Electricity Supply Infrastructure Improvements

Final Technical Status Report December 2010

Daniel Piekarski and Dana Brad
Northern Indiana Public Service Company
Merrillville, Indiana

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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NREL/SR-5500-49793
February 2011

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1 Transmission Project Introduction

Electricity infrastructure across the country is aging rapidly. This has led to electrical transmission problems and reliability issues. Upgrading electro-mechanical protection and control with microprocessor based equipment enables the electric transmission grid to operate within more precise limitations, increasing transmission capacity and improving the overall performance of the grid. Modernization is critical to prevent future transmission problems such as those that occurred across the Midwest on August 14, 2003.

The 345KV transmission circuits are the critical backbone of the electric grid in the Midwest. Most of Northern Indiana Public Service Company's (NIPSCO) 345 kV Transmission circuits were installed in the 1970's with state of the art protective relaying existing at that time. By performing regular periodic relay maintenance (inspection, calibration, and functional testing), and by monitoring and promptly addressing performance issues with these protection schemes, the reliability and security of the NIPSCO electrical system has been maintained over the past thirty-five years. However, the protective relays used in many of these schemes are nearing the end of their life cycle. Furthermore, improvements in technology and the advent of the microprocessor make it possible to improve the protection, and greatly enhance the monitoring and post fault analysis tools used in system protection. The use of these technologies results in greater dependability, security, selectivity, and speed of the protection schemes. The cumulative effect produces improvements in the overall reliability of the electrical transmission and distribution system.

There are two distinct aspects of the transmission portion of this project: The first aspect relates to the modernization of the protection and control schemes of two 345KV circuits on the NIPSCO system. The second entails the installation of monitoring equipment on transmission transformers.

1.1 Protection and Control-Modernization of the 345KV Transmission System

The first aspect relates to the modernization of the protection and control schemes of two 345KV circuits on the NIPSCO system. One circuit between St. John and Green Acres Substations, and a second circuit between Babcock and Lake George Substations.

The protection schemes on these circuits are being upgraded from primarily solid state and electromechanical equipment to new microprocessor based equipment. This new microprocessor based equipment has proven to provide the reliability and performance that is necessary to protect and control today's modern electrical transmission system.

345 KV lines are protected using redundant, multi level relaying schemes we refer to as System 1 and System 2. System 1 is typically a four zone distance relaying scheme which incorporates permissive overreaching transfer trip or a similar communication based scheme. System 2 is typically a current only communication based scheme such as current differential or phase comparison. In addition, system 2 usually adds one electromechanical ground overcurrent backup relay.

The philosophy of multi level protection dictates that we employ more than one relay to trip the line for the same type of fault. We would expect the level one relay to trip first, the level two relay to trip next if level one doesn't and so on. This idea is strengthened by using one system of current only relays such as current differential. This will continue to protect the line if there is a loss of potential on the other system. As described in the last paragraph, level one would be the zone distance/impedance protection. Level two would be the current differential relays, level three would be the permissive communications tripping, and level four would be the ground overcurrent backup relay.

1.2 Installation of Transformer Monitoring Equipment

The second aspect of the transmission project entails the installation of monitoring equipment on critical transmission transformers. Power transformers are some of the most expensive electric utility assets and are also very vital to the reliability of the transmission grid.

The on-line transformer monitor supplied by Serveron utilizes gas chromatograph technology to perform Dissolved Gas Analysis (DGA) of the transformer oil. DGA testing consists of taking transformer oil samples to determine the levels of eight critical fault gases. These gases are hydrogen (H2), oxygen (O2), carbon dioxide (CO2), carbon monoxide (CO), methane (CH4), ethylene (C2H4), ethane (C2H6), and acetylene (C2H2).

Before the availability of real time monitoring, the typical time to physically collect an oil sample in the field, send to a lab for analysis, and await the test results would be two or three days. Oil levels could change dramatically within this period, so having the data available in real time is a distinct advantage in maintaining the life of a transformer.

2 Transmission Line Protection Philosophy

Protective relays are devices that constantly monitor the lines and power equipment used in the transmission system. When problems occur on the power system, protective relays quickly determine the area of trouble and initiate corrective action to isolate the problem and limit damage to equipment and personnel. This timely action permits the rest of the system to maintain a high degree of service continuity and reliability.

As figure 1 illustrates, relaying components monitor circuit voltage and current parameters and are designed to operate automatically to disconnect the protected elements from the transmission system. Protective relay outputs initiate power circuit breaker tripping to isolate electrical faults (typically in 2 – 5 cycles) and protect power equipment from damage due to voltage, current, and/or frequency excursions outside the design capabilities.

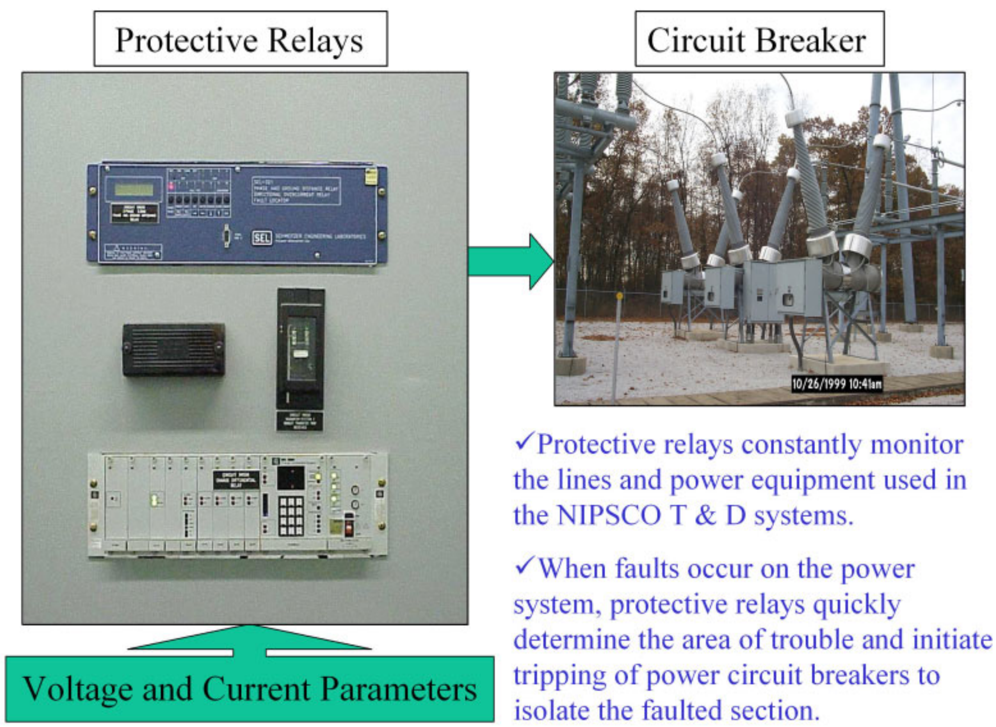


Figure 1

The key performance criteria for protective relaying schemes are:

- DEPENDABILITY - The relaying scheme must operate correctly every time a fault occurs within the defined zone of protection.
- SECURITY – The relaying scheme must not operate for faults outside its zone of protection.
- SELECTIVITY – The relaying scheme must be able to detect an electrical fault and affect the least amount of equipment possible when isolating the faulted section.
- SPEED – The relaying scheme must operate in a timely manner (usually within 1 - 2 cycles) to minimize equipment damage and maintain stability of the power system.

The proper operation of protective relaying schemes during fault conditions has a direct impact on increasing asset life of the protected equipment and minimizing system disturbance time. Relay or control malfunctions that cause false tripping lead to unnecessary customer outages and affect overall system reliability. These criteria are especially important to the large industrial customers that our transmission system serves.

Achieving relaying and control system reliability for high voltage transmission line protection requires an appropriate level of redundancy and back-up systems. Protection systems for these lines usually consist of two independent protection groups each using a different relaying design philosophy and each of which is capable of performing the required protection functions. For 345KV line protection NIPSCO typically employs a phase and ground step zone distance (impedance) package as system one. System two is a line current differential protection scheme with directional ground overcurrent as further backup. Both systems employ Permissive Overreaching Transfer Trip (POTT) as a high-speed pilot-relaying scheme. This scheme requires that a reliable communication system be established between both ends of the protected circuit. The media used for this communication system can be microwave radio, power line carrier, or fiber optic cable. The relays at each end of the line communicate with each other over the designated channel providing high-speed protection over the full length of the line for all fault types.

3 Protective Relaying Equipment Selection

Over the history of electrical system protection there have been three generations of protective relaying technology. Electromechanical protection equipment, which dates back to the time of Thomas Edison, was the mainstay of system protection for nearly 100 years. Solid State technology became prevalent during 60's and remained popular until the mid 80's. Solid State equipment did essentially the same function as electromechanical relays but used solid state components (diodes, transistors, RC networks) instead of coils and induction disks.

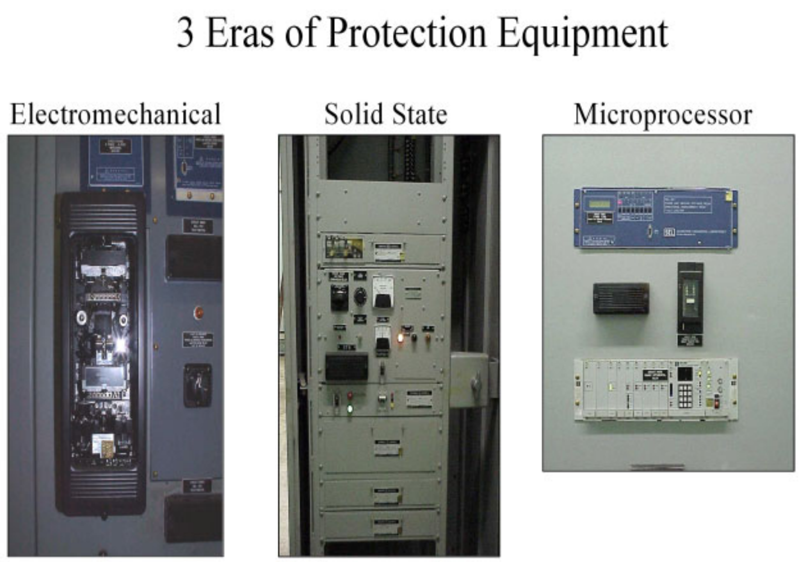


Figure 2

The advent of the computer led to the development of microprocessor based protective equipment. This technology has distinct advantages over the previous generations of protective equipment among which are:

- Self diagnostic testing
- Oscillography/Digital Fault Recorder (DFR) Event Reporting
- Sequence of Events (SER) reporting
- Fault Location
- Supervisory Control and Data Acquisition (SCADA) Integration
- Breaker Monitoring
- Multifunction Programmability

There are many manufactures of microprocessor based protective relays, most of which provide the same features and functionality. Among the first to bring microprocessor relays to the market was Schweitzer Engineering Laboratories (SEL). NIPSCO's experience with SEL products over the past twenty years has shown them to be superior in regard to performance, service, functionality, and reliability. For that reason, while we continue to evaluate and utilize products from other manufacturers, the majority of our protection schemes utilize SEL equipment. The 345KV line protection modernizations associated with this project will utilize SEL relays for System 1and 2 with an ABB directional ground relay used as a backup.

3.1 System 1 Protection – SEL-421

The primary protection for the 345KV circuits will be provided by SEL-421 relays. The SEL-421 relays in this application will provide four zones of phase and ground distance protection with directional overcurrents serving as backup. Communication between the relays at each end of the circuit will be done over digital microwave. This channel will facilitate Permissive Overreaching Transfer Trip (POTT) as well as a Direct Transfer Trip (DTT) scheme that is used for breaker failure protection.

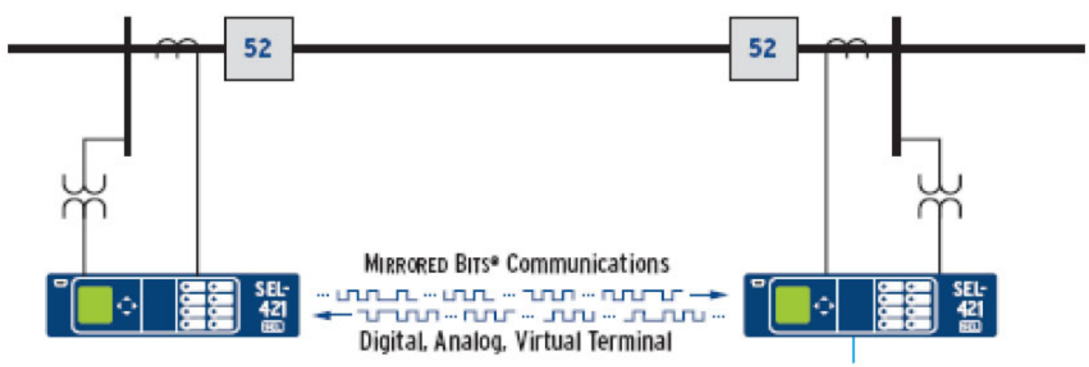


Figure 3

The major reason for selecting the SEL-421 relay as the system one protection is the combination of speed and reliability that this relay affords. This relay has shown itself to provide secure sub cycle fault detection.

3.2 System 2 Protection – SEL-311L

The secondary protection for the 345KV circuits will be performed by SEL-311L relays. The SEL-311L relay uses a vector ratio of the local and remote phase and sequence currents to provide high speed current differential protection. The SEL-311L relay also includes complete step zone distance protection with directional overcurrents serving as backup. POTT and DTT schemes are integrated in the protection.

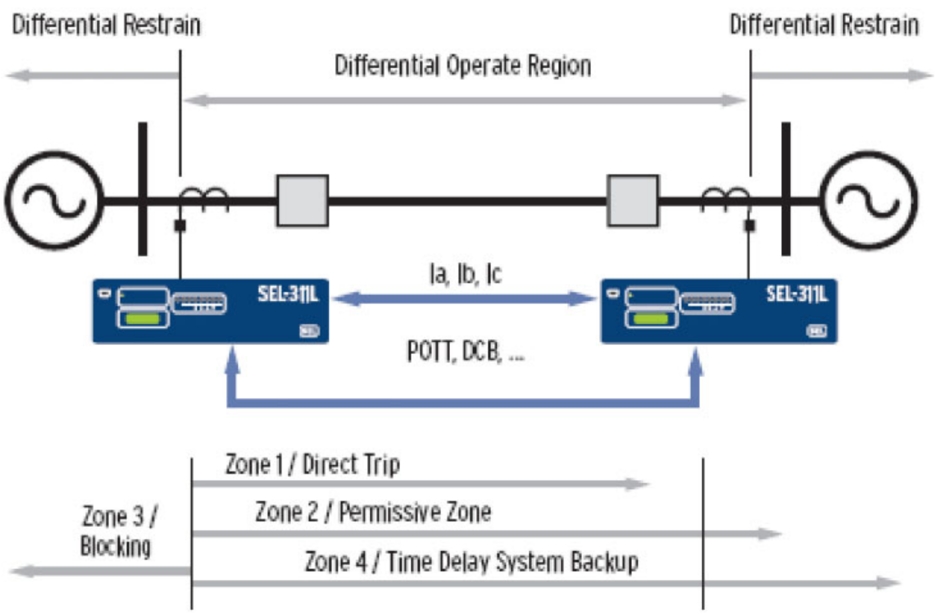


Figure 4

One of the main benefits of using a current differential scheme is that the protection is not compromised by the loss of a single potential transformer (PT) fuse failure. When designing the protective systems, the objective is to have a blanket of protection that is sufficiently robust to survive any single point of failure.

