-E-0539, the Company requested funding of $1.5 million, $13.5 million, and $18 million for 2009, 2010, and 2011 calendar years, respectively (see attachment DPS-351-08E0539 Exhibit_(IIP-25) page 1-2.pdf). In this rate case, the funding approved for 2009 has increased to $5 million and the funding requested for calendar years 2010, 2011 and 2012 has increased to $29.7 million, $28.2 million, and $28.7 million, respectively. Explain why there is such a drastic increase in expected cost for this project compared to what was filed in Case 08-E-0539.

Response:

In the 3rd quarter of 2008, a consulting group, the Micon Group, was brought in to review the strategic issues surrounding IT projects. Subsequently, in the 4th quarter of 2008, a Strategic Technology Roadmap Study was completed by the Micon Group. This study developed a high level cost summary and required resources for an Electric Operations focus on a work management solution. The recommendation from the Micon Group was to conduct a Phase “0” assessment to develop the Business Case, evaluate and select an optimum software package(s), develop a detailed Implementation plan and develop a Change Management plan for a work management system in Electric Operations.

In the first quarter of 2009, a Work Management System Phase “0” Assessment team was created. The team consists of 11 full-time business representatives, 6 IR representatives and also includes a team from a consulting firm with extensive work management implementation experience. This team is funded at the $5 million level for 2009.

The prior rate case submissions relating to Work Management Systems included a $65.3 million estimate, which was based on the following assumptions:

- Development costs were assumed to be 12% O&M and 88% Capital
- Development costs included allocated labor for IR Technology and Business support only
- Scope of the project was limited to addressing five core processes – Work Initiation, Design, Approvals, Labor and Material Charges and Closing

As explained in response to Staff 350, the $109 million estimate was based on the following assumptions:

- Development costs have been ruled 100% Capital
- Development costs include dedicated resources for a project team of Business and IR Technology personnel as well as consulting support for the Phase 0 Assessment and Business Technology Case Development
- Scope of the project has been expanded to address additional capabilities:
  - Work Initiation & Bundling
  - Design & Estimation
  - Pre-Requisite Management
  - Field Logistics
  - Work Execution
  - Contractor Delivery Management
  - Field Performance Management
  - Work Closure
  - Forecasting & Integrated Resource Planning
  - Contractor Strategy
  - Delivery Performance Management
- Consulting support will be required through 2013 for assessment, quality assurance, implementation, integration, and change management development.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS40
Date of Response: 08/19/2009
Responding Witness:

Question No. :372R
Subject: Projects approved in Case 09-E-0310 - In Case 09-E-03101, the Commission approved several Con Edison projects (see Appendix C of July 27 Order). For each Con Edison project approved in the July 27 Order, identify the corresponding project as proposed in the Company's initial filing in this proceeding by name, exhibit number, and page number. For example: Project Name as shown Project Name(s) as shown in Appendix C in Rate Filing Exhibit Page No. Dynamic Modeling & Visualization Secondary Visualization Model IIP-7 75 Model Validation IIP-7 78

Response:
Indicated below are names of projects included in both the rate filing and the Stimulus filing. Please note that the scope of work for these projects as set forth in the Stimulus filing is for work that is incremental to the work proposed for these projects in the rate filing.

Project Name as shown in Appendix C	**Project Name(s) as shown in Rate Filing**	**Exhibit**	**Page No.**
Dynamic Modeling & Visualization	Secondary Visualization Model	IIP-7	75
	Model Validation	IIP-7	78
UG Sectionalizing Switches	UG Sectionalizing Switches	IIP-4	145
OH Sectionalizing Switches	Overhead Feeder Sectionalizing	IIP-4	182
Remote Monitoring System	Transformer Remote Monitoring System 3rd Generation Transmitter*	IIP-4	143
	Pressure, Temperature and Oil Sensors	IIP-5	31
High Tension Monitoring	High Tension Monitoring Data Acquisition System	IIP-7	69

Note*: "RMS Data Acquisition System" IIP-7, Page 71 has been replaced with "Transformer Remote Monitoring System 3rd Generation Transmitter", IIP4, Page 143

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS41
Date of Response: 08/12/2009
Responding Witness: IIP

Question No. :379
Subject: Follow-up to DPS-130 – Shunt Reactor Program - 1. Provide a list of all shunt reactor installation work performed in 2009 to date. This list should include for each shunt reactor installed the location, the associated feeder and the installation date. 2. Update the shunt reactor program actual expenditures as of July 31, 2009.

Response:
See attached. (We would note that many of the projects noted in the response to question 1 are underway and the expenditures provided in question 2 reflect this on-going work.)

Redacted

DPS 41-379 Question 1

Shunt Reactors

Program Year	Feeder	Layout	kVA Rating	CM Comp	Install	Alive Primary
2009	1Q06	F06-9376-1Q	600	N/A	3/16/2009	3/28/2009
2009	6Q24	F08-9369-1Q	600	N/A	5/5/2009	5/6/2009
2009	9Q50	Z09-9503-Q	600	N/A	3/25/2009	3/31/2009
2009	10B64	Z09-1501-B	1000			
2009	4B12	Z09-1508-B	600			
2009	5B24	Z09-1502-B	300			
2009	5B25	Z09-1524-B	300			
2009	7Q85	Z09-9504-Q	600			
2009	7Q87	Z09-9516-Q	1000			
2009	9B05	Z09-9575-Q	1000			
2009	9B09	Z09-9520-Q	1000			
2009	9Q47	Z09-9515-Q	300			

DPS 41-379 Question 2

Company Totals			
EOE	**Description**		**July YTD Actual**
110	Labor		$43,613
120	M & S		$129,026
130	Accounts Payable		$23,675
140	Other		$170,627
210	Indirect		$158,391
	Totals		$525,331

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS41
Date of Response: 08/19/2009
Responding Witness: IIP

Question No. :380
Subject: Follow-up to DPS-167 – Aerial (Okonite) Cable Replacement Program - 1. Provide a list of all aerial (Okonite) cable replacement work performed in each of the years 2005, 2006, 2008 and 2009 to date. This list should include, for each aerial (Okonite) cable replaced, the location, total length and date of installation. 2. Update the aerial (Okonite) cable replacement program actual expenditures as of July 31, 2009.

Response:
1.

Aerial Cable Replacement

Layout No/ Project No	Location	Spans	Approx Length (feet)	Completed Date
E04-19224-W	Chester Ave., Summit St., Robert La. & Hartsdale Ave. Town of Greenburgh	17	1,850	Feb-05
F05-9313-Q	14 Ave, 160th St.	36	3,702	Dec-05
F05-9315-Q	Douglaston Pkwy, Little Neck	22	2,640	Jan-06
F05-9310-Q	33 Ave, 169th St.	58	6,046	Feb-06
F05-2996-B	Ave "I" from E.53 St. to E.58 St.	20	2,400	Apr-06
F05-7124-W	Secor Rd., Longfellow St., Lytton Ave., DobbsFerry Rd. W. Hartsdale Ave., Town of Greenburgh	69	8,670	Jul-06
F08-9332-Q	58 St., 52 Ave.	18	2,160	Nov-08
Z08-06335-W	5TH Ave., City of New Rochelle	14	1,810	Feb-09
Z08-06336-W	5TH Ave., City of New Rochelle	19	2,415	Feb-09
E08-12561-W	N. Broadway, City of Yonkers	5	635	Apr-09
F08-7118-W	W. Hartsdale Ave, S. Washington Ave., Central Ave., Town of Greenburgh	65	8,095	In Progress

F08-07138-W	Albany Post Rd., Village of Buchanan	12	1,460	In Progress
Totals		**355**	**41,883**	

Dollars expended do not necessarily correspond to when a project is cutover or completed. Many of these projects began in one year and were completed in the following year.

2. Note that the Aerial (Okonite) Cable Replacement program is a reliability program, and as with reliability programs generally, the majority of the spending is in the second half of the calendar year. It is also noted that the above $588,835 spent through July 2009 does not reflect additional expenditures incurred against this program in early August 2009. These costs will bring the total YTD costs for this program to $762,200.

Description	**YTD Actual July 2009 Expenditures**
Labor	65,756.20
M & S	282,934.85
Accounts Payable	45,885.36
Other	16,056.81
Indirect	178,201.49
Totals	**$588,834.71**

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS43
Date of Response: 08/19/2009
Responding Witness: IIP

Question No. :406
Subject: Substation Operations – System and Component Performance – Facility Improvement Program - 1. Describe in detail the rationale for increasing the 2009 through 2012 forecasted budgets versus the actual spending levels for 2004 through 2008? 2. In reviewing the Company's spending in 2008, it appears that the Company was not able to achieve its Facility Improvement Program budget goal. Explain how Con Edison expects to meet the more aggressive goal of spending twice as much more in each of the three rate years? 3. Update the Facility Improvement Program actual expenditures and the type of facility work performed as of July 31, 2009.

Response:
Question 1 –The rationale behind increasing the budget for this program was the recognition of an increasing backlog of large scale capital projects needed to maintain and/or improve substation facilities as well as to support the discontinuation of temporary office facilities to ensure the continued efficient deployment of personnel and provide a safe work environment for employees. As noted in Exhibit __ (IIP-4), work done under this program line addresses items such as facility structural issues, lighting, large scale drainage modifications, paving, fencing, and HVAC. These projects are necessary to maintain facilities in working order and in accordance with applicable codes. The risk of continuing to defer these projects is that the continued degradation of facilities could lead to potentially hazardous conditions that could impact equipment reliability and the safety of company personnel and the public. A review of the detailed candidate project list with a prioritized backlog of identified work provided the basis for the requested level of funding. While we have identified approximately $17.1 million of candidate work to be done in 2010 and beyond under this program (see attachment "DPS 43-406 Facility Improvement 2010 Candidate List.pdf"), we continue to see potential projects emerge via station inspections, engineering studies, and engineering service requests.

Question 2 – In 2008, actual expenditures for this program were $3.391 million vs. a budget of $6 million. This variance was due to later than anticipated construction starts for several projects including:

- Washington St. - Drainage improvement project
- Fresh Kills – Drainage improvement project
- Sedgwick Ave. – Office refurbishment

- Sprainbrook – Control room expansion
- E179th St., Parkchester, and Tremont – Lighting projects
- Webster Ave. PURS – Retaining wall refurbishment

In recognition of the increased volume of work under this program, a program manager and program engineer were assigned to assist in the coordination of the work and verify that program goals are met. Regular meetings between Engineering, Substations, and Construction groups are now held to track project deliverables. This increased oversight has resulted in more timely coordination between different project stakeholders. Approximately $1.8 million has been spent on this program year to date and a number of larger scale jobs are currently in progress. Based on our current progress and the expected completion of the in-progress jobs, spending for this program is expected to meet the 2009 budget. Please see attachment "DPS 43-406 Facility Improvement Upgrade July 2009 Update.pdf" for the status of the 2009 work.

By using a more formalized approach to tracking the deliverables for the work covered under this program, and by better communicating and coordinating the work planned to be done, we will be able to see that our spending goals for this program are met. As noted above, we have identified a substantial amount of work to be done in 2010 and beyond, and are working to meet all program deliverables . Attachment "DPS 43-406 Facility Improvement 2010 Candidate List.pdf" provides the schedule for a number of the key project milestones that we are working to track, in an effort to see that projects are completed as planned.

Question 3 – Please find the information requested in the attachment "DPS 43-406 Facility Improvement Upgrade July 2009 Update.pdf."

Redacted

YR	PN	LOCATION	DESCRIPTION	Cost (Est. or Approp.)	Scoping Document Date	Appropriation Date	PACKAGE REL. DATE	CONST. START DATE	CONST. COMP. DATE
2010	23113-08	Greenburg Service Ctr.	Upgrade Storm Water Drainage	450,000	8/30/2009	12/1/09	12/1/09	Spring 2010	Spring 2010
2010	11860-96	DUNWOODIE 345 KV (Mini-Bus)	INSTALL NEW PREFABRICATED BUILDING	369,000		Reapprop. 9/30/09	8/30/2008 - Comp.	3/1/10	5/30/10
2010	22660-07	Dunwoodie S/S	New Office Space in Gallery Area	2,181,481		12/19/09	12/19/09	TBD	TBD
2010	23048-08	Briarcliff WOL	Modify second floor for additional storage and office space	3,101,000	6/26/2009 (Comp)	10/15/09	10/15/09	TBD	TBD
2010	23129-08	E. 179TH ST	HVAC Upgrade	700,000	5/18/2009 (Comp)	12/15/09	12/15/09	TBD	TBD
2010	22393-07	W. 65th St. S/S	New HVAC	1,000,000	8/31/2009	4/2/10	3/25/10	TBD	TBD
2010	22580-07	W. 19th St. S/S	Heat Pump System/AC	800,000	2/9/2009 (Comp)	9/30/09	9/30/09	TBD	TBD
2010	20857-03	HELL GATE	REINFORCE DOCK FOR HEAVY LIFT	3,700,000		8/15/09	7/15/09	TBD	TBD
2010	22769-08	Various	Install Backflow Preventors on Water Supplies (40 Locations)	3,500,000		9/30/09	8/30/09	1/30/09	Multi-Year
2010	22080-06	World Trade Ctr.	WTC Transformer Vault #1 Exit	500,000	8/30/2009	8/1/09	9/1/09	Company Legal and Real Estate Involved.	Mike Corcoran to Schedule Mtg. w/ Landlord
2010	22467-07	Fresh Kills S/S	Install new sidewalk and curbing along exterior of station	392,000	(Comp)	9/30/09	9/30/09	TBD	TBD
2010		Vernon	Replace South Wall of Station	TBD					
2010		Parkchester	Raised Floor System Switchgear	400,000					