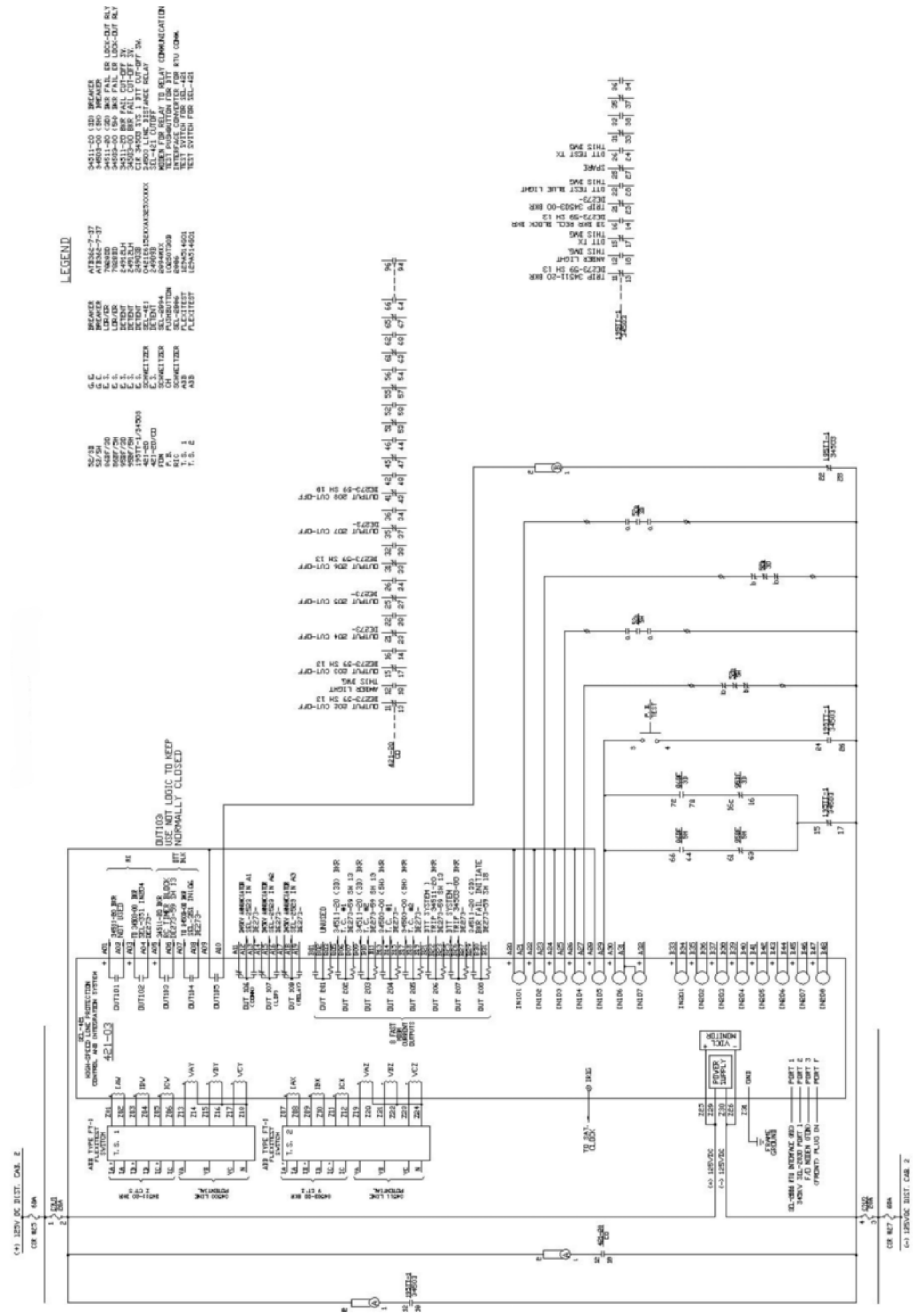
3.3 Backup and Ancillary Protection

While microprocessor relays have led to vast improvement in system protection, electromechanical relays do have a few enduring advantages. Electromechanical relays are extremely hardy devices with over a hundred years of design research. They are not dependent on an external power supply to function. They don't have A/D converter or ROM failures due to alpha particle transmissions. Electromechanical relays are essentially passive devices that can operate for decades without failure. For this reason, NIPSCO's philosophy for transmission line protection is to include one electromechanical protection relay. Since seventy five percent of all faults involve ground, a directional ground overcurrent relay is employed (typically an ABB IRD-9 or a GE JBCG).

For breaker protection and control, an SEL-351 relay is used to provide automatic reclosing, synchronizing, SCADA control, and breaker failure protection. All microprocessor relays receive a satellite synchronized time and date signal. They are also connected to the Electric Dispatch Energy Management System (EMS) via a Distributed Network Protocol (DNP) channel.

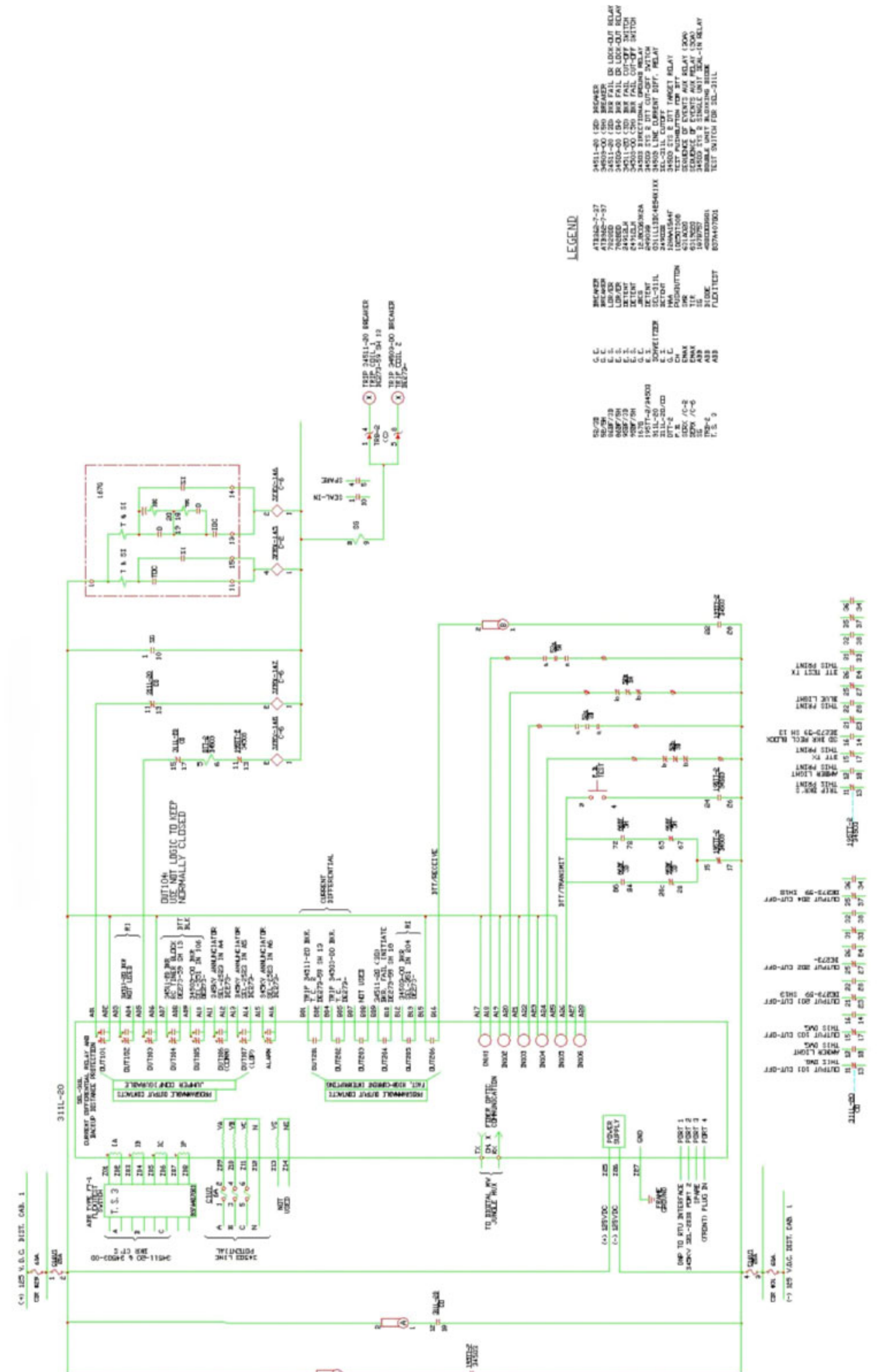
4 Protection Scheme Designs

A sample of DC Schematics for the 345KV line protection schemes associated with this project are shown in Figure 5 and 6 on the following pages:



System 1 – SEL-421 Schematic

Figure 5



System 2 – SEL-311L and Backup Directional Ground Overcurrent Schematic

Figure 6

5 Transmission Line Monitoring Requirements

Automatic transient recording devices such as oscillographs (older analog technology) and digital fault recorders - DFR (newer microprocessor technology) are essential for monitoring the performance of protective equipment in modern power systems. The newer microprocessor based relays, such as the SEL-421 and SEL-311L relay that are being used in this project are equipped with DFR capability *(SEL calls it simply Event Reporting)*. The relays also capture sequence of events (SER report). These devices and relay functions that record analog voltage, current and equipment operations, are invaluable tools in the investigation of electric system events and their post fault analysis. The results of this monitoring have reduced downtime and equipment losses, which leads to greater system reliability and customer satisfaction. Transmission monitoring tools have provided critical data for documentation and review of system events such as the widespread outage of August 14th, 2003. In recent years, the various national reliability councils have begun to develop standards for mandatory time synchronized disturbance monitoring. Due to the extensive use of microprocessor relays like the ones used in this project, and the installation of dedicated DFR and SER units, NIPSCO is positioned to be in full compliance with Reliability First/ NERC Reliability Standard PRC-002.

6 345KV Line Upgrade - Protective Relay Installation & Commissioning

As with any large scale project, a great deal of coordination and project planning is necessary to insure that all the engineering, procurement, construction, operations, and field testing functional areas work together to ensure a successful outcome. Therefore, a number of interdepartmental meetings take place at various stages of the project including, pre-engineering and preconstruction. These meetings/tele-conferences ensure that all parties are aware of the scope of the project and the project schedule for equipment arrival, engineering print release, construction start, electrical clearances, and project completion. Installation and commissioning of protective relaying schemes and equipment is done under the oversight of Field Technical Services engineers. These engineers are responsible for

a. Testing and setting of all protective relay and control equipment
b. Verifying that the engineering drawings are accurate and error free
c. Certifying of all prefabricated relay panel wiring
c. Overseeing the deconstruction of old protection equipment (safety and accuracy)
d. After substation engineers come up with interconnection wiring and their prints. Technical Services engineers check all new interconnection wiring
e. Functional testing of the new protection schemes
f. Performing satellite synchronized end to end commissioning tests
g. Completing load checks upon energization of new protective schemes/equipment
h. Marking up engineering print, relay information, and protective settings documentation

6.1 Protective Relay Acceptance

The 345KV line modernizations associated with this project will utilize SEL relays for System 1 and 2 protection with an electromechanical relay employed as a directional ground backup.

System 1 – SEL-421 with Permissive and Direct Transfer Tripping

System 2 – SEL-311L with Permissive and Direct Transfer Tripping

Backup Protection – - ABB IRP-9 (Directional Ground Overcurrent) or
- GE JBCG (Directional Ground Overcurrent)

Breaker Control – SEL-351

All protective relaying devices are acceptance tested to ensure proper operation prior to being placed in the field. The equipment is lab tested according to the manufacturer's specifications. This is true for electromechanical relays and auxiliary devices such as:

Protective Relays – Directional Ground (GE-JBCG, ABB- IRP-9)
Metering Equipment – Digital Ammeters, Voltmeters (Bitronics , ARGA)
Auxiliary Tripping devices – Lockout relays and trip relays (LOR or GE-HGA)

All microprocessor based devices are acceptance tested to ensure proper self check functionality. Furthermore, to test the relay's analog inputs, three phase current (1 amp) and potential (67 V) are fed to the relay with a 30 degree (I lag E) PF angle. The relay's meter function is then used to verify the proper functioning of the A/D converter. Relay inputs are asserted and the output contacts are pulsed.

6.2 Equipment Installation Practices

345KV protective relay modernization projects typically require extended circuit outages (3-4 weeks). To minimize the system impact, such projects are often scheduled when moderate weather is anticipated (Spring and Fall). When project timing is not advantageous, NIPSCO employ's the use of temporary relaying panels to limit circuit clearances to only two days: one day at the beginning and one day at the end of the project. While this practice has proven to be extremely valuable under adverse conditions, utilizing temporary panels increases the complexity and duration of the project. While adequate, the circuit protection provided by the temporary panels is also less than ideal. For the modernization associated with this project, timing allowed for 3 week outages, therefore the temporary panels were not required. For each circuit, the proper line and breaker clearances were acquired. The protection and control circuits were de-energized and the old relay panels were unwired and removed from service. Relay modernization projects entail a tremendous amount of wiring changes. For the Babcock project there were 43 pages of wiring removals. Five panels and more than 30 electromechanical relays were retired from service.

Babcock – Wiring and Relay Panel Removals

Four new relay panels were installed. The new interconnection wiring to neighboring panels was run (233 inter-panel wiring additions). All wiring was thoroughly checked by conducting continuity tests (commonly referred to as buzzing).

Old Babcock Relay Panels

New Babcock Relay Panels

The prior pictures illustrate one of the many advantages of the modern microprocessor relays. They are multifunctional, i.e. one SEL relay performs the functionality of an entire panel of electromechanical relays. As a result, new panels contain fewer relays (fewer points of failure), while providing more advanced and redundant levels of protection.

Coinciding with the relay modernization project at Babcock was the replacement of a 345KV Breaker.

Old Air Blast Breaker

New SF-6 Breaker

6.3 Relay Settings Development

The NIPSCO Transmission Planning and System Protection group is responsible for maintaining the T&D system model. Short circuit analysis is performed using Aspen Oneliner to develop impedance and overcurrent settings for the protective relays.

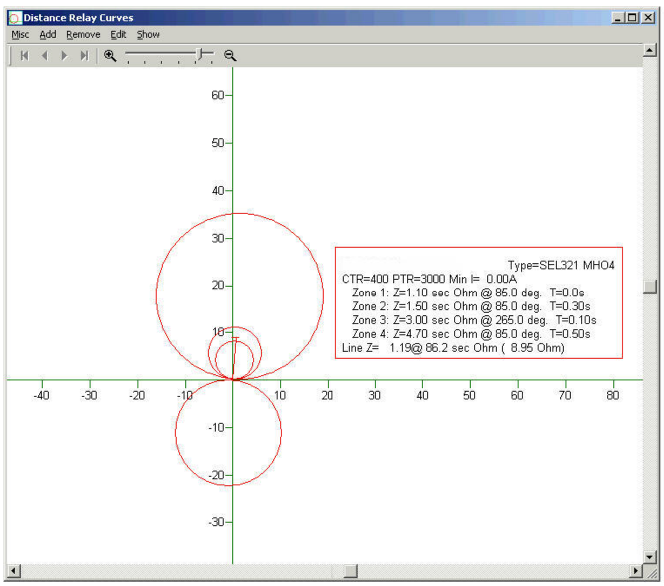


Figure 7

Once the new protection and control relays (SEL-421, SEL-311L, and SEL-351) have been accepted, they are set according to the results of the short circuit analysis. Note: Many of the settings on the new microprocessor relays are not directly related to the impedance and overcurrent protection functions. With the advent of SEL relays, much of the DC control logic once performed by auxiliary relays have now been migrated within the microprocessor relay. As a result, the settings are much more extensive (e.g. the settings on the SEL-421 are over 100 pages long).

6.4 Field Testing and Commissioning

The new control and protection schemes were fully functional tested. Every breaker trip, close, and auxiliary function is checked. Final commissioning of the new protection schemes includes the use of satellite synchronized Doble 6150 units. State simulations of various line faults are created from Aspen One-liner and used to simulate actual faults within the various zones of protection. A full battery of tests are run that include 3 phase, phase to phase, and phase to ground faults at various locations inside and outside the circuits zone of protection. The relay responses and event report data are carefully analyzed to verify and ensure that performance measures up to industry standards. After all commissioning tests had been completed, the circuit is returned to service.

7 Transmission System Modernization Results

Modernization of transmission line protection has numerous positive impacts upon performance and reliability of the transmission system[1].

7.1 Self Diagnostic Testing

The self diagnostic testing of the SEL-421 and SEL-311L relays allow equipment failures to be detected immediately instead of waiting for the next round of periodic testing or worse, a misoperation. The microprocessor relays also require less maintenance which allows limited manpower to be utilized more effectively and productively.

Both relays perform a variety of self tests. The SEL311L takes the following corrective actions for out-of-tolerance conditions.

- Protection Disabled: The relay disables overcurrent elements and trip/close logic. All output contacts are de-energized. The EN front-panel LED is extinguished.
- ALARM Output: The ALARM output contact signals an alarm condition by going to its de-energized state.
  - If the ALARM output contact is a B contact (normally closed), it closes for an alarm condition or if the relay is de-energized.
  - If the ALARM output contact is an A contact (normally open), it opens for an alarm condition or if the relay is de-energized. Alarm condition signaling can be a single 5-second pulse (Pulsed) or permanent (Latched).
- Line Current Differential Protection Disabled: The relay disables 87L protection and de-energizes outputs OUT201– OUT206. Relay Word bit 87LPE deasserts and Relay Word bit 87HWAL asserts.
- The relay generates automatic STATUS reports at the serial port for warnings and failures.
- The relay displays failure messages on the relay LCD display for failures.

By using the serial port STATUS command or front-panel STATUS pushbutton, the relay self-test results can be viewed.

[1] Examples of actual data recorded by the relays in this project are designated Critical Energy Infrastructure Information (CEII), and are not included in this report.

7.1.1 Self Diagnostic Testing Summary

The Figure below shows the different self tests that the SEL-311L relays performs.