Totals	**17,093,481**
	Cost

Redacted

LOCATION	DESCRIPTION	Estimated Cost	YTD 2009 Expenditures	Total Exp. To Date (all years)	Remaining to be Spent	Projected EOY 2009 Exp.	CONST. START DATE	CONST. COMP. DATE	Comments
Various	Install metal enclosure on diesel generators	490,000	28,850	515,317		28,850		Complete	Carryover from 2008
Various	Control Room Standardization - Phase 2	2,000,000	(272,351)	1,932,902		(272,351)		Complete	Carryover from 2008
MILLWOOD	STABILIZATION OF SETTLING DISCONNECT SWITCH 1W1.	120,000			120,000	120,000	Nov. 2009	Nov. 2009	Outage window obtained.
Millwood S/S	Footing of Lightning Arrestor on Bus Sec 1W (C Phase) is leaning	400,000			400,000	400,000	Nov. 2009	Nov. 2009	Outage window obtained.
SPRAIN BROOK	EXPANSION OF CONTROL HOUSE	1,000,000	58,556	58,556	941,444	700,000	101/09	1/30/10	Awaiting DOB Permit
EAST 179TH ST	UPGRADE LIGHTING	322,000	5,519	268,178	53,822	50,000	9/1/09	TBD	Work in progress, expected to be completed in 2009.
HELL GATE	UPGRADE LIGHTING	305,000	42,901	208,976	96,024	130,000	9/1/09	TBD	Work in progress, expected to be completed in 2009.
SHERMAN CREEK	UPGRADE LIGHTING	345,000	18,806	179,898	165,102	150,000	9/1/09	TBD	Work in progress, expected to be completed in 2009.
North Queens	Install New Heating System	1,568,000	39,117	1,648,905	(80,905)	39,117		Complete	Carryover from 2008
Jamaica	Install Test Boxes/Conduit	120,000			120,000	120,000	8/31/09	9/30/09	Per area personnel, project to start in August.
Corona S/S	Install Test Boxes/Conduit	111,000			111,000	111,000	8/31/09	9/30/09	Per area personnel, project to start in August.
VARIOUS	INSTALL CONNECT BOXES (Diesel Connections)	800,000	642,149	691,754	108,246	750,000	10/1/08	10/1/09	
EAST 179TH ST	INSTALL BRIMAR SIGNS	115,000	(3,646)	118,967	(3,967)	(3,967)	In-Progress		Project believed to be complete, verifying with station personnel.
TREMONT	UPGRADE LIGHTING SYSTEM	101,000			101,000	50,000	9/1/09	TBD	Work in progress, expected to be completed in 2010.
PARKCHESTER	UPGRADE LIGHTING SYSTEM	202,000	27,324	119,581	82,419	100,000	9/1/09	TBD	Work in progress, expected to be completed in 2009.
EAST 13TH ST	FIBER OPTIC UPGRADE	306,000	78,080	291,874	14,126	92,000	In-Progress		Job Close To Completion
Leonard St.	Install new HVAC	429,000	61,941	359,403	69,597	62,000		Complete	Carryover from 2008
Sedgewick Ave.	Office Area Finish	382,000	14,234	38,064	343,936	358,170	TBD	TBD	Reappropiation required Start to be determined once complete.
Webster Ave. PURS	Modify retaining wall to improve drainage and removed damaged areas	352,000	29,107	34,943	317,057	350,000	9/15/09	11/15/09	Contractor working on scaffold plan.
147th St. PURS	Replace Walls	263,000	138,119	219,884	43,116	175,000	Complete	Complete	All Accts. Closed except Accts. Payable
E. 36th Street	Modify Exterior Walls	691,000	269,120	373,076	317,924	300,000	Complete	Complete	Complete
Water St.	Replace Fire Detection System	500,000	152,554	369,599	130,401	370,000	In-Progress	TBD	
E. 179TH ST	Replace Water Supply Meters	120,000	85,309	85,309	34,691	90,000		Complete	Complete
East 15th St.	Replace Gate and Install Driveway	233,000	86,867	156,531	76,469		In-Progress	TBD	Under review for transfer to Security.
Fresh Kills S/S	Install Sidewalk	392,000	11,103	11,103	380,897	11,103		12/31/10	Project on hold due to scope change
John St & Hudson	Install New Concrete Sidewalk (Adj to HAE S/S)	74,000			74,000	74,000	TBD	TBD	Start date being finalized with Construction
Fresh Kills S/S	Install adequate runoff solution to accommodate heavy rainfall in the 138 KV Yard.	750,000	6,018	6,018	743,982	750,000	8/21/09	12/31/09	PO Issued
Buchanan	Water Meter/Backflow Preventor	133,000	99,511	99,511	33,489	100,000		Complete	Complete
Jamaica	Swgr Floor Coating	265,000	5,796	5,796	259,204	265,000	In-Progress	11/1/09	
Washington St. S/S	Eliminate Storm Water Runoff from station onto adjorning property	193,000	117,444	117,444	75,556	192,000	8/1/09	10/1/09	Job In Progress 50% Comp.
E. 13th Street	Cooling of Relay Cabinet Enclosures	345,000	26,539	26,359	318,641	345,000	9/1/09	10/31/09	P.O. Issued Awaiting DOB Permit
SPRAIN BROOK	Cable Trough System	733,000	1,677	1,677	731,323	5,000	TBD	TBD	Project on hold, expected to resume in 2010
Plymouth St. S/S	Expand high volt. Test Room to accommodate a second high volt. Test set, or build a stand alone indoor facility to house the test set.	1,200,000			1,200,000	1,200,000	TBD	TBD	Start date being finalized with Construction
East River	UPGRADE LIGHTING	250,000	74,253	74,253	175,747	125,000	In-Progress	6/1/10	New Item
Leonard St.	UPGRADE LIGHTING	250,000	15,351	15,351	234,649	125,000	In-Progress	6/1/10	New Item
HELL GATE	Control Room HVAC	549,000			549,000	549,000	TBD	TBD	Start date being finalized with Construction
Ave. A S/S	New Steps at Sw House by Cap Banks	75,000			75,000	75,000	10/1/09	12/31/09	Work Being Done by M&C Shops (Kevin Sweeney)

Totals	**16,484,000**	**1,860,248**	**8,029,229**	**8,412,990**	**8,085,922**
	Cost	**YTD**	**TTD**	**Remaining**	

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS43
Date of Response: 08/19/2009
Responding Witness: IIP

Question No. :410
Subject: Electric Operations – System and Component Performance – Shunt Reactor Program - 1. Describe in detail the rationale for increasing the 2010 through 2012 forecasted budgets versus the Company's approved budget in 2009? 2. In reviewing the Company's spending in 2008, it appears that the Company was not able to achieve its Shunt Reactor Program budget goal. Explain how Con Edison expects to meet the more aggressive goal of spending $2.62 million more in each of the three rate years?

Response:

1. **Describe in detail the rationale for increasing the 2010 through 2012 forecasted budgets versus the Company's approved budget in 2009?**
   The 2009 approved budget for B/Q is $1.3M for the Reactor Program. The forecasted budget for 2010-12 is $2.7M per year. The increase in work associated with the Reactor program is necessary to address the current backlog and is made possible due to the steady reduction in transformer relief work. Shunt Reactors provide compensation to 27 KV network feeders in the Brooklyn/Queens region to reduce the over voltage that may be seen in the secondary network during a back feed condition. A 27kv network feeder that is not properly compensated with a shunt reactor has the potential to cause over voltages on the secondary system during a back feed condition. This program will reduce the risk of these over voltages that have the potential to do damage to company and customer equipment.

2. **In reviewing the Company's spending in 2008, it appears that the Company was not able to achieve its Shunt Reactor Program budget goal. Explain how Con Edison expects to meet the more aggressive goal of spending $2.62 million more in each of the three rate years?**
   In 2008, B/Q had a $40.65M transformer relief program. The work associated with this program and the Reactor program required the use of same contractors and Company forces to complete. With the reduction in work in the transformer relief program, there is adequate contractor and company forces to complete the vaults and install the cable associated with the Reactor program.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS43
Date of Response: 08/21/2009
Responding Witness: IIP

Question No. :411
Subject: Electric Operations – System and Component Performance – Aerial (Okonite) Cable Replacement Program - 1. Explain the reasons(s) for the variations, delays, or changes in actual spending versus the budget for the years 2005 and 2007. 2. Describe in detail the rationale for increasing the 2009 through 2012 forecasted budgets versus the actual spending in 2008? 3. Provide the number of Aerial Okonite cables the Company plans to replace in each of the years 2010, 2011 and 2012.

Response:

1. Explain the reasons(s) for the variations, delays, or changes in actual spending versus the budget for the years 2005 and 2007.

The reason for the variation in actual spending for this program was to maintain the overall System Reinforcement budget at its approved funding level. The budget variation for the years 2005 and 2007 was primarily due to a shift in funding to various system reinforcement projects with a higher priority whose expenditures greatly exceeded their original estimates. Both 2005 and 2007 had major substation load transfer projects which used significant portions of our resources. In 2005, major load transfers were done at Bruckner and White Plains Substations while 2007 saw the new Mott Haven substation established and work started on the new Rockview Substation

In 2006 and 2008, expenditures exceeded budget. In 2006, expenditures were $823,000 and the budget was $0. In 2008, expenditures were $539,000, and the budget was $501,000.

2. Describe in detail the rationale for increasing the 2009 through 2012 forecasted budgets versus the actual spending in 2008?

In 2008, the Company's expenditure of $539,000 exceeded its budget of $501,000. Nonetheless, the expenditure of only $500,000 is not adequate given the deterioration experienced with this feeder cable. The increase funding for this program beginning in 2009 and continuing in the rate years reflects the Company's recognition that the failure to replace this old and deteriorating aerial cable on the system proactively and systematically over time will lead to more lengthy outages and inconveniences to our customers and degradation of the Company's non-network CAIDI index. The loss of a primary feeder in a first contingency load area during a high load period, when accompanied by another feeder loss, can interrupt service to customers.

The Company expects to conduct fewer large system re-enforcement and load relief projects expected in 2010, 2011 and 2012, and this has a two fold effect. Firstly, it frees up more Company resources to be available for the reliability programs such as the Aerial (Okonite) Cable Replacement Program. Secondly, the load relief programs in recent years, by their very nature also replaced old and poor performing cable that was also projected to be overloaded. Without an increase in the reliability spending to compensate for the drop in load relief work, the net reliability work on the system will decline.

At the end of August 2009 we anticipate having spent a total of $1,160,200 against this program, and we expect to spend the full $3 million budget in 2009.

3. Provide the number of Aerial Okonite cables the Company plans to replace in each of the years 2010, 2011 and 2012.

Our plan is to replace approximately 215 spans of Okonite Aerial Cable per year. By the end of August 2009, we will have replaced 95 sections.

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS43
Date of Response: 08/20/2009
Responding Witness: IIP

Question No. :415
Subject: Follow-up to DPS-29 - 1. For each Electric System, Transmission, and Substation project and program listed in Exhibit IIP-9, provide the corresponding rank and project score received after prioritization. 2. For each Electric Distribution System project listed in Exhibit IIP-9, identify the project as reinforcement or reliability, and provide each project's rank in prioritization. 3. Assuming the Company was provided rate recovery for only $1 billion of T&D expenditures annually for the years 2010-2012, for the T&D projects contained in IIP-9 for the years 2010-2012: a. Provide the resulting level of spending for each project. b. For each project that has a reduced funding level, provide the possible ramifications, if any, associated with the reduced funding level.

Response:
Q1. For each Electric System, Transmission, and Substation project and program listed in Exhibit IIP-9, provide the corresponding rank and project score received after prioritization.

Response

See attached IIP projects and programs listed with corresponding rank and project prioritization score as ranked at the time of our May 2009 filing for SSO, SO and TO. Also see attached IIP projects and programs listed with corresponding rank and project prioritization score as ranked at the time of our May 2009 filing for EDS, including a project list identified as reinforcement or reliability.

Q2. For each Electric Distribution System project listed in Exhibit IIP-9, identify the project as reinforcement or reliability, and provide each project's rank in prioritization.

Response

See second attachment to part 1.

Q3. Assuming the Company was provided rate recovery for only $1 billion of T&D expenditures annually for the years 2010-2012, for the T&D projects contained in IIP-9 for the years 2010-2012:

a) **Provide the resulting level of spending for each project.**

b) **For each project that has a reduced funding level, provide the possible ramifications, if any, associated with the reduced funding level.**

Response

The response to part 3 is forthcoming.

Redacted

Company Name: Con Edison
Case Description: 2009 Electric Rate Filing
Case: 09-E-0428

Response to DPS Interrogatories – Set DPS43
Date of Response: 08/19/2009
Responding Witness:

Question No. :416
Subject: Projects approved in Case 09-E-0310 - In Case 09-E-0310 (fn-Case cite), the Commission approved several Con Edison projects (see Appendix C of July 27 Order). For each Con Edison project approved in the July 27 Order identify: 1) whether the Commission has previously approved funding for the project (or parts of the project) and if so, provide specific details regarding what was funded and funding levels and actual expenditures by year. 2) whether the Company is seeking funding in this proceeding for the project (or parts of the project) and if so, provide specific details regarding what was is being requested, including funding levels by year. 3) The funding approved in Case 09-E-0310 is for new and/or incremental work. For any project approved in Case 09-E-0310, please describe how that work is incremental in nature and not a duplication of the funding being sought in this proceeding.

Response:
In Case 09-E-0310 (fn-Case cite), the Commission approved several Con Edison projects (see Appendix C of July 27 Order). For each Con Edison project approved in the July 27 Order identify:

1) Whether the Commission has previously approved funding for the project (or parts of the project) and if so, provide specific details regarding what was funded and funding levels and actual expenditures by year.