Self-Test	Condition	Limits	Protection Disabled	ALARM Output	Description
IA, IB, IC, IP, VA, VB, VC, VS Offset	Warning	30 mV	No	Pulsed	Measures the dc offset at each of the input channels every 10 seconds.
Master Offset	Warning	20 mV	No	Pulsed	Measures the dc offset at the A/D every 10 seconds.
	Failure	30 mV	Yes	Latched	
+5 V PS	Warning	+4.80 V +5.20 V	No	Pulsed	Measures the +5 V power supply every 10 seconds.
	Failure	+4.65 V +5.40 V	Yes	Latched	
+5 V REG	Warning	+4.75 V +5.20 V, –4.75 V –5.25 V	No	Pulsed	Measures the regulated 5 V power supply every 10 seconds.
	Failure	+4.50 V +5.40 V, –4.50 V –5.50 V	Yes	Latched	
+12 V PS	Warning	+11.50 V +12.50 V	No	Pulsed	Measures the 12 V power supply every 10 seconds.
	Failure	+11.20 V +14.00 V	Yes	Latched	
+15 V PS	Warning	+14.40 V +15.60 V	No	Pulsed	Measures the 15 V power supply every 10 seconds.
	Failure	+14.00 V +16.00 V	Yes	Latched	
TEMP	Warning	–40° C +85° C	No		Measures the temperature at the A/D voltage reference every 10 seconds.
	Failure	–50° C +100° C	Yes	Latched	
RAM	Failure		Yes	Latched	Performs a read/write test on system RAM every 60 seconds.
ROM	Failure	checksum	Yes	Latched	Performs a checksum test on the relay program memory every 10 seconds.
A/D	Failure		Yes	Latched	Validates proper number of conversions each 1/4 cycle.
CR_RAM	Failure	checksum	Yes	Latched	Performs a checksum test on the active copy of the relay settings every 10 seconds.
EEPROM	Failure	checksum	Yes	Latched	Performs a checksum test on the nonvolatile copy of the relay settings every 10 seconds.
I/O BRD	Failure		No	Pulsed	Verifies correct I/O board is installed. Identifies when a board is changed or disconnected.
87L RAM	Failure		87L only disabled	87HWAL asserted; pulsed	Periodically performs a read/write test at each RAM location.
87L ROM	Failure	checksum	87L only disabled	87HWAL asserted; ALARM pulsed	Performs a checksum test on program storage ROM.
CHAN X CHAN Y	Failure		Determined by 87LPE	None	See *87L Communications Monitoring on page 10.6*.
FPGA	Failure		87L only disabled	87HWAL asserted; ALARM pulsed	Ensures FPGA configures properly.
BOARD	Failure		87L only disabled	87HWAL asserted; ALARM pulsed	Checks each processing interval to ensure dedicated 87L hardware responds and the watchdog timer has not expired.

Figure 8

7.2 Remote Interrogation Features

The remote interrogation features allow for almost immediate access to the relays settings and/or event report data. System changes that require protection or automation setting alteration can be performed in minutes rather than hours or days. The event reports and sequence of events can by analyzed within minutes of the system event. The root cause of the system disturbance can be identified and a restoration plan developed before first responders arrive at the scene.

7.2.1 Experience with Remote Interrogation Features

The microprocessor relays at the terminal ends were equipped with a communications processor (SEL-2030) and telephone line sharing switch (Teltone SLSS). The relays were time synchronized through the SEL-2030 via a satellite clock. All the communications equipment and protective relays were secured with multilevel passwords. This design allows for the speedy interrogation of any fault event or setting change. Shortly after the Babcock terminal went in service, a problem was uncovered with the motor operated disconnect control within the SEL-351 relay on the breaker. Remote interrogation made the trouble shooting and subsequent scheme changes straightforward with minimal time required.

7.3 Fault Location Features and Experience

Fault location data that is readily available from the relays has proven to be an invaluable tool for helping field personnel find "hard to find" faults. Fault location within the relays has shown itself to be accurate to within a pole length. In addition to fault location, both systems of protection on each circuit is equipped with sequence of event recording, historical event logging, and oscillographic of event data. A log file of a recent event data for a terminal at St. John included detailed information of fault location and magnitude along with oscillographic data of a BC phase fault caused by galloping conductors during an ice storm.

7.4 SCADA Features and Use

The incorporation of SCADA functions within the protective relaying makes for an improved scheme design. Since both systems are monitoring analog quantities, equipment status, and performing control operations, it makes sense to allow the protective relaying to be the conduit through which SCADA is performed. The elimination of redundant systems makes for a vastly superior field installation.

The remote terminal unit within the substation (GE Harris D20) communicates with the microprocessor relays via an RS485 communication channel which employs Distributed Network Protocol (DNP3). Analog, status, and control maps are set within the relay to select which elements are to be polled by the RTU and subsequently forwarded to the Energy Management System (EMS).

7.5 Transmission Line Protection Overall Features

The newer protection schemes are: faster, more reliable, easier to install, easier to maintain, provide vastly improved monitoring features, offer greater flexibility, and give better overall protection.

8 Transformer Monitor Installation

The second aspect of this Transmission project relates to the installation of monitoring equipment on transmission transformers. As an asset class, transformers constitute one of the largest investments in a utility's system. For this reason, transformer condition assessment and management is a high priority. Each utility's grid is unique and investment levels in asset condition and assessment tools vary according to risk level and investment return models. While the models are different for each utility, the common element in them is that transformer fleets are stratified according to the criticality of individual transformers. The variability and uniqueness lies in where the prioritization lines are drawn and the investment amounts allocated for asset condition and management tools for each level. Typically this approach has the most critical transformers receiving the highest investment of condition assessment and decreases for each less critical level identified.

Transformers have a finite life. In the US, with an average age of almost 40 years, many are now approaching the end of their design life. Higher loads placed on transformers, in an environment that demands higher electric energy consumption, have taken their toll on transformer longevity. Compound this with the reduction in capital budgets, the need to closely manage transformer assets becomes essential. Utilities attempt to avoid unplanned failures, lower maintenance costs and defer capital expenditures through the appropriate use of transformer condition assessment and management tools.

Monitoring the state of power transformer health, a key component in the path of reliable power, has traditionally been accomplished using laboratory Dissolved Gas Analysis (DGA) tests performed at periodic intervals. DGA of transformer oil is the single best indicator of a transformer's overall condition and is a universal practice today. However, on-line DGA helps utilities avoid unplanned failures, adopt lower cost condition-based maintenance, and defer capital expenditures by extending the transformer's useful life.

First generation (1970's), as well as some current on-line DGA products available today, provide Total Combustible Gas (TCG) or single gas (Hydrogen) monitoring. These products provide indication of developing problems in the transformer but offer no legitimate diagnostic capability. On-line DGA offerings in the market have evolved from this early approach to include multi-gas monitors that detect and analyze some or all of the eight fault gases identified in the IEEE and IEC standards as well as provide diagnostic capability.

Newer on-line DGA products have the unique ability to continuously trend multiple transformer gases and correlate them with other key parameters such as transformer load, oil and ambient temperatures as well as customer specified sensor inputs. This capability enables utilities to relate gassing to external events, a key to meeting utility reliability and financial goals in the current environment. A study has also shown that some on-line DGA tools offer better accuracy and repeatability than laboratory DGA. This on-line DGA can improve the decision timeliness and confidence when incipient faults are detected.

9 Transformer Monitoring Equipment and Design

On line real time oil analysis monitoring takes the place of manually taking transformer oil samples and sending them away for laboratory analysis. Traditional laboratory analysis utilizes a gas chromatography process. Eight (8) dissolved gases can be found through DGA testing – Hydrogen (H_2), Oxygen (O_2), Methane (CH_4), Carbon Monoxide (CO), Carbon Dioxide (CO_2), Ethylene (C_2H_4), Ethane (C_2H_6), and Acetylene (C_2H_2). These gases are created in the oil from arcing, thermal heating, and corona effects. The types and amounts of gases present can help determine the type and intensity of the fault creating these gases.

On line transformer monitors include units manufactured by Serveron, Kelman and others. Each can provide real time monitoring of the eight dissolved gases. The Serveron unit uses the traditional gas chromatography process, whereas the Kelman monitor utilizes a photo acoustic spectrometer process. Based on our operating department's familiarity with the gas chromatography process, the Serveron unit was chosen for this project.

A typical Serveron monitor installation is shown in figures 9,10 and 11. Figure 9 is the transformer monitor mounted on brackets to the side of the transformer case. Figure 10 is the monitor with its swing cover open to show an internal electrical panel containing the electronics to monitor the gas levels and for interfacing AC power and communications to the monitor. Figure 11 details the oil supply lines from the oil moisture and temperature sensor connected to an existing oil port near the top of the transformer to the monitor.

Figure 9

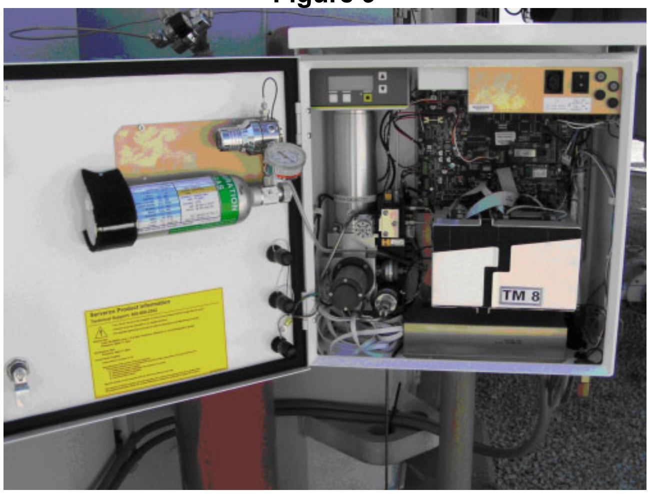


Figure 10


ABB
ASEA BROWN BOVERI
SERVERON
On-line Transformer Monitor
MODEL TM8
ALARM
SERVICE
POWER

Figure 11

10 Transformer Monitor - Installation & Operation

Serveron provides a detailed checklist of site preparation steps to be taken prior to installation. These include:

- Choosing oil supply and return ports
- Choosing a cabinet mounting location
- Providing AC Power
- Determining need for optional oil inlet cooler
- Choosing a communication protocol
- Determining need for optional moisture and oil temperature sensor
- Ordering helium
- Ordering stainless steel tubing

After these steps are completed installation can begin.

10.1 Transformer Monitor Installation

The monitor operates by removing oil from the transformer, analyzing the oil, and returning the oil to the transformer. Oil is supplied from the top of the transformer and returned at the bottom of the transformer. The oil supply port should be at a location on the transformer to provide a well mixed sample of the transformer oil, which is typically at a top tank valve. The transformer's bottom drain valve is used for oil return.

The monitor itself is mounted within an approximate 21-1/4" wide x 20" high x 11" deep outdoor cabinet. It can be mounted on the side of the transformer in a location not interfering with any transformer operation or maintenance duties, or on a separate mounting pedestal which would be attached to the transformer or a separate foundation.

Once the mounting location is determined, ¼" stainless steel tubing is procured and used to connect the top and bottom oil ports to the monitor to provide the oil supply and return paths. Tubing should be in continuous lengths in order to avoid using fittings and to reduce the possibility of leaks. Teflon tape should be installed on all connections, as necessary.

An external helium tank, used as a carrier gas to help send the sampled gases through the chromatograph, is attached to the side of the transformer and connected by tubing to the monitor. Also, a gas verification cylinder is mounted inside the monitor cabinet. This cylinder is used to calibrate the monitor and contains a trace amount of the previously mentioned eight transformer fault gases.

AC Power and communication and sensor cables are connected within the monitor cabinet and externally to the substation service source and the communications network.

10.2 Transformer Monitor Operation

Oil is circulated from the transformer to the monitor and back to the transformer. The frequency of the analysis can be performed at various intervals with a four hour interval being set as the default. The analysis takes about 40 minutes. Data is accumulated every time a Dissolved Gas Analysis is done. This data is stored within the monitor’s memory, which holds about 2 years of data.

The Serveron monitor is calibrated at the factory, after installation, and self calibrates every three days.

Data retrieval, setting of caution and alarm levels, and analysis intervals can be set by using the Serveron TM View software.

11 Experience with Use of On Line Serveron Gas Chromatography Monitor

There are immediate benefits to the use of on-line monitoring of combustible gasses via the Serveron TM8.

The Serveron TM8 units are utilized to trend combustible gasses daily and to report any increased gas trending as an alarm. The unit also will detect and alarm if any one gas alarm limit is reached. This will identify any concern that might happen suddenly and give us the opportunity to take the transformer out of service, and through testing, identify any underlying issue prior to a catastrophic failure. Caution and alarm limits are set manually in the Serveron TM View software (Figure 12)

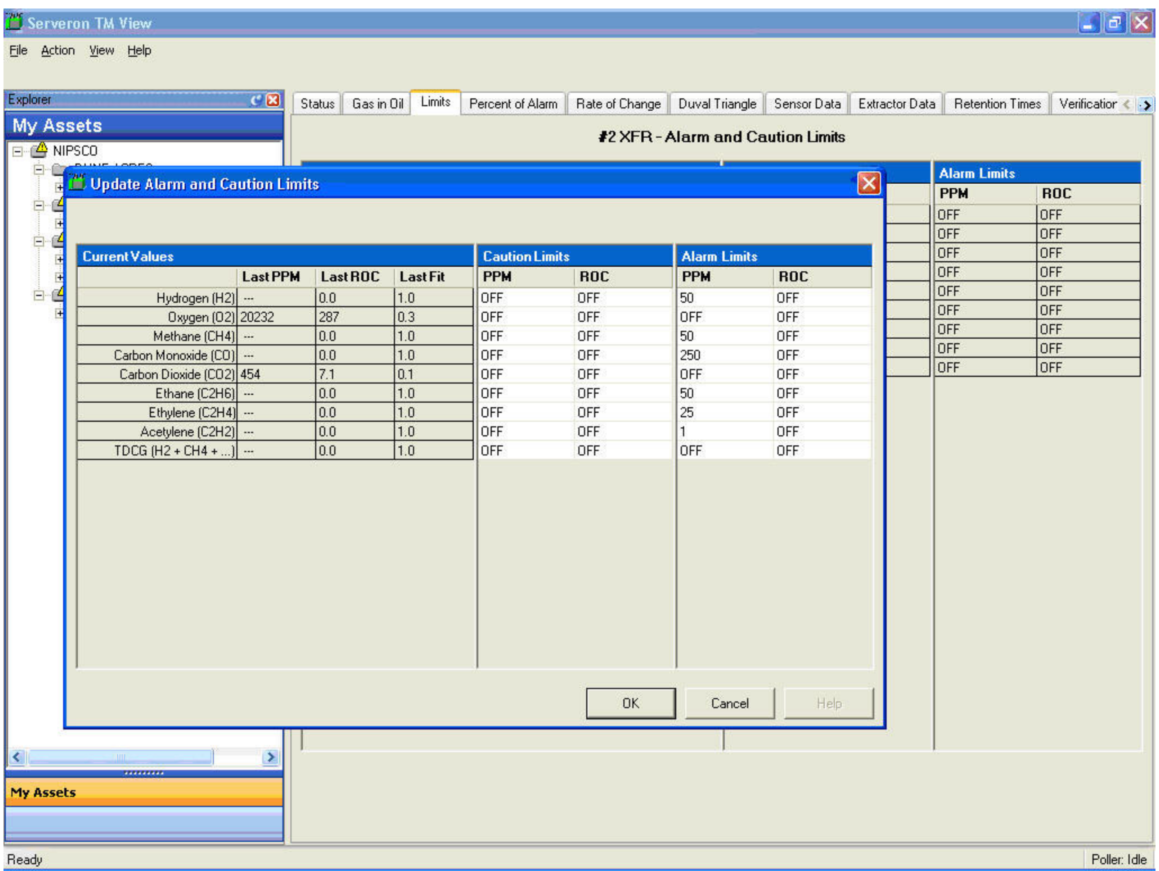


Figure 12

View from the Serveron TM View software limits setting tab

NIPSCO's alarm limits are as follows for 345kV class transformers:

Gas	Parts per Million
Hydrogen	50ppm
Methane	50ppm
Acetylene	1ppm
Ethylene	25ppm
Carbon Monoxide	250ppm
Moisture Level	25ppm

Each transformer had a baseline dissolved gas analysis (DGA) sample drawn and sent to an outside test laboratory. Shortly after the Serveron TM8 commissioning, each Serveron unit sample results were compared to test results obtained from these laboratory tests. The Serveron units were found to be very accurate as all combustible gas and moisture level results matched the lab results within several ppm.

Serveron TM8 utilizes the Duval Triangle gas relationship of Acetylene (C2H2), Methane (CH4) and Ethylene (C2H4). If a condition exists that has the three mentioned gasses present, the levels of each gas is weighted to each other and an appropriate cause is identified. Here is a screen shot of the TM View software and Duval's triangle diagnostic feature.