Indicated in the table below are the names of projects included in both the rate filing and the Stimulus filing. Please note that the scope of work for these projects as set forth in the Stimulus filing is for work that is incremental to the work proposed for these projects in the rate filing.

	2006		2007		2008		2009 approved
Previously Approved Funding	**Budgeted**	**Actual**	**Budgeted**	**Actual**	**Budgeted**	**Actual**	
Secondary Visualization Model	$ -	$ -	$ -	$ -	$ 2,900	$ 2,938	$ 4,250
Model Validation	$ 4,000	$ 7,413	$ -	$ -	$ 2,000	$ -	$ 2,000
UG Sectionalizing Switches	$ 721	$ 2,077	$ 1,297	$ 2,057	$ 3,210	$ 1,622	$ 4,062
Overhead Feeder Sectionalizing	$ 196	$ 1,906	$ 1,368	$ 485	$ 2,305	$ 3,090	$ 2,631
RMS Data Acquisition System	$ 11,959	$15,503	$ 23,723	$15,099	$ 17,852	$15,275	$ 1,000
Pressure, Temperature & Oil Sensors	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,559
High Tension Monitoring and Data Acquisition System	$ -	$ -	$ -	$ -	$ -	$ -	$ 730

2) Whether the Company is seeking funding in this proceeding for the project (or parts of the project) and if so, provide specific details regarding what was is being requested, including funding levels by year.

Project Name as show in Rate Filing	Funding 2010 (000's)	Exhibit	Page No.
Secondary Visualization Model	$2,553	IIP-7	75
Model Validation	$2,000	IIP-7	78
UG Sectionalizing Switches	$4,356	IIP- 4	145
Overhead Feeder Sectionalizing	$3,189	IIP- 4	182
Transformer Remote Monitoring System 3rd Generation Transmitter	$7,850	IIP- 4	143
Pressure, Temperature, & Oil Sensors	$3,559	IIP- 5	31
High Tension Monitoring Data Acquisition System	$730	IIP- 7	69

3) The funding approved in Case 09-E-0310 is for new and/or incremental work. For any project approved in Case 09-E-0310, please describe how that work is incremental in nature and not a duplication of the funding being sought in this proceeding.

Please note that the scope of work for these projects as set forth in the Stimulus filing is for work that is incremental to the work proposed for these projects in the rate filing.

Project Name as show in Rate Filing	Scope of Work in Rate Filing 2010	Scope of Work in Stimulus Filing 2010-2012	Total
Secondary Visualization Model	11 models	14 models	25 models
Model Validation	500 devices	1,675 devices	2175 devices
UG Sectionalizing Switches	27 switches	100 switches	127 switches
Overhead Feeder Sectionalizing	97 switches	750 switches	847 switches
Transformer Remote Monitoring System 3rd Generation Transmitter	3,380 units	4,952 units	8332 units
Pressure, Temperature, & Oil Sensors	3,050 sensors	7,392 sensors	10,442 sensors
High Tension Monitoring Data Acquisition System	386 locations	700 locations	1086 locations

STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 Transmission and Distribution Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

	2010			2011		
CATEGORY	**Con Ed**	**Staff**	**Adjustment**	**Con Ed**	**Staff**	**Adjustment**
Transmission	182,605	171,605	11,000	98,485	96,185	2,300
System	9,350	6,850	2,500	3,250	3,250	-
Substation	302,935	254,649	48,286	260,240	216,954	43,286
Electric	904,993	806,487	98,506	890,307	801,702	88,605
Total T&D Capital Budget	**$ 1,399,883**	**$ 1,239,591**	**$ 160,292**	**$ 1,252,282**	**$ 1,118,091**	**$ 134,191**

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STAFF INFRASTRUCTURE INVESTMENT PANEL

2010 - 2011 Transmission Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	Con Ed	Staff	Adjustment	Con Ed	Staff	Adjustment	(Y)
INCREASED CUSTOMER DEMAND									
Dynamic Feeder Rating	2,415	2,415	1,000	1,000	-	1,000	1,000	-	
Reconductor Feeders 45 and 46			-	-	-		-	-	
Vernon - W49th St-38M72 Upgrade	11,500	11,500	19,500	19,500	-	7,000	7,000	-	
179th St-Reinforcement - M29 (Includes Academy)	160,000	160,000	135,000	135,000	-	55,000	55,000	-	
Sub-Total	**$ 173,915**	**$ 173,915**	**$ 155,500**	**$ 155,500**	**$ -**	**$ 63,000**	**$ 63,000**	**$ -**	
SYSTEM AND COMPONENT PERFORMANCE									
Feeder 34182/4	-	-	-	$ -	$ -	-	-	-	
Manhattan-Replace 69kV Feeders On QBB	-	-	-	$ -	$ -	-	-	-	
Millwood-Replace Wood Poles W/Steel Poles	100	100							
Sprain Brook - W 49th St-Feeder M51	-	-	3,000	$ -	$ 3,000	-	3,000	(3,000)	Y
Staten Island-Feeders 38R51 And 38R52	-	-	-	$ -	$ -	4,210	4,210	-	
Cable System Enhancement - Pothead Alarms	1,100	1,100							
Emergent Transmission Reliability	10,000	4,000	10,000	4,000	6,000	10,000	6,200	3,800	Y
Re-Conductor Dunwoodie – Sprain Brook Transmission Corridor	-	-	500	-	500	5,400	5,400	-	Y
Reinforce Hudson River Crossing Towers	3,000	3,000	1,800	1,800	-	1,800	1,800	-	
Replace 69M43/69M44 With 38M53 & 38M54	3,000	3,000							
Replace Feeder 69M41 & 69M45	-	-	1,000	1,000	-	5,000	5,000	-	
Replacement of Feeders 18001 & 18002	4,000	4,000	2,180	2,180	-	-	-	-	
Transmission Feeder Failures	5,000	5,000	5,000	3,500	1,500	5,000	3,500	1,500	
Upgrade Overhead 345kV Transmission Structures	2,100	2,100	2,200	2,200	-	2,300	2,300	-	
Replace potheads on Feeder 34184 (Astoria/Corona)	-	-							
Phasor Measuring Units for SCADA Real Time Operation	150	150	250	250	-	200	200	-	
Sub-Total	**$ 28,450**	**$ 22,450**	**$ 25,930**	**$ 14,930**	**$ 11,000**	**$ 33,910**	**$ 31,610**	**$ 2,300**	
ENVIRONMENTAL									
DEC Program Line	1,225	1,225	775	775	-	775	775	-	
Environmental Enhancements	-	-	400	400	-	800	800	-	
Sub-Total	**$ 1,225**	**$ 1,225**	**$ 1,175**	**$ 1,175**	**$ -**	**$ 1,575**	**$ 1,575**	**$ -**	
TOTAL TRANSMISSION OPERATIONS	**$ 203,590**	**$ 197,590**	**$ 182,605**	**$ 171,605**	**$ 11,000**	**$ 98,485**	**$ 96,185**	**$ 2,300**	

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STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 System Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	**2009 Original Filing - May**	**2009 Revised**	**Con Ed**	**Staff**	**Adjustment**	**Con Ed**	**Staff**	**Adjustment**	**(Y)**
STRATEGIC IT ENHANCEMENTS									
Bulk Power Improvements									
SOCCS Visualization	500	500	500	500	-				
District Operations Improvement									
System Operation Enhancements	250	250	400	400	-	300	300	-	
District Operator Task Managing System	250	250	400	400	-	250	250	-	
Operation Management System Enhancements	500	500	1,000	1,000	-	400	400	-	
EMS-Continuance									
EMS Reliability AECC and ECC	-	-	500	-	500	1,000	1,000	-	Y
Work Management Systems								-	
Distribution Orders Enhancements	250	250	250	250	-	300	300	-	
Outage Scheduling System	3,000	1,000	3,000	1,000	2,000				Y
Facilities / Utilities Improvement									
ECC/AECC Facility Security Enhancements	300	300	300	300	-				
Computer Room Renovation						500	500	-	
ECC UPS Battery Replacement									
Training Area Expansion	750	750	750	750	-				
Add Diesel Generator	1,900	1,900							
East Control Room Renovations	3,000	3,000							
Operator Console Replacement	1,000	1,600							
HVAC Upgrade - East Computer Room	500	500							
Command and Control Programs	250	-							
Operations Requirements									
Interface with NYISO	100	100	100	100	-	100	100	-	
Plant Information System	-	-	300	300	-				
Cyber Security	200	200	300	300	-	200	200	-	
Operations Network for EMS	300	100	250	250	-	200	200	-	
Control Center Phone System Replacement			1,300	1,300	-				
Facilities / Utilities Improvement	400	400							
GT Remote Start System	600	600							
New EMS									
Replacement Program SOCCS-X Energy Management System	2,000	2,000							
Sub-Total	**16,050**	**14,200**	**9,350**	**6,850**	**2,500**	**3,250**	**3,250**	**-**	
TOTAL SYSTEM OPERATION	**$ 16,050**	**$ 14,200**	**$ 9,350**	**$ 6,850**	**$ 2,500**	**$ 3,250**	**$ 3,250**	**$ -**	

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STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 Substation Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	Con Ed	Staff	Adjustment	Con Ed	Staff	Adjustment	(Y)
INCREASED CUSTOMER DEMAND									
Astor- Establish New Station	3,000	3,000							
Emergent Load Relief Program	1,300	1,300	1,300	1,300	-	1,300	1,300	-	
Newtown-Establish Station	92,780	92,780	42,000	42,000	-	-	-	-	
Parkchester-Install 3rd Cap Bank						1,000	1,000	-	
Parkchester-Install 4th Transformer						3,000	3,000	-	
Transformer Cooling Program	1,000	1,000							
Woodrow-Install Third Transformer And Fresh Kills Expand 138kV Station	25,000	25,000	12,185	12,185	-				
York-Establish New Area Substation	40,000	40,000	2,500	2,500	-	20,000	20,000	-	
GENERATION INTERCONNECTION*									
Astoria East-Install Phase Angle Regulator	3,000	-	20,000	-	20,000	13,000	-	13,000	
Corona-Install Series Reactor	2,000	-	15,000	-	15,000	11,000	-	11,000	
Sub-Total	**$ 168,080**	**$ 163,080**	**$ 92,985**	**$ 57,985**	**$ 35,000**	**$ 49,300**	**$ 25,300**	**$ 24,000**	
SYSTEM AND COMPONENT PERFORMANCE									
EQUIPMENT									
138kV Circuit Breaker Program Upgrade Program	11,700	11,700	11,700	11,700	-	11,700	11,700	-	
345kV Circuit Breaker Upgrade Program	5,000	5,000	5,000	5,000	-	5,000	5,000	-	Y
Circuit Switcher Replacement Program	500	500	500	500	-	500	500	-	
Condition Based Monitoring Equipment	250	250	250	250	-	250	250	-	
Corona - Breaker Addition (6S and 8X)	3,000	3,000	2,650	2,650	-				
Bus Section Upgrade - E. 63rd Street	-	-							Y
Elmsford-Upgrade of Elmsford - Substation	25,000	25,000	32,000	32,000	-	27,740	27,740	-	
Failed Equipment Other Than Transformers	1,500	1,500	1,500	1,500	-	1,500	1,500	-	
Failed Transformer Program	30,046	30,046	25,800	25,800	-	24,700	24,700	-	
Rainey-Replace Temp Transformer With Permanent	4,000	4,000							
Replace Disconnect Switches	4,600	4,600	4,600	4,600	-	4,800	4,800	-	
Replace Overdutied 13/27kV Circuit Breaker Programs	10,800	10,800	10,800	10,800	-	10,800	10,800	-	
Transformer Replacement Programs	13,000	13,000	20,500	20,500	-	20,000	20,000		
Sub-Total	**$ 109,396**	**$ 109,396**	**$ 115,300**	**$ 115,300**	**$ -**	**$ 106,990**	**$ 106,990**	**$ -**	
RELAY									
Control Cable Upgrade Program	1,000	1,000	1,000	1,000	-	1,000	1,000	-	
Relay Modifications	5,500	5,500	5,500	5,500	-	5,500	5,500	-	
Upgrade Analog Circuits To Digital Fiber	2,000	2,000	2,000	2,000	-	1,800	1,800	-	
Relay Protection System Redundancy (Single Point of Failure)	-	-	2,000	-	2,000	8,000	-	8,000	
Sub-Total	**$ 8,500**	**$ 8,500**	**$ 10,500**	**$ 8,500**	**$ 2,000**	**$ 16,300**	**$ 8,300**	**$ 8,000**	