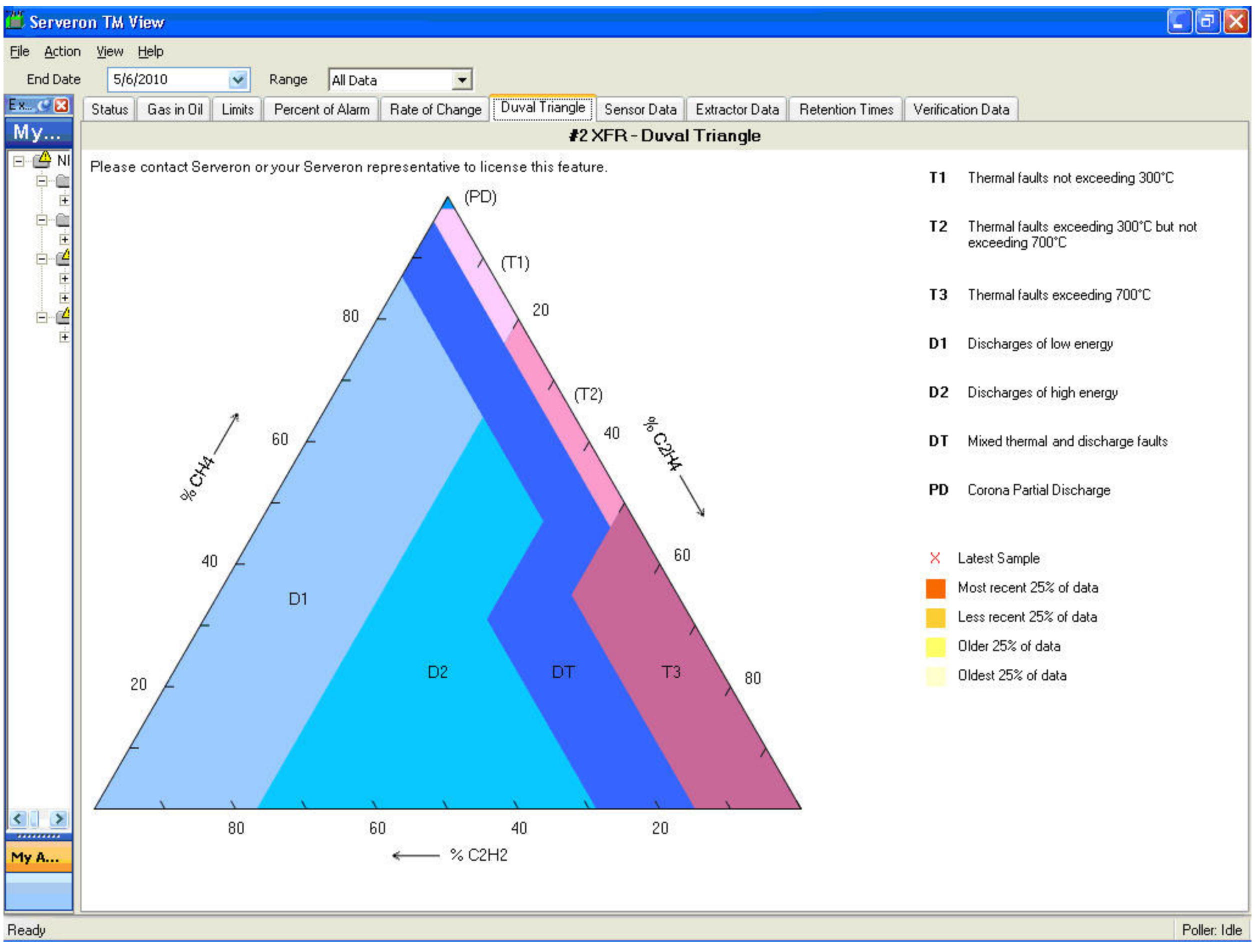


Figure 13

As we became more familiar with the Serveron units, we discovered several features that would improve the gas monitoring devices. The gas monitors did not have a user interface or display to view the gas levels without the use of a laptop computer. We worked with Serveron to incorporate a display to view the current gas levels and last sample date stamp. This feature would quickly identify any fault gasses and the last sample performed by our first responders in the case of a fault condition.

Figure 14 - TM8 DISPLAY

Each Serveron TM8 unit alarm contact is hard wired to an alarm annunciator panel located in the substation's relay house. This normally open alarm contact will alarm our dispatching department if an alarm threshold is met. The basic monitoring needs are met with this configuration, yet continuous monitoring would enhance the overall effectiveness of the Serveron TM8 units providing real time trending of data. The transformers equipped with the Serveron gas monitors are physically located in remote areas of our territory. Regular on-site downloads at these sites would require frequent extensive travel causing inefficiencies to the Technical Services department. We outfitted each Serveron unit with a cell phone modem that would allow us to download the gas monitors data on a routine schedule remotely from our office. Serveron Corporation worked with TMobile as their cell phone modem provider. We found that, depending on atmospheric conditions, the cell modems would not have a strong enough signal to communicate, thus rendering this technology a poor real time communication solution to access the Serveron gas monitors. We have recently accessed the Serveron units via RS485 communication interface, through internal fiber optic network across our company, allowing the real time access of the instrument remotely.

We currently have 9 Serveron TM8 gas monitors in service at NIPSCO. After several years of operation, we have experienced numerous issues with the Serveron TM8 units. We replaced the oil pump, helium and calibration gas bottles on one unit and the sled (main instrument component) and main board on the other unit.

Below are pictures of a few failed components:

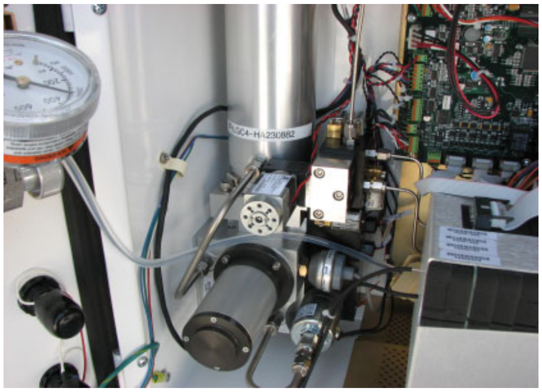


Figure 15
PUMP ASSEMBLY

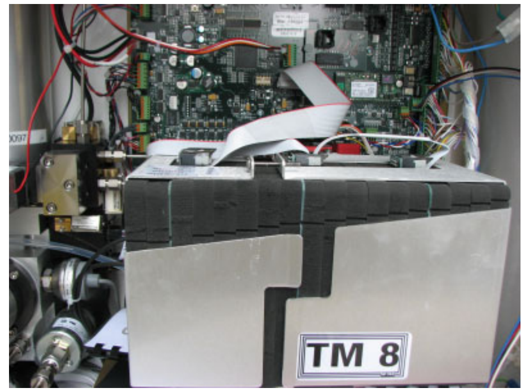


Figure 16
SLED ASSEMBLY WITH MAIN BOARD IN BACKGROUND

We have had multiple sled issues, moisture transmitter problems, pump concerns and display malfunctions.

The chronic issues we have been dealing with occur most frequently in the cold weather. January temperatures that fall into the single digit range cause many of the issues we continue to see with the Serveron units. After speaking with other utilities in the southern regions of our country, the concerns increase exponentially in the cold ambient temperatures. Serveron is aware of the cold weather issues and are in the process of engineering a cold weather climate kit. This kit is estimated to be complete and ready for production in the last quarter of 2010.

Although the Serveron TM8 units have not been robust, their field support service is always prompt and professional. The Serveron unit warranty is one year, yet Serveron has repaired all the issues we have had to date under warranty.

12 Distribution Project Introduction

NIPSCO's electric distribution underground infrastructure is approaching 40 years and is developing faults at an increasing rate. This presents a need to consider replacing cable at the end of its predicted life cycle or innovative alternate methods of proactively identifying only those sections of cable that require replacement. Replacement cost of this infrastructure is significantly greater than typical new installations because of established property owner obstacles (fences, pools, decks, sheds, gardens, etc) and other active underground utilities (natural gas, water, sewer, etc). The need to minimize interruptions during the replacement process is paramount to maintaining good customer relations. An average underground cable fault can take as much as 5 times longer to find and repair than an overhead line outage, which is typically visible to the electric line personnel.

The first step of the distribution project involves identifying and prioritizing areas to improve operations and reliability. Next, the prioritized areas are evaluated using a cable assessment technology which results in recommended actions for each section of cable. Finally, the recommended actions are reviewed and upgrades are implemented to improve operations and reliability in Northern Indiana.

13 Overview of Outage Locations

The first step in improving the electric underground infrastructure was to analyze the existing system configuration and define the selection criteria using all the available records on installed underground cable and fault history. Gathering all of the information from the available records was discovered to be a lengthy process and one that took extended time to gather and analyze.

The first step in defining the selection criteria was to analyze data that is available that would indicated where outages occur based on underground primary faults. In addition to location, the quantity of outages for the same location is one measure of severity that will contribute to priority of importance.

In order to establish a visual baseline of this data, it was decided to create a graphical map of each Local Operating Area's (LOA's) existing trouble area. This map was created using data from the NIPSCO Outage Restoration System (NORS) and then displayed in a Geographic Information System (GIS) application called ArcMAP. Each interruption location appears as a graphical representation on the map along with the major roads, with increasing interruptions being displayed by different colors as shown in a single LOA example Figure 17 and 18.

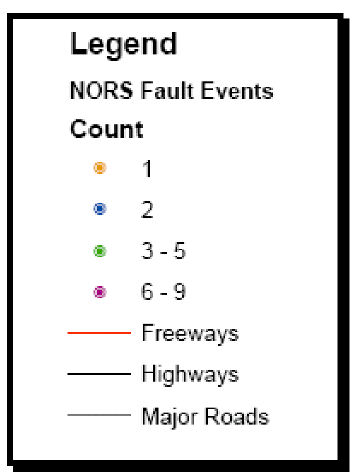
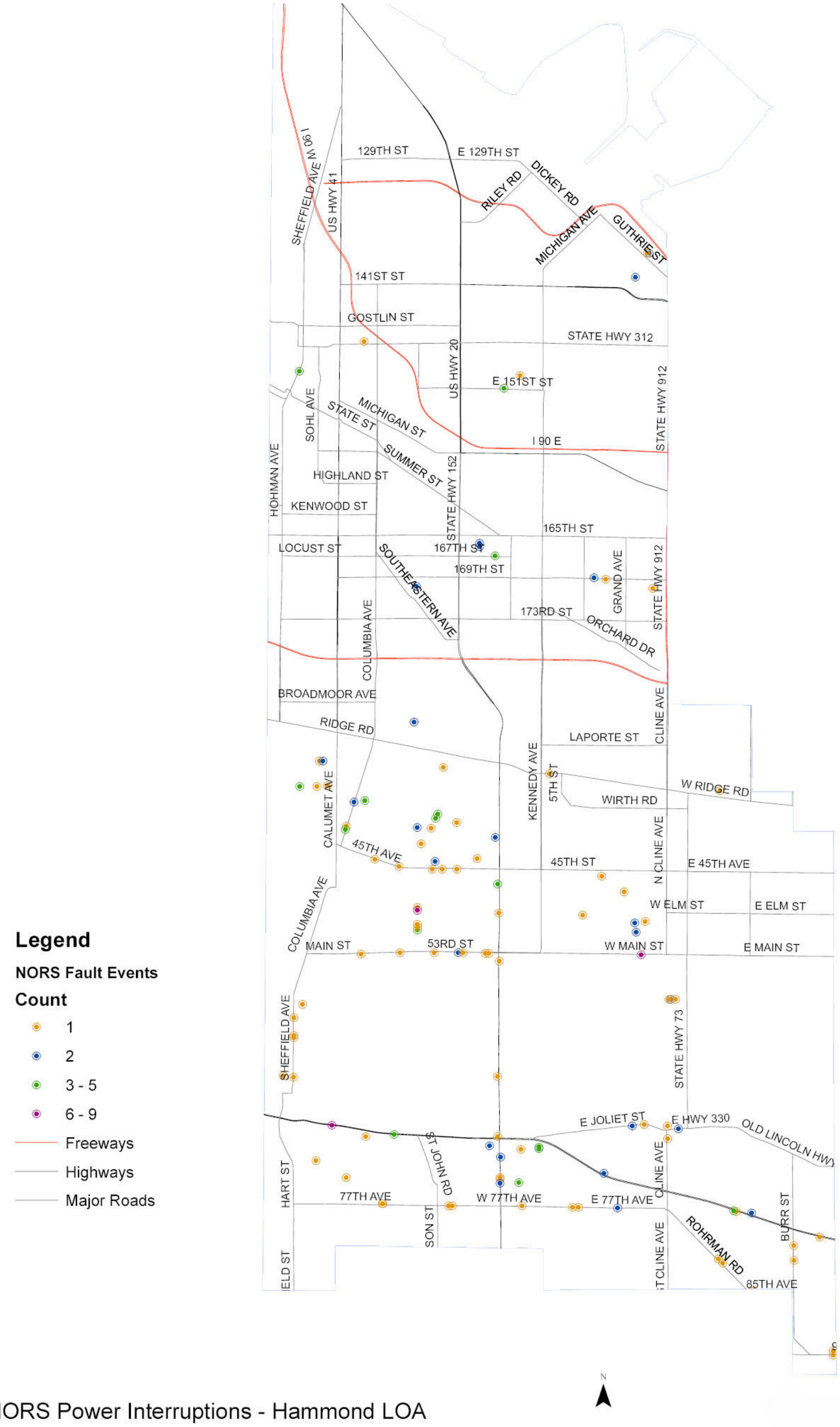


Figure 17 Legend for Overview Map



NORS Power Interruptions - Hammond LOA

Figure 18

After review of the data in each of the maps, the conclusion from the team was that this data and map was a good overview of the enormity of the issue, but the NORS data alone would not be enough information to define our selection criteria for the scope of this project. The next step was to gather additional information on fault history.

14 Evaluate Available Fault History on Installed Underground Cable

There are 2 sources of records for fault history of underground cable. The first source of records was from the NIPSCO Outage Restoration System (NORS). This system was installed in September of 2000, and directs customer calls about an outage to a central system where the calls are tracked. When the outage was finally resolved, the outage was classified and can later be retrieved for reporting purposes.

The second was fault records from paper forms. Since 1998, NIPSCO has had an internal procedure for the prioritization of cable replacement projects. The goal of this procedure was to "establish the criteria for underground distribution cable replacement and determine the priority for distribution cable replacement". Under this procedure, a form was submitted to track primary cable failures and the types of repairs made in order to make a reasonable prediction of our current and future replacement needs. Over time, the forms accumulated to the point where a database was needed to keep track of the data. This database of fault forms is a key piece of data in the selection criteria, but the records gathered may also not be complete for various reasons.

14.1 Underground Fault History (Failure Report Form)

Extensive work was done to validate and enhance as much of the data as possible. In order to have a table or database that would relate the fault form records to other data that was being collected, additional fields were added to the database version of the form so that the records could be validated and key fields could be populated with a correctly formatted identification. The fields that were added were the Outage Source, From Location 1, and To Location 2. Each record in the database was validated by finding the source location in our GIS system and then locating the section of cable defined by location 1 and location 2. If all three points were valid, then the record was considered valid. Each of these fields defines a unique identification of a device, and when all three are used together, they define a unique piece of cable that is traceable to a unique source in other records.

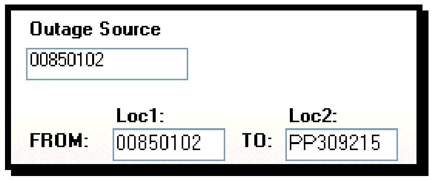
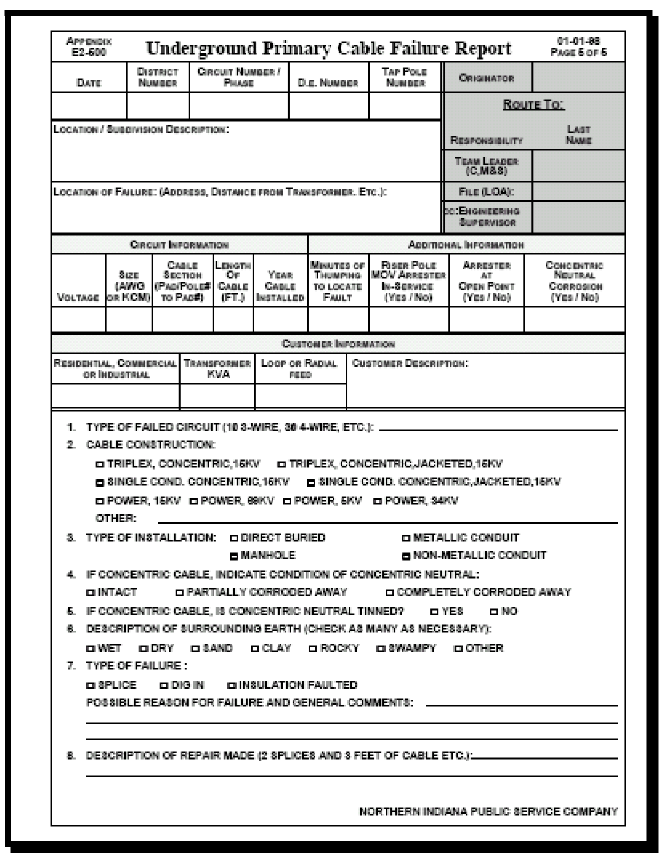


Figure 19 New Database Fields Added

During this process, any new faults that occurred were still submitted on paper forms and then the key information was entered into the database.



APPENDIX E2-600 | **Underground Primary Cable Failure Report** | 01-01-98 PAGE 5 OF 5

Date	District Number	Circuit Number / Phase	D.C. Number	Tap Pole Number	Originator	
					Route To:	
					Responsibility	Last Name
Location / Subdivision Description:					Team Leader (C,M&S)	
Location of Failure: (Address, Distance from Transformer. Etc.):					File (LOA):	
					cc:Engineering Supervisor	

Circuit Information					Additional Information			
Voltage	Size (AWG or KCM)	Cable Section (Pad/Pole# to Pad#)	Length of Cable (FT.)	Year Cable Installed	Minutes of Thumping to Locate Fault	Riser Pole MOV Arrester In-Service (Yes / No)	Arrester at Open Point (Yes / No)	Concentric Neutral Corrosion (Yes / No)

Customer Information			
Residential, Commercial or Industrial	Transformer KVA	Loop or Radial Feed	Customer Description:

1. TYPE OF FAILED CIRCUIT (10 3-WIRE, 30 4-WIRE, ETC.): ____
2. CABLE CONSTRUCTION:
   - ☐ TRIPLEX, CONCENTRIC,15KV ☐ TRIPLEX, CONCENTRIC,JACKETED,15KV
   - ☐ SINGLE COND. CONCENTRIC,15KV ☐ SINGLE COND. CONCENTRIC,JACKETED,15KV
   - ☐ POWER, 15KV ☐ POWER, 69KV ☐ POWER, 5KV ☐ POWER, 34KV
   - OTHER: ____
3. TYPE OF INSTALLATION: ☐ DIRECT BURIED ☐ METALLIC CONDUIT ☐ MANHOLE ☐ NON-METALLIC CONDUIT
4. IF CONCENTRIC CABLE, INDICATE CONDITION OF CONCENTRIC NEUTRAL:
   ☐ INTACT ☐ PARTIALLY CORRODED AWAY ☐ COMPLETELY CORRODED AWAY
5. IF CONCENTRIC CABLE, IS CONCENTRIC NEUTRAL TINNED? ☐ YES ☐ NO
6. DESCRIPTION OF SURROUNDING EARTH (CHECK AS MANY AS NECESSARY):
   ☐ WET ☐ DRY ☐ SAND ☐ CLAY ☐ ROCKY ☐ SWAMPY ☐ OTHER
7. TYPE OF FAILURE :
   ☐ SPLICE ☐ DIG IN ☐ INSULATION FAULTED
   POSSIBLE REASON FOR FAILURE AND GENERAL COMMENTS: ____
8. DESCRIPTION OF REPAIR MADE (2 SPLICES AND 3 FEET OF CABLE ETC.): ____

NORTHERN INDIANA PUBLIC SERVICE COMPANY

Figure 20 Cable Failure Report Form

15 Evaluate Other Available Data on Installed Underground Cable

The use of historical records forms a basis for understanding the present condition of the underground cable system and identifies potential areas for future consideration. NIPSCO has logged the installed and retired assets of underground cable in a mainframe database system. The records were intended for asset records and not for purposes of relating to outage or fault data. Therefore, this data can be studied for its historical value of type of cable installed, and miles of cable installed per year etc.

15.1 Underground Cable History (age and quantities)

The data contained in this mainframe database system was called the Electric Distribution Facilities (EDFS) application, and represented Historical Asset information about the cable installed between 2 points. This underground cable history data retrieved from our database system was in the form of a text file in the format illustrated below.

```
                                       DRF
                 CNDUCR  DSTR      CNDUCR    PRCNDUCR     PRCNDUCR  PRCNDUCR  PRCNDUCR    PRCNDUCR  CNDUCR  CNDUCR
DPT  CIR          TYP    RFRNC      PNT        INST         SPAN      SPAN      RMVL        CNDU      SZ      KND
CD   NUM           CD     ID         ID         DT          VAL       CNT        DT          CD       CD       CD
---  -------  ------  --------  --------  ----------  --------  --------  ----------  --------  ------  ------
010  1042     UC      P1775010  P2411010  05/05/1987       220         1  -           N         2       AL
```

Figure 21

This data was imported into a relational database so that queries and reports could be made from the data. The underground primary cable data imported for this purpose was 32,434 records. The critical fields each record included are: a code for the Local Operating Area, the circuit number, conductor type, device ID on one end of the cable, device ID on the other end of the cable, installed date, length, and conductor size. Unfortunately, as the underground system grew, the data entry was adapted to only keep track of the asset, and did not contain sufficient fields to relate the data directly to other key information like the tap pole. Therefore, this data was used as secondary information to support the other records.

15.2 NIPSCO Outage Restoration System (NORS)

For the purpose of this data table, when an Outage occurs, and calls from customers get entered into NORS, a device category is assigned. NORS makes recommendations to a possible source of the outage, based on additional calls that come in. The 4 possible categories are DEV_CAT =:

1) CUSTOMER – assigned by NORS with only one call, with service from one transformer
2) SERVICE TRANSFORMER - assigned by NORS with two or more calls with service from one transformer.
3) DEVICE - assigned by NORS with three or more calls with service from three different transformers, or more than 50% of the customers.
4) SOURCE - assigned by NORS when additional data suggests it is a substation outage.

In order to start evaluation of cable faults, we review the data which comes from records using the "Underground Primary Fault Code". However, because this code is assigned by the operator upon closing the outage record for a given outage number, the DEV_CAT assigned by NORS during the course of the event may not provide information in this database which would better locate the area of the primary underground fault. Therefore, we will use several sources of data to validate an underground fault location. And for the purposes of this priority listing, we will only consider data that provides either a tap pole location to underground conductor, or a padmount transformer, etc.

As a result of this query, 504 records were extracted into a table "NORS_SourceOutages". This table was linked through a query using the outage source as the relationship to other tables, like; facility mapping tables, cable installation record tables, cable fault form tables, and Local Operation Area (LOA) priority listings that will be used to help prioritize our sites.

15.3 Local Operating Area (LOA) Priority

Each NIPSCO LOA was asked to submit a list of 10 areas they deem the greatest priority in electric distribution underground infrastructure improvement. Each list was submitted in a variety of formats and in a typical fashion, using local names to identify the area, instead of a tap pole or other source. Once all the lists were submitted, a second request was made to revise the list to include tap poles so that the locations could be tied to our GIS mapping system. Once all the additional data was gathered, it was translated into a table format so that the data could be related to the other tables of information.

16 Conduct Power Cable Reliability Audit

The next step in improving the electric underground infrastructure was to analyze the existing system configuration and using the data gathered, perform a reliability audit, which in part, recommends condition assessment surveys (partial discharge testing), and results analysis, with resultant recommendation proposals, and a final recommended reliability improvement program. A reliability audit covers the first critical step necessary to conduct a comprehensive underground cable reliability program. By soliciting a Cable Reliability Audit by an independent company, the audit will clarify and reinforce good practices and assumptions, and also dispel any assumptions that do not contribute to the improvement of the reliability of NIPSCO's underground medium voltage cable system by means of a cost effective method to prioritization system rehabilitation.

16.1 IMCORP Power Cable Reliability Outline

IMCORP[2] was chosen to recommend a comprehensive underground power cable reliability pilot program for NIPSCO, to help NIPSCO achieve their cable reliability goals. This process involves an IMCORP developed 5 step implementation process, which their experience has shown, helps utilities achieve their cable reliability goals. "**The goal of the process is to: Dramatically improve the reliability of our client's underground medium voltage cable systems by using historical data and a condition assessment survey to assist in the development of a proactive repair, replacement, and deferment plan in the most cost effective means possible.**"

The following outline includes the recommended 5 steps and their associated tasks:

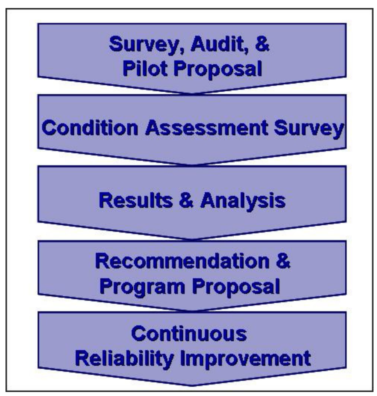


Figure 22

Step 1. Survey, Reliability Audit & Proposal

a. Perform stakeholder survey

b. Hold stakeholder meeting

c. Establish executive sponsorship

d. Perform a reliability audit

e. Select a target population

f. Analyze cost benefit

[2] IMCORP is a leader in underground cable reliability consulting and diagnostics. www.imcorptech.com

g. Develop proposal

Step 2. Condition Assessment Survey

a. Define team

b. Schedule survey

c. Optimize logistics

d. Perform conditional assessment survey

Step 3. Results & Analysis

a. Compile results

b. Perform autopsy validation

c. Perform Pareto analysis

Step 4. Recommendation & Proposal

a. Prioritize actions

b. Estimate reliability improvement

c. Analyze cost benefit

d. Build program proposal

Step 5. Continuous Reliability Improvement

a. Define team

b. Develop process

c. Implement program

d. Maintain metrics

e. Assure reliability

17 IMCORP Power Cable Reliability -Survey

The following represents the details of Step 1, Survey, Audit & Proposal.

17.1 Stakeholder Survey

Interview the customer to identify the key individuals (stakeholders) who are responsible for cable reliability and will participate in the reliability improvement activities. Once the stakeholders are identified, they are interviewed to obtain the necessary reliability audit and cost data as outlined below.

1. Scope and goal of the cable reliability effort
2. Cost benefit required for a reliability program to be considered
3. Final budget approval
4. Historical budget allocation–capital and O&M
5. Regulatory concerns and implications
6. Operation logistics and switching strategy
7. Accounting and financing considerations
8. Underground system reliability history and physical data
9. Responsibility for cable replacement activities
10. Risk assessment and reliability engineering
11. Repair, replacement, and testing standards
12. Replacement cable system design
13. Costs related to repair, replacement, and failure –penalty, lost revenue

17.2 Stakeholder Meeting

Once the stakeholders were identified, IMCORP initiated a meeting of the team members who represent the core activities of the reliability program. IMCORP worked with the NIPSCO team to develop executive sponsorship and determine the scope of the program, and reliability and economic goals.

17.3 Establish Executive Sponsorship

Make sure executive leadership goals are well defined in the scope and fully support the process as it moves forward.

17.4 Reliability Audit

IMCORP conducted a reliability audit by collecting all known historical and physical data, conducting interviews with key stakeholders, and corroborating information. The audit included the following outline:

1. Operations knowledge base
   a. Engage key operations personnel through interviews
   b. Gather perspective on reliability trends
   c. Collect Anecdotal evidence and case studies
2. Reliability indices
   a. Review historical records
   b. Analyze current data
   c. Perform Pareto analysis
3. Failure data
   a. Review Historical records
   b. Current data
   c. Correlate data and pare to analysis

18 NIPSCO Cable System Audit Results

During the years from 1985 to 1990, NIPSCO changed their cable standards to the latest technology. Unjacketed cable with cross-linked polyethylene (XPLE) insulation was replaced with jacketed cable with tree retardant XLPE or (TRXLPE) and strand filled conductor.

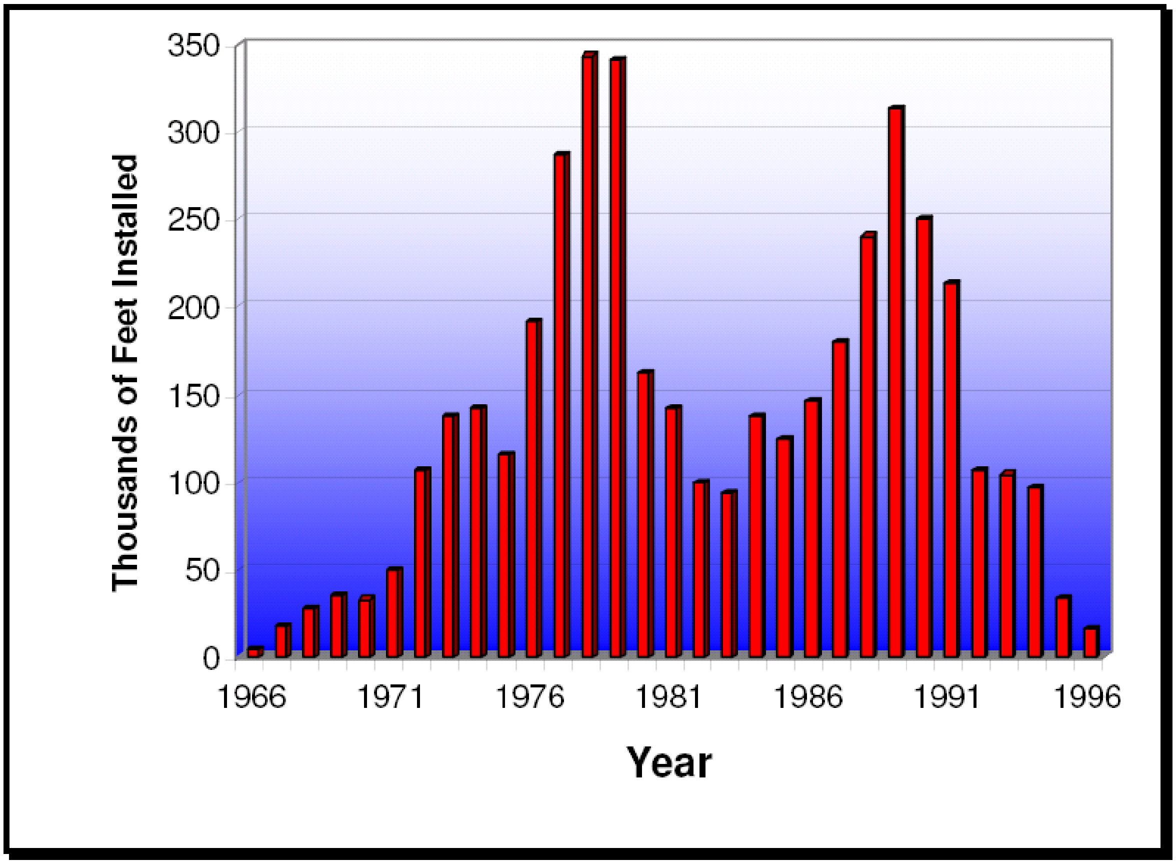


Figure 23 Length of Unjacketed Cable Installed per Year

By the end of 2005, NIPSCO had installed 1961 miles of underground cable. Of the total, 705 miles of unjacketed cable were installed by the end of 1990.

18.1 Present and Future Reliability

Although anecdotal evidence from Local Operating Areas abounds, it is important to establish statistically significant data to show failure trends. Three questions need to be answered. 1. What is the overall failure rate of the system? 2. Is the failure rate increasing, decreasing, or staying the same? 3. What is the failure rate likely to look like in a few years?

To explore the answers to these questions the NORS data covering the last 5 years was assessed. NORS tracked 491 outages from the beginning of 2001 through the end of 2005. According to this data, the failure rate is increasing by an average of approximately 11% per year.

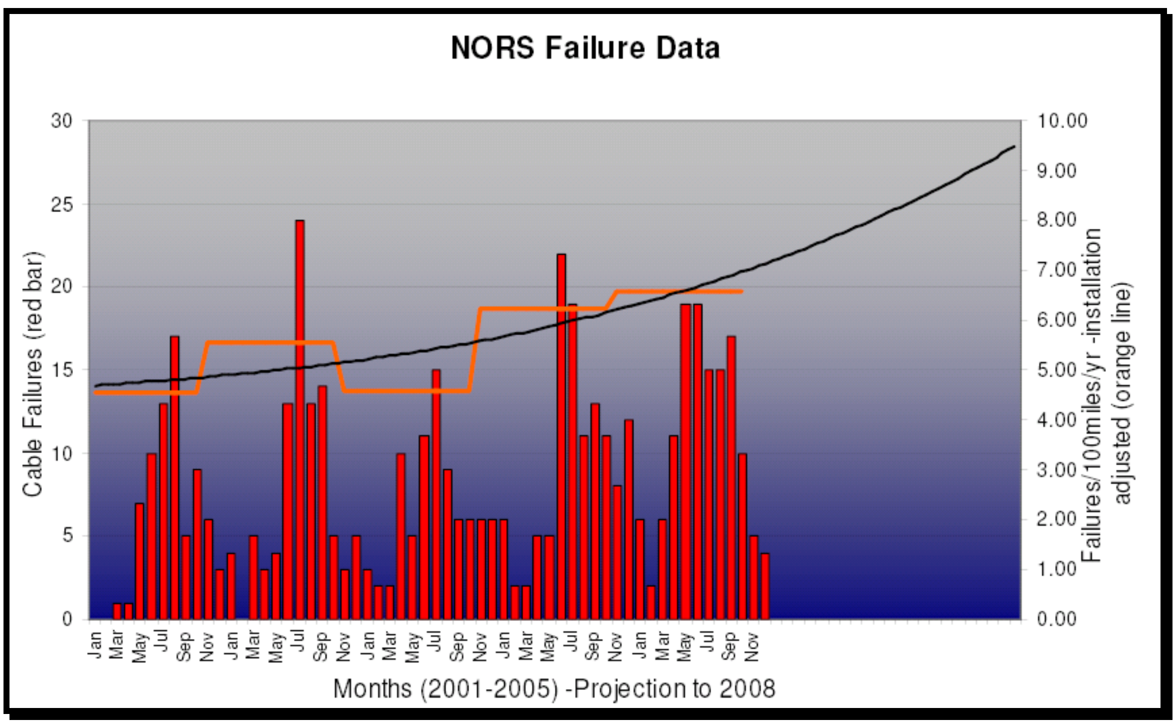


Figure 24 Failures per month is plotted with the red bars and the yearly increase shown by the orange line.