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STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 Substation Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	Con Ed	Staff	Adjustment	Con Ed	Staff	Adjustment	(Y)
MISCELLANEOUS COMPONENTS									
Additional G&T Devices	500	500	500	500	-	500	500	-	Y
Area Substation Reliability And Auto Ground Circuit Switchers	10,500	10,500	10,500	6,493	4,007	10,500	6,493	4,007	
Capacitor Cable Upgrade Program	3,000	3,000	3,000	3,000	-	3,000	3,000	-	
Category Alarms	2,250	2,250	2,250	2,250	-	2,250	2,250	-	
Construct Relay Enclosure Houses	1,500	1,500	1,500	1,500	-	1,500	1,500	-	
Corona Settlement	1,000	1,000	1,000	1,000	-		-	-	
DC System Upgrade Program	3,500	3,500	3,500	3,500	-	3,500	3,500	-	
Diesels / Black start Restoration (Phase 2) - Upgrade Station L & P	1,200	1,000	1,000	1,000	-	1,000	1,000	-	Y
E. 13th Street - Alarm Panel Replacement and Control Systems	-	-				1,500	1,500	-	
E179th Street-Substation - Bus Section Upgrade Program	-	-	6,000	6,000	-	15,000	15,000	-	
East River-Protection System Upgrade	3,500	3,500	3,500	3,500	-	3,100	3,100	-	
Facility Improvement Program	6,000	6,000	6,000	3,721	2,279	6,000	3,721	2,279	
Fire Suppression System Upgrades	-	-	6,000	6,000	-	6,000	6,000	-	
High Voltage Test Sets	3,500	3,500	5,000	5,000	-	3,000	3,000	-	
New Maximo Upgrade	400	400							
Rapid Restore Enhancements- Expansion of TOMS	200	200	200	200	-	-	-	-	
Reinforced Ground Grid	500	500	700	700	-	700	700	-	
Revenue Metering Upgrade	500	500	500	500	-	500	500	-	
Roof Replacement Program	3,000	3,000	3,000	3,000	-	2,100	2,100	-	
Small Capital Equipment Program	3,000	3,000	3,000	3,000	-	3,000	3,000	-	
Substation Loss Contingency	2,000	1,000	2,000	1,000	1,000	2,000	1,000	1,000	Y
Switchgear Enclosure Upgrade Program	500	500	500	500	-	500	500	-	
White Plains-Substation - Bus Section Upgrade Program	550	550							
Sub-Total	**$ 47,100**	**$ 45,900**	**$ 59,650**	**$ 52,364**	**$ 7,286**	**$ 65,650**	**$ 58,364**	**$ 7,286**	
ENVIRONMENTAL									
Environmental Risk Mitigation	3,500	3,500	3,500	3,500	-	3,500	3,500	-	
Pumping Plant Improvement	8,500	5,500	8,500	5,500	3,000	8,500	5,500	3,000	Y
PURS Supervisory Control & Data Acquisition	3,000	3,000	3,000	3,000	-	3,000	3,000	-	
Sub-Total	**$ 15,000**	**$ 12,000**	**$ 15,000**	**$ 12,000**	**$ 3,000**	**$ 15,000**	**$ 12,000**	**$ 3,000**	
PUBLIC AND EMPLOYEE SAFETY									
Security Enhancements	4,100	3,100	4,000	4,000	-	4,000	4,000	-	Y
Sub-Total	**$ 4,100**	**$ 3,100**	**$ 4,000**	**$ 4,000**	**$ -**	**$ 4,000**	**$ 4,000**	**$ -**	
STRATEGIC IT ENHANCEMENTS									
SOCCS - RTU Replacement	3,000	3,000	3,000	3,000	-	500	500	-	
Substation Automation Target Information System	2,000	1,000	2,000	1,000	1,000	2,000	1,000	1,000	Y
Technology Improvements	705	705	500	500	-	500	500	-	
Sub-Total	**$ 5,705**	**$ 4,705**	**$ 5,500**	**$ 4,500**	**$ 1,000**	**$ 3,000**	**$ 2,000**	**$ 1,000**	
TOTAL SUBSTATION OPERATIONS	**$ 357,881**	**$ 346,681**	**$ 302,935**	**$ 254,649**	**$ 48,286**	**$ 260,240**	**$ 216,954**	**$ 43,286**	

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STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 Electric Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	**2009 Original Filing - May**	**2009 Revised**	**Con Ed**	**Staff**	**Adjustment**	**Con Ed**	**Staff**	**Adjustment**	**(Y)**
Increased Customer Demand									
New Business									
New Business Capital	157,000	157,000	123,000	123,000	-	122,000	122,000	-	
Meter Installation	17,721	17,721	17,771	17,771	-	18,071	18,071	-	
Sub-Total	**$ 174,721**	**$ 174,721**	**$ 140,771**	**$ 140,771**	**$ -**	**$ 140,071**	**$ 140,071**	**$ -**	
System Reinforcement Area SS Load Relief									
Newtown	14,000	14,000	4,000	4,000	-	-	-	-	
Astor (Herald Sq. Transfer)	3,000	3,000							
Penn/Waterside	3,000	3,000	4,600	4,600	-	900	900	-	
Randall's Island	2,497	2,497							
City Hall to Cortlandt	1,100	1,100	200	200	-	-	-	-	
York to Lenox Hill	-	-	-	-	-	-	-	-	
Chelsea W 19th St. to Murray Hill	$ -	$ -	$ -	-	-	$ 3,700	3,700	-	
Sub-Total	**$ 23,597**	**$ 23,597**	**$ 8,800**	**$ 8,800**	**$ -**	**$ 4,600**	**$ 4,600**	**$ -**	
Base Growth / Relief									
Primary Feeder Relief	34,289	34,289	33,583	33,583	-	32,525	32,525	-	
Network Load Relief Transformer Installations	50,860	47,860	45,620	45,620	-	46,158	46,158	-	Y
NonNetwork Fdr Relief (Open Wire)	9,820	9,820	8,605	8,605	-	9,125	9,125	-	
Overhead Transformer Relief	2,191	2,191	2,642	2,642	-	2,642	2,642	-	
Sub-Total	**$ 97,160**	**$ 94,160**	**$ 90,450**	**$ 90,450**	**$ -**	**$ 90,450**	**$ 90,450**	**$ -**	
Distribution Substation									
Distribution Substation Load Relief	-	-							
Spill Prevention Control Counter Measures		-							
Sub-Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
Meter Purchase	12,349	12,349	9,802	9,802	-	10,036	10,036	-	
System and Component Performance									
Enhanced Reliability									
Elmsford Refurbishment	-	-	-	-	-	1,300	1,300	-	
59th Street Bridge Crossing	-	-	-	-	-	-	-	-	
(Primary) Cable Crossings	6,500	6,500	8,000	8,000	-	8,000	8,000	-	
HiPot	3,400	3,400	5,498	3,400	2,098	5,600	3,400	2,200	Y
PILC	32,035	27,085	33,000	27,085	5,915	33,000	27,085	5,915	Y
Transformer Remote Monitoring System 3rd Generation Transmitter	8,400	8,400	7,850	7,850	-	7,500	7,500	-	
Sectionalizing Switches	4,062	3,562	4,356	3,562	794	4,475	3,562	913	Y
Underground Secondary Reliability Program	40,374	24,274	37,422	24,274	13,148	40,866	24,274	16,592	Y
Secondary Open Mains	147,331	147,331	139,245	120,000	19,245	129,871	120,000	9,871	
Grounding Transformers	150	150	550	550	-	520	520	-	
Shunt Reactors	1,367	1,367	2,761	1,051	1,710	2,788	1,051	1,737	
Network Reliability	16,300	11,900	25,723	21,323	4,400	26,545	22,145	4,400	Y
Coastal Storm Risk Mitigation	2,446	446	3,000	1,000	2,000	3,000	1,000	2,000	Y
Transformer Purchase	148,152	134,152	144,606	130,606	14,000	138,640	124,640	14,000	Y
Sub-Total	**$ 410,517**	**$ 368,567**	**$ 412,011**	**$ 348,701**	**$ 63,310**	**$ 402,105**	**$ 344,477**	**$ 57,628**	
Distribution Substation Modernization									
Tap Changer Position Indicator System	81	81	132	132	-	-	-	-	
Temperature Gauges	150	150	100	100	-	100	100	-	
USS Transformer Replacement	370	370	600	600	-	600	600	-	
4kV USS Switchgear Replacement	2,200	2,200	2,200	2,200	-	1,200	1,200	-	
USS Life Extension Program	1,769	1,769	1,170	1,170	-	1,361	1,361	-	
Auto Reclose On Bank Breakers	154	154	250	250	-	250	250	-	
Facility Improvement	-	-							
Breaker Replacement	-	-							
Sub-Total	**$ 4,724**	**$ 4,724**	**$ 4,452**	**$ 4,452**	**$ -**	**$ 3,511**	**$ 3,511**	**$ -**	
Overhead Enhancement									
C Truss Program	1,746	746	2,058	1,752	306	2,058	1,752	306	Y
Autoloop Reliability	6,095	3,100	7,359	3,100	4,259	7,528	3,100	4,428	Y
Aerial (Okonite) Cable Replacement	3,021	3,021	2,532	1,009	1,523	2,544	1,009	1,535	
#4,#6 Self Supporting Wire	3,165	3,165	3,169	3,169	-	3,175	3,175	-	
Overhead Feeder Sectionalizing Program	2,631	2,331	3,189	2,331	858	3,202	2,331	871	Y
Automated Emergency Ties	-	-	750	750	-	750	750	-	
Overhead Feeder Reliability	752	752	750	750	-	1,125	1,125	-	
Rear-Lot Pole Elimination	1,437	437	1,437	437	1,000	1,437	437	1,000	Y
Enhanced 4kV Grid Monitoring	2,645	2,645							Y
4kV UG Reliability	475	475	1,111	1,111	-	1,111	1,111	-	
Overhead Conductor Clearance	-	-	1,630	1,630	-	1,622	1,622	-	
Overhead Secondary Reliability Program	500	500	500	500	-	500	500	-	
Targeted Primary DBC Replacement	504	-	800	-	800	800	-	800	Y
URD Cable Rejuvenation/Fault Indicator	806	806	806	806	-	198	198	-	
ATS Installation USS Reliability XW	2,450	1,450	2,450	1,450	1,000	2,450	1,450	1,000	Y
Sub-Total	**$ 26,227**	**$ 19,428**	**$ 28,541**	**$ 18,795**	**$ 9,746**	**$ 28,500**	**$ 18,560**	**$ 9,940**	
Emergency Response									
Emergency Primary Cable Replacement	59,625	59,625	56,056	56,056	-	53,856	53,856	-	
Overhead	15,992	15,992	14,267	14,267	-	14,267	14,267	-	
Emergency Service Replacement	19,743	19,743	20,053	20,053	-	20,053	20,053	-	
Street Lights	18,606	18,606	15,003	15,003	-	14,753	14,753	-	
Transformer Installation	24,557	24,557	21,146	21,146	-	21,146	21,146	-	
Sub-Total	**$ 138,523**	**$ 138,523**	**$ 126,525**	**$ 126,525**	**$ -**	**$ 124,075**	**$ 124,075**	**$ -**	
Public Safety									
Vented Manhole Cover	10,000	6,800							Y
Vented Service Box Covers	8,375	6,000	15,375	11,875	3,500	15,375	15,375	-	Y
Isolation Transformers	5,809	4,809	5,809	5,809	-	10,482	8,145	2,337	Y
Pressure, Temperature, and Oil Sensors	3,559	3,559	3,559	3,559	-	3,559	3,559	-	
Sub-Total	**$ 27,743**	**$ 21,168**	**$ 24,743**	**$ 21,243**	**$ 3,500**	**$ 29,416**	**$ 27,079**	**$ 2,337**	
Environmental									
Oil Minders	500	500	600	600	-	600	600	-	
Sub-Total	**$ 500**	**$ 500**	**$ 600**	**$ 600**	**$ -**	**$ 600**	**$ 600**	**$ -**	

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STAFF INFRASTRUCTURE INVESTMENT PANEL
2010 - 2011 Electric Operations Capital Budget Adjustments
For Consolidated Edison Electric Rate Case 09-E-0428
Budget ($000)

			2010			2011			Revision Indicator
DESCRIPTION	2009 Original Filing - May	2009 Revised	Con Ed	Staff	Adjustment	Con Ed	Staff	Adjustment	(Y)
Strategic IT Enhancements									
Outage Management System	4,600	4,600	2,300	2,300	-	2,300	2,300	-	
Meter Shop ADAMS	750	-	2,750	-	2,750	1,000	-	1,000	Y
4kV Load Shedding System	450	-	-	-	-	-	-	-	Y
ATS Automation	150	150	100	100	-	100	100	-	
Energy Services Case Management	-	-	3,000	3,000	-	6,000	6,000	-	
Power Quality (PQNodes) System Upgrade	1,650	1,650	1,650	1,650	-	1,145	1,145	-	
SCADA Systems Consolidation	800	800	950	950	-	600	600	-	
Electric Distribution Control Center Upgrades	3,000	500	3,000	500	2,500	3,000	500	2,500	Y
Mapping System Upgrades	2,900	500	2,000	500	1,500	2,000	500	1,500	Y
Distribution Engineering Workstation	500	-	500	-	500	500	-	500	Y
Grid Optimization	500	-							Y
Integrated System Model	1,750	1,750	1,750	1,750	-	1,500	1,500	-	
Decision Aids	500	500	500	500	-	500	500	-	
High Tension Monitoring Data Acquisition System	730	730	730	730	-	730	730	-	
RMS Data Acquisition System	1,000	1,000	1,500	1,500	-	1,500	1,500	-	
Heads Up Display	500	500	1,000	1,000	-	1,000	1,000	-	
Secondary Visualization Model	4,250	4,250	2,553	2,553	-	2,553	2,553	-	
Model Validation	2,000	2,000	2,000	2,000	-	2,000	2,000	-	
Joint Use Pole Life Cycle Management System	1,848	1,848	2,315	2,315	-	2,315	2,315	-	
Sub-Total	**$ 27,878**	**$ 20,778**	**$ 28,598**	**$ 21,348**	**$ 7,250**	**$ 28,743**	**$ 23,243**	**$ 5,500**	
Efficiency and Process Improvement									
Work Management Systems	5,000	5,000	29,700	15,000	14,700	28,200	15,000	13,200	Y
Accounting by Network	300	300							
Sub-Total	**$ 5,300**	**$ 5,300**	**$ 29,700**	**$ 15,000**	**$ 14,700**	**$ 28,200**	**$ 15,000**	**$ 13,200**	
TOTAL ELECTRIC OPERATIONS	**$ 949,239**	**$ 883,815**	**$ 904,993**	**$ 806,487**	**$ 98,506**	**$ 890,307**	**$ 801,702**	**$ 88,605**	