The graph shows that NORS tracked nearly 7 failures/100 miles/year in 2005. This is 13% above the national average of 6.2 failures/100 miles/year as reported by AEIC in 1994. However, a 5 utility survey on the basis of data presented at the 2004 Fall IEEE PES ICC Meeting shows that the NIPSCO failure rate is 23% lower than the 9.0 failures/100 miles/year average.

18.2 Composition of NIPSCO System

To understand the composition of the NIPSCO system, the EDFS assets database was used to generate the following pie chart of installed cable length by conductor type.

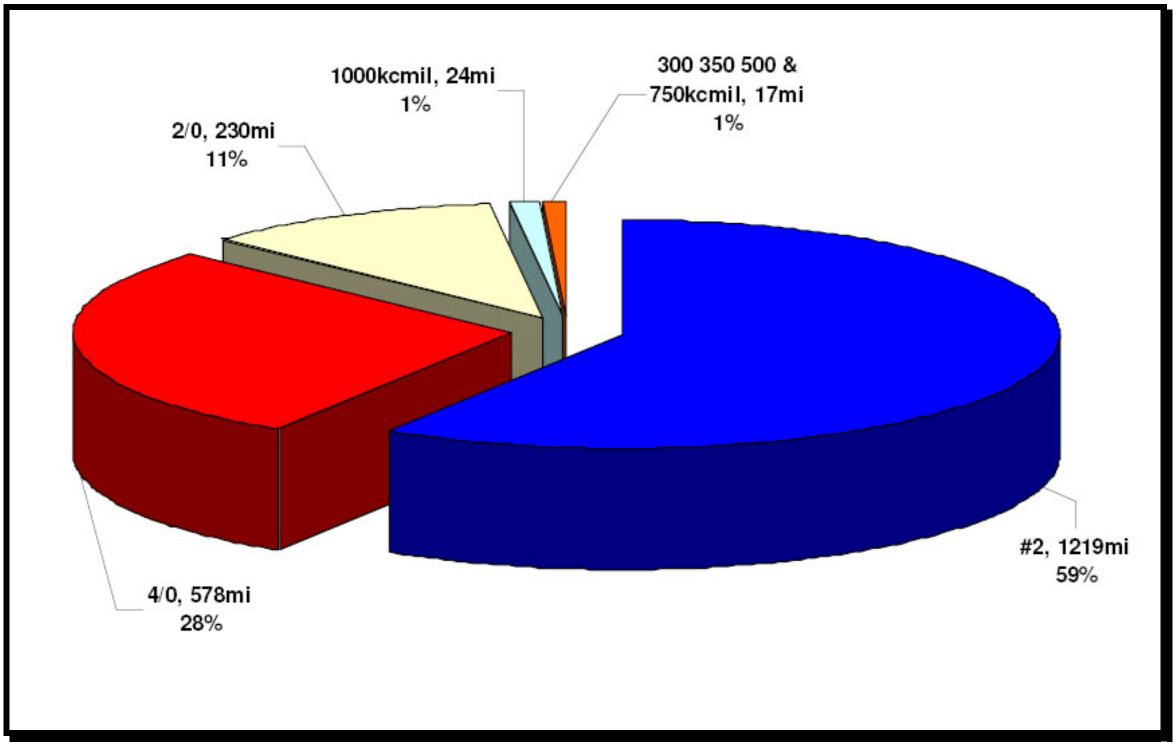


Figure 25 Percentage Installed Cable by Conductor Type (March 2006)

18.3 Failures by Cable Characteristic

To determine what type of cables failed during the 2001 to 2005 time period, 491 failures recorded by NORS were compared to the Fault Records database. 217 of the Fault Records database entries which corresponded with the NORS data had cable type information. To draw any further conclusions an assumption needed to be made. If the 217 entries of the Fault Records database are a random sampling of the 491 failures recorded by NORS, then the following graph is a statistically significant presentation of the relationship between the failures and cable type.

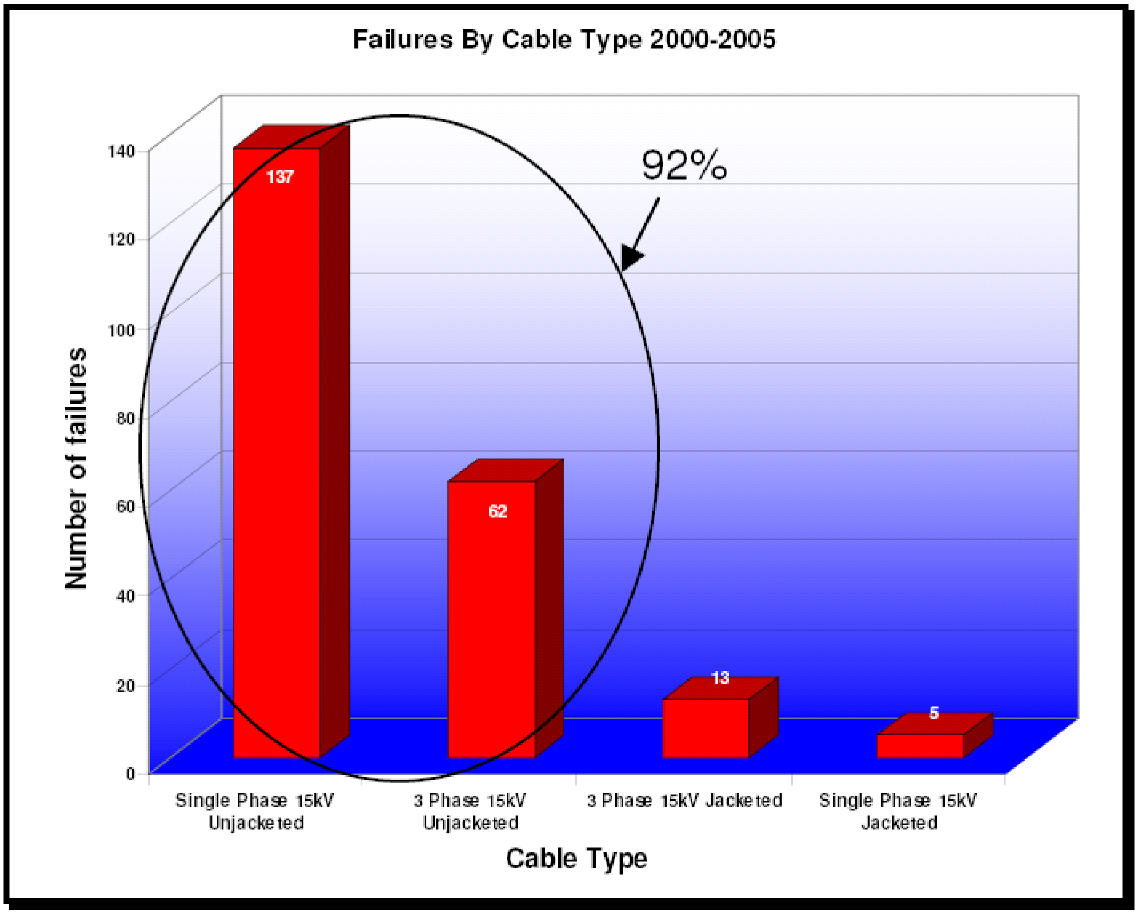


Figure 26
NORS Failure Data 2001-2005 by Cable Type

The above graph indicates that 92% of the failures are emanating from the 15kV class unjacketed cable. The EDFS asset database indicates that 95% of the unjacketed cable, about 705 miles, was installed between 1970 and 1990. This means that 35% of the cable system is causing 92% of the failures.

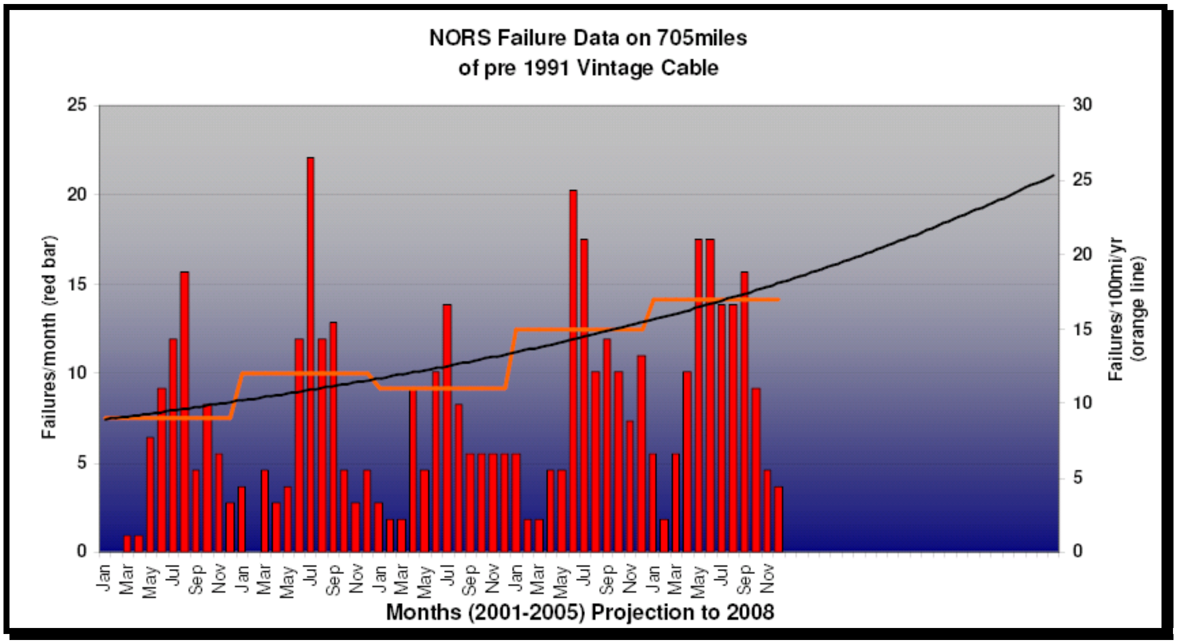


Figure 27
NORS Failure Data on 705 miles of pre-1991 Unjacketed Cable

Comparing 92% of the failures caused by 705 miles unjacketed cable to the failures recorded by NORS from 2001 to 2005, the above graph is derived. The failure rate of the 705 miles of unjacketed cable in 2005 was 17 failures/100 miles/year, or nearly 3 times the national average for URD systems reported by the AEIC in 1994 (6.2 failures/100 miles/year) and nearly 2 times the 2004 ICC survey (9 failures/100 miles/year) mentioned above. Since 2001, the failure rate has been increasing by an average of 18% per year.

18.4 Determine Target Population of Cables to be Tested

Figure 28
Google Earth Overlay of LOAs with 90% of Failures from 2001-2005

NIPSCO has nearly 2,000 miles of underground cables that are currently failing at a rate of approximately 7 failures/100 miles/year which is 13% above the national average of 6.2 failures/100 miles/year as reported by AEIC in 1994. The failure of the entire population is increasing at a rate of 11% per year. However, on a closer look at the data, 95% of the failures are occurring within the 705 miles of unjacketed cable installed prior to 1991 which is only 35% of the entire population. The 705 miles of unjacketed cable is currently failing at a rate of 17 failures/100 miles/year and may be expected to increase at a rate of 18% per year. NIPSCO's current cable replacement budget can not keep pace with the increase in the failure rate.

One of the outcomes of conducting the reliability audit was to select preliminary candidate populations. In general, the scope of the program was generally defined to include aged URD cable (>20 years old). However, newer installations with high failure rates were also considered.

This project was further refined to include a statistically significant population of unjacketed cable installed from the 1960s to the late 1980s. An estimate of approximately 600 URD cable sections would be identified to have a sufficiently large sample. Although 3 phase feeder cable sections are a small percentage of the population, they have a large impact on reliability. Feeder cable sections would be included in the project on an impact priority basis.

As shown in Figure 28, a goal is to focus on the Hammond, Crown Point, Gary, and Valparaiso local operating areas. According to NORS, these 4 LOAs have sustained 90% of the failures on 114 circuits in the last 5 years and have the highest percentage of target unjacketed cable population.

Other steps to consider in the target population are to focus on the circuits with the highest percentage of unjacketed cable. Develop a list of cable sections from the 4 LOAs to be included in this project condition assessment survey. Include the LOA priorities whenever prudent. Focus on the cable sections with the highest number of failures. Customer Average Duration Index (CAIDI) and other reliability indices will not be especially helpful in the selection process, as NIPSCO's underground system is much smaller than their overhead system.

19 Prioritize Underground Distribution Improvement Potential Sites

Within a target population area (cables that have already faulted), a key to prioritizing these sites are testing methods which lead to the identification, and ranking of typical defects found in operating cables of a given year or manufacture. When sufficient samples of cables are tested for these defects, a characterization is made about the defects potential to cause a fault. Using this information in combination with historical fault data, a priority can be created that will rank sites with a greatest potential for future faults. These cables would be candidates for improvement. However, as time moves on, other sites will also move up the priority as they too would eventually be a candidate for cable improvement.

Listed below are prioritizing factors to consider in ranking potential sites of underground distribution improvement.

19.1 Prioritizing factors

19.1.1 Cable History (outage history)

_ Vintage

_ Number of failures

_ Outage duration

_ Load (kVA) affected

_ Neighboring cable history

_ Neutral corrosion

19.1.2 Cable Physical Features

_ Insulation type

_ Conductor size

_ Jacket –Yes or No

_ Manufacturer – if known

_ Neutral type

19.1.3 Customer Considerations

_ Number of Customers affected

_ Importance to customer- hospital, government…

_ Type: residential, commercial, gov. …

_ Number of complaints

_ Safety e.g. stray voltage from corroded neutrals

19.1.4 Cost Considerations

_ Cost of replacement (high or low)

_ Economy of scale –loop/half loop replacement

_ Annual reactive restoration expenditures

_ Cost of outage –planned vs. unplanned

19.1.5 System Features

_ Cable insulation type

_ Design practices –standards

_ Workmanship/training program

_ Loading practices/ seasonal load

_ Loop or radial installation

_ Effective lighting arrestors –yes or no

_ Frequency and magnitude of voltage transients

_ Conduit, duct, directly buried

20 Summary – Define Selection Criteria, Prioritize Potential Sites

20.1 Selection of Candidate Populations (Cable Sections)

The project has selected a majority of unjacketed cable installed from the 1960s to the late 1980s. Approximately 600 URD (Underground Residential Distribution) cable sections are selected to ensure a statistically significant population.

20.1.1 Hammond, Crown Point, Gary, and Valparaiso Local Operating Areas

The Focus of the project was on the Hammond, Crown Point, Gary, and Valparaiso local operating areas. These 4 LOAs have sustained 90% of the failures on 114 circuits in the last 5 years of data and have the highest percentage of target unjacketed cable population.

20.2 Final Selection of Target Population

Using the program scope and results of the reliability audit and cost benefit analysis as a guide, the selection of the cable target population is finalized and is listed below. The area descriptions, along with LOA names, source and circuit numbers are incorporated into the list.

Selection	LOA Name	Description	Source	Circuit
1.01	Gary	Broadway and 90th Street	00805542	12-436
1.02	Gary	Broadway and 89th Street	00902217	12-436
1.02	Gary	Broadway and 89th Street	00902218	12-436
1.02	Gary	Broadway and 89th Street	00902219	12-436

Selection	LOA Name	Description	Source	Circuit
1.03	Crown Point	West 97th Lane and US 41	00807467	12-618
1.03	Crown Point	West 97th Lane and US 41	00812649	12-618
1.04	Hammond	Griffith Industrial Park	00105647	12-576
1.04	Hammond	Griffith Industrial Park	00054420	12-576
1.05	Hammond	Tanglewood Apts, 167th and Indianapolis Blvd	00095523	12-736
1.05	Hammond	Tanglewood Apts, 167th and Indianapolis Blvd	00082579	12-736
1.05	Hammond	Tanglewood Apts, 167th and Indianapolis Blvd	00082576	12-736
1.05	Hammond	Tanglewood Apts, 167th and Indianapolis Blvd	00044902	12-736
1.05	Hammond	Tanglewood Apts, 167th and Indianapolis Blvd	00044903	12-736
1.06	Hammond	Sherwood Lake Apartments	00082630	12-175
1.06	Hammond	Sherwood Lake Apartments	00082588	12-175
1.06	Hammond	Sherwood Lake Apartments	00094401	12-175
1.06	Hammond	Sherwood Lake Apartments	00085262	12-175
1.06	Hammond	Sherwood Lake Apartments	00075004	12-175
1.06	Hammond	Sherwood Lake Apartments	00082587	12-175
1.06	Hammond	Sherwood Lake Apartments	00081896	12-175
1.06	Hammond	Sherwood Lake Apartments	00084845	12-175
1.07	Hammond	Fran-Lin Parkway and Chestnut Lane, Munster	00105113	12-331
1.08	Hammond	Munster, White Oak Ave and Somerset Dr.	00082250	12-329
2.01	Laporte	Michigan City-Indian Springs	00228806	12-104
2.01	Laporte	Michigan City-Indian Springs	00226573	12-104
2.01	Laporte	Michigan City-Indian Springs	00227322	12-104
2.02	Valparaiso	Valparaiso-Shorewood North	00852506	12-598
2.02	Valparaiso	Valparaiso-Shorewood North	00852925	12-598
2.03	Valparaiso	Valparaiso-Heritage Valley South	00444564	1214
2.03	Valparaiso	Valparaiso-Heritage Valley South	01005201	1214
2.05	Valparaiso	Valparaiso-Shorewood South	01005432	12-427
2.06	Valparaiso	Valparaiso-Heritage Valley North	01002761	1279
2.06	Valparaiso	Valparaiso-Heritage Valley North	00441807	1279
2.06	Valparaiso	Valparaiso-Heritage Valley North	00444563	1279
2.06	Valparaiso	Valparaiso-Heritage Valley North	01001896	1279
2.06	Valparaiso	Valparaiso-Heritage Valley North	00445686	1279
2.07	Hammond	Dyer-Heritage Estates	00066240	12-249
2.07	Hammond	Dyer-Heritage Estates	00066240	12-249
2.07	Hammond	Dyer-Heritage Estates	00083392	12-249
2.07	Hammond	Dyer-Heritage Estates	00084819	12-249
2.07	Hammond	Dyer-Heritage Estates	00054282	12-249
2.08	Hammond	Dyer-Castlewood	00103338	12-655

Selection	LOA Name	Description	Source	Circuit
2.08	Hammond	Dyer-Castlewood	00095321	12-267
2.08	Hammond	Dyer-Castlewood	00100513	12-655
2.09	Gary	Merrillville-Southlake	00902269	12-546
2.09	Gary	Merrillville-Southlake	00902268	12-546
2.09	Gary	Merrillville-Southlake	00806533	12-546
2.09	Gary	Merrillville-Southlake	00902267	12-546
2.10	Crown Point	Hebron-Apple Valley	00805472	12-422
2.10	Crown Point	Hebron-Apple Valley	00374798	12-583
2.11	Crown Point	Lowell-Fairways	00821656	12-583
3.01	Hammond	Dyer-Heritage Estates	00066460	12-249
3.01	Hammond	Dyer-Heritage Estates	00146788	12-249
3.01	Hammond	Dyer-Heritage Estates	00069844	12-249
3.01	Hammond	Dyer-Heritage Estates	00066239	12-249
3.01	Hammond	Dyer-Heritage Estates	00059965	12-249
3.01	Hammond	Dyer-Heritage Estates	00146787	12-249
3.01	Hammond	Dyer-Heritage Estates	00066243	12-249
3.02	Hammond	Harvest Acres	00102874	12-704
3.02	Hammond	Harvest Acres	00102875	12-704
3.02	Hammond	Harvest Acres	00102872	12-704
3.02	Hammond	Harvest Acres	00096171	12-704
3.02	Hammond	Harvest Acres	00092483	12-704
3.02	Hammond	Harvest Acres	00092482	12-704
3.02	Hammond	Harvest Acres	00092481	12-704
3.02	Hammond	Harvest Acres	00103523	12-704
3.03	Valparaiso	Pheasant Valley	00430515	12-149
3.03	Valparaiso	Pheasant Valley	00430516	12-149
3.03	Valparaiso	Pheasant Valley	00430522	12-149X14
3.03	Valparaiso	Pheasant Valley	00438050	12-149
3.03	Valparaiso	Pheasant Valley	00440942	12-149X14
3.03	Valparaiso	Pheasant Valley	00446121	12-149X14
3.03	Valparaiso	Pheasant Valley	00446718	12-149
3.04	Hammond	Harrison Heights	00082619	12-293
3.04	Hammond	Harrison Heights	00082618	12-293

21 Identify Distribution System Details

The distribution underground system under review contains those areas where outages have occurred due to primary underground faults. As the list of these problematic areas are prioritized and reviewed, it is clear that there are hundreds of miles of cable to evaluate. The scope of this projects review will focus on sections designed as a “Normally Open Loop System”.

21.1 Normally Open Loop System

A normally open loop system employs a dual source, normally open primary circuit concept. In this manner, backup service can be supplied for almost all maintenance and emergency outages. The main loop consists of two radial circuits from two sources with the interconnection point normally open, and in some cases, additional branch circuits are tapped from the main loop.

A typical loop has two taps off a main line (usually overhead distribution). The loop will have one normally open point near the middle of the loop. The normal open point is established by connecting one loadbreak elbow terminator to a parking stand rather than the transformer bushing, instead of completing the loop. During maintenance or emergency events (faulted cable), any single section of underground cable can be isolated and all customers on the loop remain in service simply by connecting or disconnecting appropriate elbow terminators.

In non emergency cases, once a section of cable is identified for evaluation, the normally open elbow location is connected completing the loop, then the elbow from each end of the identified cable section is disconnected, to isolate the cable section and create a new temporary open point. While the cable section is isolated, all the transformers (all the customers) remain connected and their service is not interrupted.

The potential reliability solutions that can be explored in a normally open loop system will allow us to capitalize on the best available options, with minimal inconvenience to the customer. They are:

1. Reduce the number of underground faults.

2. Reduce the number of customers impacted should future faults occur.

3. Reduce outage time in the event of future faults.

22 Condition Assessment Survey

In Step 2 of the process, a condition assessment survey (Partial Discharge Test) is performed and the end results identify only those sections of cable that require action like repair or replacement. Typically, less than one third of the cables tested will require full replacement. Using condition assessment survey as a basis for improvement requires the test be performed on all cable sections in order to determine the next step or plan of action. From the results of the test, solutions from cable replacement to completing underground loops can be made on each specific area, depending on the need. The following details the specifications of the Partial Discharge Diagnostics used.

22.1 Condition Assessment Survey (Partial Discharge Diagnostics)

Without specifications and guidelines to follow, a user may not be able to distinguish one form of testing from another. In this case, the condition assessment survey testing chosen for evaluation is a Partial Discharge (PD) test. However, included in this requirement was the need that the testing company have an in-depth understanding of the technology, its economic and practical impact on the utility, and have a proven experience/track record. Some companies that offer testing are offering a simple and superficial PD test without demonstrated qualifications or by means of a technology which is unsupported by recognized standards, or years of data collected from actual field experience.

"Partial discharge (PD) is an electrical discharge that does not completely bridge the space between two electrodes. When a power cable is placed under electric stress of sufficient level, partial discharge may occur at localized defect sites. These defect sites are caused by workmanship errors and/or aging and are aggravated by power system voltage transients. Defects can be found in joints, terminations, or cable insulation.

On every reel of new cable produced at the factory, a partial discharge (PD) diagnostic is routinely conducted. This is performed in an electromagnetically shielded room using a 50/60Hz voltage source. The field test, performed after installation (acceptance testing) but, before being energized is intended to ensure that the cable was not damaged during transportation, handling and installation and that the accessories have been properly installed. The field test, performed periodically thereafter, during service (maintenance testing) to determine if the cable system remains reliable. To ensure harmony, traceability and relevance, field tests must, as well, be conducted at 50/60Hz, with a measurement sensitivity which is in line with that in the factory. Noise mitigation and ensuring high sensitivity are, therefore, of utmost importance.

In service, the cable system is subjected to switching and lightning transient overvoltages which may trigger electrical treeing in defective cable systems whose partial discharge inception voltage level is exceeded by the transients. The test voltage level must ensure that defects which may be excited by these transients are identified and removed, so the cable reliability is maintained at a very high level. This diagnostic process should monitor the relative thresholds of the inception (PDIV) and extinction (PDEV). By this process the voltage and pico-Coulomb (pC) magnitude thresholds are compared to the acceptable PD levels defined by IEEE standards. Interpretation of PD test results requires a thorough knowledge of the phenomenon, coupled with a proven data driven experience base. The interpretation must be supported by an extensive data-base covering a vast array of cable systems and service conditions, obtained over long periods of testing and supported by system performance data and laboratory investigations."[3]

22.1.1 Partial Discharge Diagnostic Specifications

Partial discharge diagnostics for new and existing Cables, Joints and Terminations for extruded 5kv, 15kv, 25kv and 35kv class power cable system.

Diagnostic provider shall be independent of the supplier, manufacturer and installing contractor of the cable system.

22.1.1.1 Voltage Source:

The Diagnostic provider must use a power frequency (50/60Hz) voltage source to energize the cable exceeding nominal voltage level of the cable. The test voltage level shall be in accordance with IEEE 400.3 and comply with the requirements of the next paragraph.

[3] As stated from the IMCORP Partial Discharge Diagnostic Specification. IMCORP is a leader in underground cable reliability consulting and diagnostics. www.imcorptech.com

22.1.1.2 Non-Destructive:

It is crucial to monitor the response of the cable to a voltage stress that is gradually increased from zero to the highest transient voltage which may be experienced by the cable system in its particular environment without being above nominal voltage for more than 15 seconds.

22.1.1.3 Experience:

Diagnostic provider shall have at least 10 years experience utilizing the methodology described herein in the electrical partial discharge testing of power cables with database to support expert knowledge based algorithms and recommendations.

22.1.1.4 Noise Mitigation:

Diagnostic provider must have robust digital noise mitigation algorithms to achieve a sensitivity in all conditions that is in the range of ICEA and IEEE cable and accessory standards.

22.1.1.5 PD Excitation:

The cable under test shall be excited by a power frequency voltage source levels from 1.5 times nominal voltage and up to 3.0 times nominal voltage (voltage levels are agreed upon with customer) to monitor the cable in transient conditions experienced during switching, lightning, etc. The relative thresholds of PD inception voltages (PDIV) and extinction voltage (PDEV) shall be identified to be compared to IEEE standards.

22.1.1.6 Measurements:

The PD measurements shall include PD phase information which is used to characterize the PD type and relative threshold levels. The PD response of the cable shall be recorded at voltage levels that can be compared to IEEE thresholds or acceptable levels agreed on by customer.

22.1.1.7 Calibration:

Diagnostic instruments shall be calibrated in accordance with NETA, IEEE, ICEA, or other nationally recognized organizations and standards.

22.1.1.8 Sensitivity:

The Diagnostic must specify an acceptable sensitivity measurement method and achieve a sensitivity level commensurate with that prescribe ICEA for factory testing.

22.1.1.9 Qualified:

Convincing evidence must be provided that diagnostic testing is conducted by qualified individuals, supported by registered professional engineers.

22.1.2 Partial Discharge Testing Criteria

- Disconnect and test each cable (out of service) using external, variable voltage power frequency source to replicate normal operation and provide a voltage level equivalent to the transients expected on the system under test.

- Diagnostic testing shall include the following four steps:

    - Map the cable using a Low Voltage TDR (time-domain reflectometry) to locate joints, terminations and cable anomalies

    - Sensitivity assessment is to ensure that the test sensitivity is as close as possible to the 5 pico-Coulombs (pC) level stipulated by ICEA for extruded cables. No diagnostic test shall be deemed reliable if sensitivity levels of 50pC and 100pC cannot be met for cables and accessories, respectively.

    - Diagnostic stress simulation test with time varying, power frequency excitation voltage applied.

    - Data analysis, interpretation and recommendations to include locations of partial discharges, severity assessment and corrective actions.

- Maximum test voltage used shall be 1.5-3.0 times the operating voltage (Uo) of the cable (line–to-ground) depending on the cable's voltage class. An example for 35kV class new extruded cable would be to record response data at 1.0, 1.3, 1.5, 1.7, and 2.0Uo levels.

- Provide summarized reports showing cable length, locations of joints, terminations, and defect sites, PD inception voltage levels, severity assessment and recommendations for future action.

IEEE Standard Thresholds

- IEEE 48-1996 Terminations No PD ≥ 5pC up to 1.5Uo

- IEEE 404-2000 Joints No PD ≥ 3pC up to 1.5Uo

- IEEE 386-1995 Separable Connectors No PD ≥ 3pC up to 1.3Uo

- ICEA S-93-639-2000 MV Extruded Cable No PD ≥ 5pC up to 4Uo

Definitions:

Inception Voltage: The voltage at which PD first appears is the Inception Voltage (PDIV)

Extinction Voltage: The PD is extinguished when the voltage is reduced below the level called the Extinction Voltage (PDEV)

Pico-Coulomb: a measure of charge used to in defining the magnitude of a PD.

22.1.3 IEEE 400-2001 - Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems

Based on the IEEE standards as guidelines, "if the cable system can be tested in the field to show that its partial discharge level is comparable with that obtained in the factory tests on the cable and accessories, it is the most convincing evidence that the cable system is in excellent condition". Therefore, any cable that passes IEEE 400 should not need to be replaced, regardless of it's age, or the history of any of the same vintage cable. Reliability will improve by only replacing the unreliable cable in lieu of traditional replacement of all the cable of a given vintage or manufacture.

22.1.3.1 Example Partial Test Report – Unreliable Cable vs. Reliable Cable

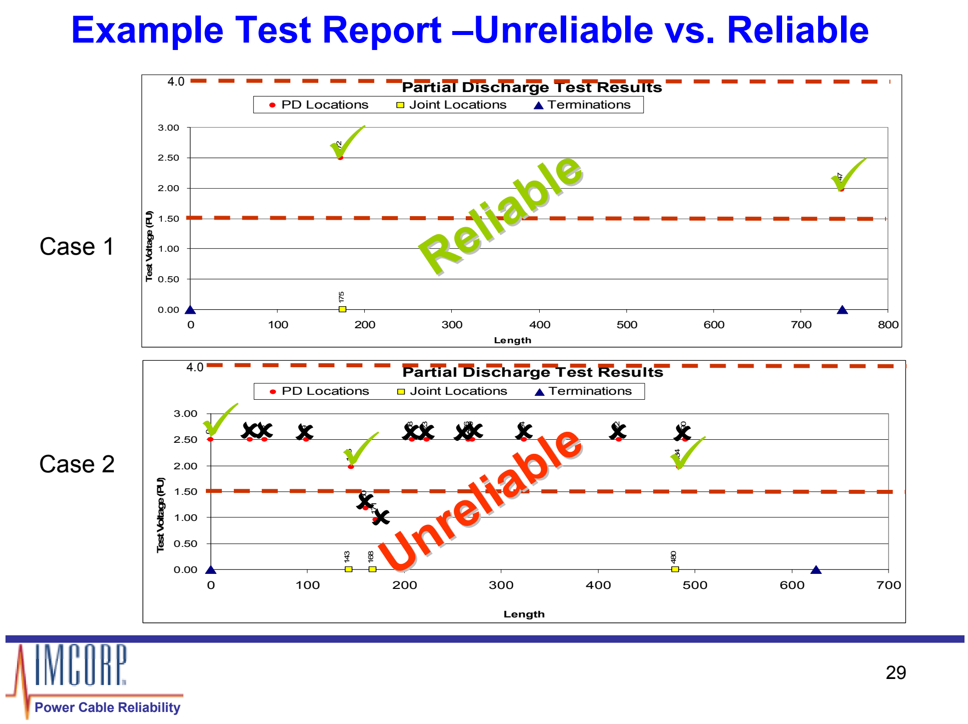


Figure 29

22.1.3.2 Typical Partial Discharge Producing Defects

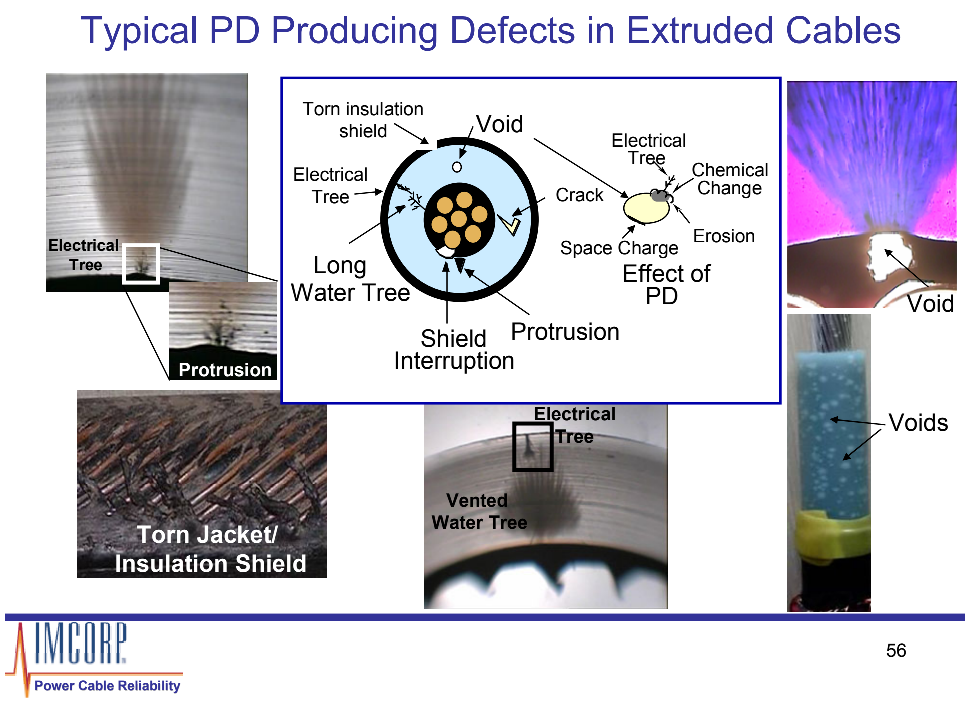


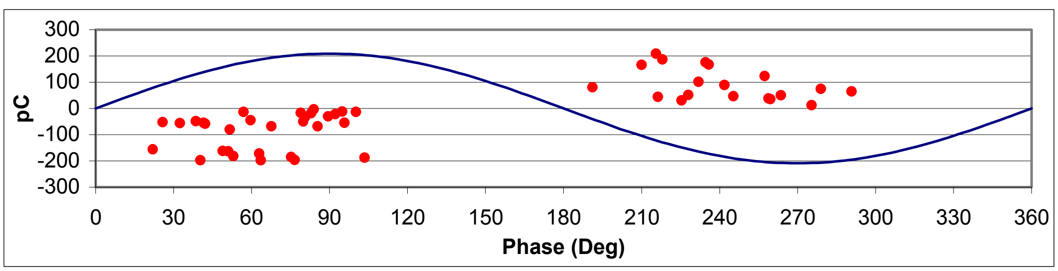
Figure 30

23 Process Documentation and Practices – Condition Assessment Survey (PD testing)

23.1 Process Documentation of Partial Discharge Diagnostics

Documentation is created for each of the IMCORP Diagnostic Survey Tests. The individual reports provide test results along with detailed information on each cable segment and phase. Information and recommendations from each report are condensed into a summary that better enables the client to prioritize repairs and build a working reliability program. The IMCORP PD diagnostic survey process produces a wealth of information which needs to be condensed and organized into actionable information.

49 PDs from near end: 0.0ft, 89.0pC, at 18.0kV



51 PDs from near end: 0.0ft, 85.0pC, at 18.1kV

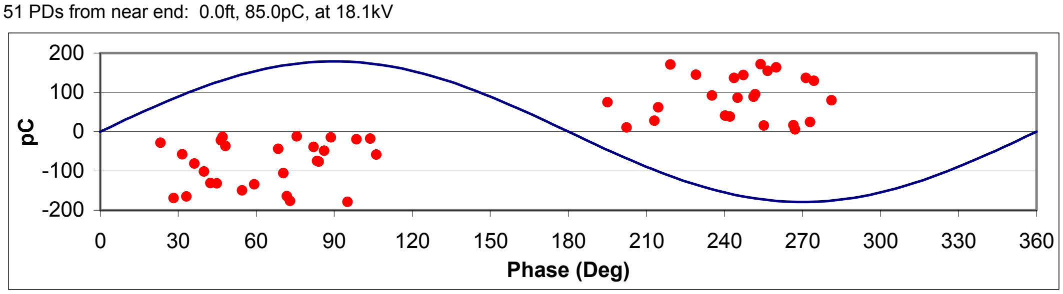


Figure 31 Partial Discharge Detail

The detail in figure 31 above is an example of an information level reviewed by the IMCORP, and in this case, the partial discharges are from the end termination and are mitigated in the field. This level of detail is included in the customer documentation.

The first level of reporting is the detailed diagnostic report. This report is generated by the IMCORP diagnostic software and presents a simplified profile of each cable segment (Figure 32) and the severity of each PD site located.

IMCORP www.imcorptech.com

Partial Discharge Test Results

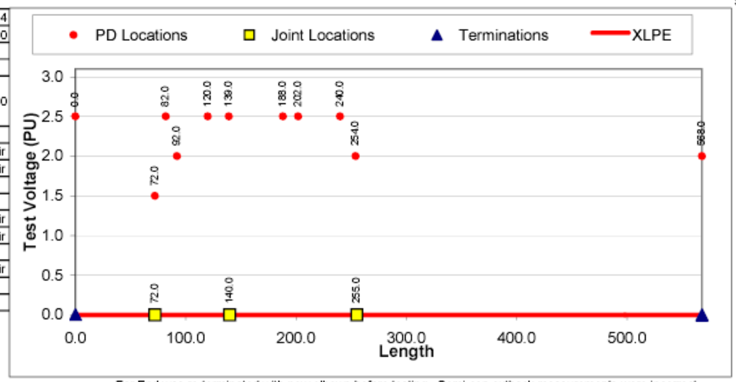
Project ID	280906_1428_12 436_805542_P3915150_P0848150		
Project For	NIPSCO	**Circuit**	12 436
Tested On	9/27/2006	**Source**	805542
Project Team	Keary Maloney	**From**	P3915150
	Monte Hiatt	**To**	P0848150
		Cable Year	Unknown
Operating Voltage	**7.2 kV**	**Cable Class**	15kV

Phase A
Length (ft) 568.0
PDIV

Test Voltage (kV)	7.2	8.6	9.4	10.8	14.4
PU	1.0	1.2	1.3	1.5	2.0
Test Voltage (kV)	18.0	18.1	18.2		
PU	2.5	2.5	2.5		

Sensitivity (pC) < 5 pC **Pulse Speed** 500.0

Discharge Type	**Location**	**pC**	**#/Cycle**	**Test kV**	**Recommend**
Splice	72.0	22	35	10.8	Monitor
Cable	92.0	44	31	14.4	Immediate Repair
Cable	254.0	14	229	14.4	Immediate Repair
FE Termination	568.0	9	2	14.4	Monitor
NE Termination	0.0	84	7	18.0	Monitor
Cable	82.0	19	34	18.0	Immediate Repair
Cable	120.0	20	9	18.0	Immediate Repair
Splice	139.0	64	5	18.0	Monitor
Cable	188.0	20	27	18.0	Immediate Repair
Cable	202.0	19	9	18.0	Schedule Repair
Cable	240.0	9	8	18.0	Schedule Repair



Splices
72.0
140.0
255.0

Comments: Far End was re-terminated with new elbows before testing. Semi-con cutback measurements were incorrect. Recommend repairing cable section between splices 72ft and 255ft, if practical and cost effective. Considering the length of the cable, it may be more realistic to replace the section.

Figure 32 Simplified Profile of Cable Segment with recommendation

This report is then reviewed by the IMCORP project manger assigned to the program. After reviewing the individual report the IMCORP project manager updates the project summary document with the detailed report findings and makes the appropriate recommendations on the entire segment. The recommendation will be determined by a rule set agreed upon by the customer and IMCORP. This report is created for each cable section evaluated.

23.2 Typical Field Practices of Partial Discharge Diagnostics

The following outline describes details to switch and prepare cable segments.

1. Each segment (single-phase or three-phase) to be tested will need to be switched out of service before it is tested.
    a. The cable grounds must remain connected.
    b. The tested cable segment needs to be electrically isolated and grounded.
    c. Termination preparation
        i. Elbows
            1. Far end elbow(s) need to be cleaned, re-greased, and parked on a parking bushing(s) or appropriate adapter.
            2. Near end elbow(s) need to be cleaned, re-greased, and the appropriate adapter connected to the test equipment.
        ii. Live Front Terminations
            1. Terminations need to be unbolted and cleaned
            2. Terminations need to be isolated for grounds
            3. The near end termination needs to be connected to test equipment

d. Testing :

i. Customer assist crew starts by selecting a point in the circuit where one or more cables can be tested without having to shift the location of test truck.

ii. Assist crew prepares the first cable before the arrival of IMCORP crew.

iii. As the first cable is tested the assist crew is preparing a second cable

iv. As the second cable is being tested, the first cable will be reassembled and the next cable is being prepared.

v. The assist crew moves to a second location on the circuit where one or more cables can be tested.

vi. The process is repeated from step (ii).

Figure 33 Typical Equipment Setup

24 Condition Assessment Survey (Initial Verification)

One of the early goals of the Condition Assessment Survey was to verify that the technology would be capable of not only determining if a cable needed to be replaced, but if the defects detected were actually there and could be verified in a dissection analysis.

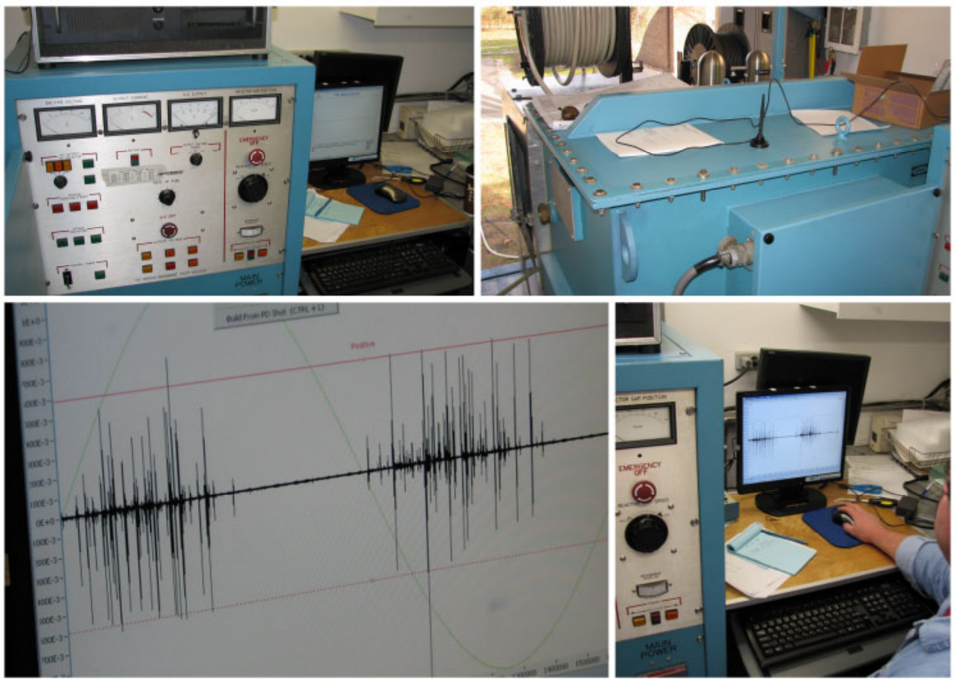


Figure 34 Testing in Progress

In our first testing area, an opportunity developed whereby a section of cable was determined to have a severe defect and the defect occurred in an area that excavation would cause minimal customer impact. The following pages outline the process of defect removal and analysis to verify the technology.

The cable parallel to Connecticut Dr was tested for partial discharge activity and location. As the 60Hz voltage was increased to simulate voltage transients, a partial discharge site was located very close to nominal voltage of the cable. As a result, the defect was located using a location matching system and removed by NIPSCO crews. The sample was sent to the IMCORP sample laboratory and dissected, finding several defects, the most significant being the electrical tree the source of the PD (see Figure 35 and 36).

24.1 Dissection Analysis

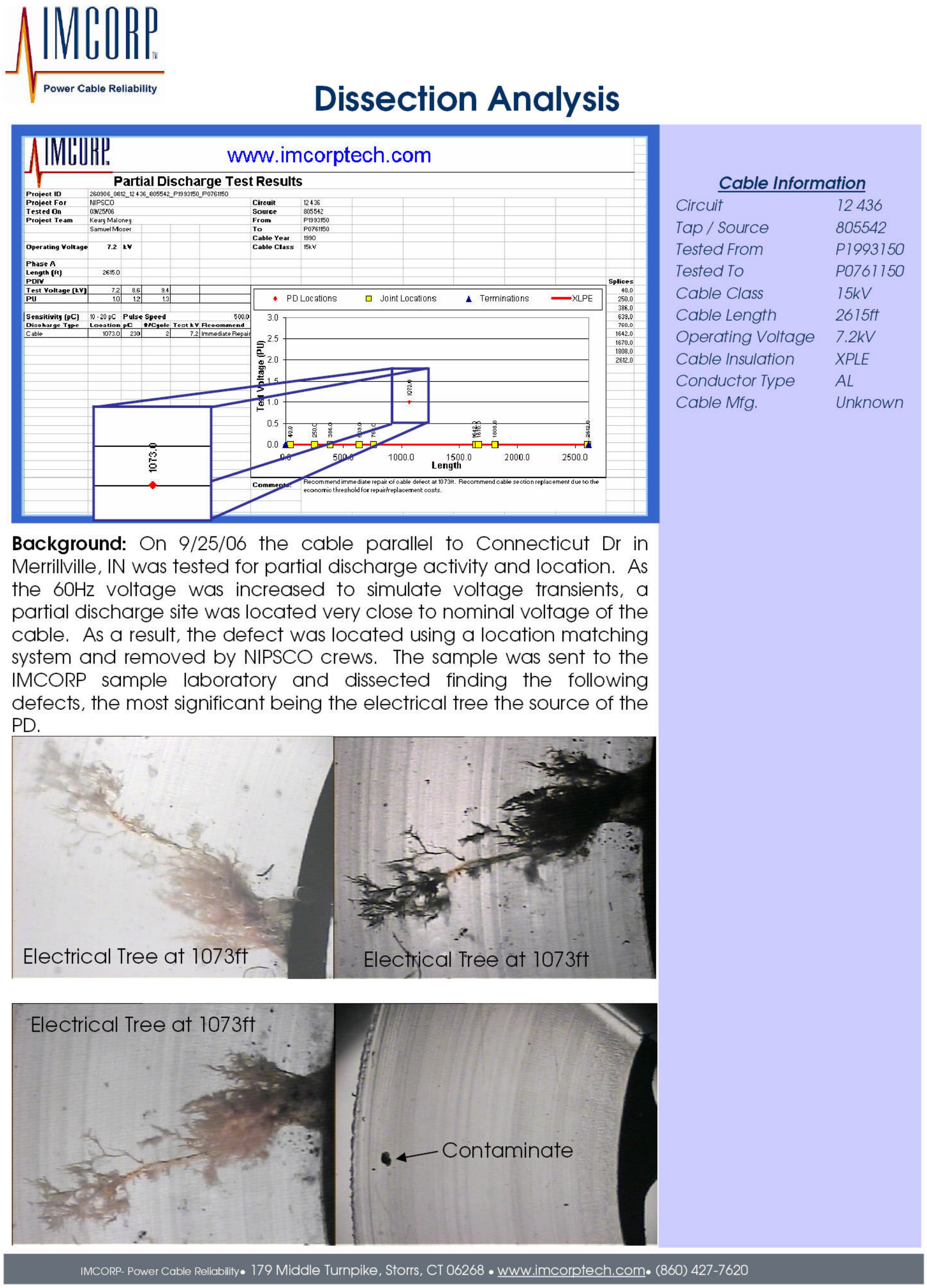


Figure 35 Dissection Analysis Report

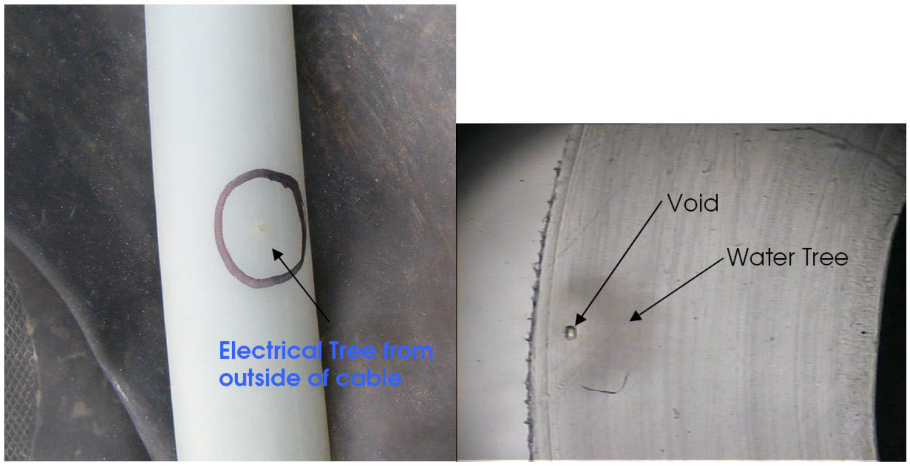


Figure 36 Additional Electrical Tree Example

Since this was near the start of the Condition Assessment Survey, early dissection analysis was helpful to relate the technology and reports to the actual defect that is detected and in this case, removed.

25 Continued Condition Assessment Survey (PD testing)

The IMCORP Diagnostic Survey Testing was continued in each of the identified areas. The individual reports provided test results along with detailed information on each cable segment and phase. Information and recommendations from each report are condensed into a summary in spreadsheet format that better enable the client to prioritize repairs and build a working reliability program.

25.1 Example of Data Contained in Summary Report Recommendation

The following example illustrates some of the comments that the summary report would contain.

Circuit: 12 249

Source: 00054282

From: P1039010 **To:** P1065010 **Test Date:** 6/5/2007

Recommendation: SCHEDULE REPLACEMENT

Age: 1977 **Length:** 255

Description A Phase: Far end termination discharge at 14.4kV. Cabe PDs 76ft ad 141ft at 18kV. Recommend scheduling cable section replacement due to the economic threshold for repair/replacement B Phase: Cable PD 61ft and far end terminatin discharge at 14.4kV. Cable PD 146ft at 18kV. Recommend scheduling cable section replacement due to the economic threshold for repair/replacement C Phase: Near end termination discharge at 9.4kV. Cable PDs 66ft, 96ft, 109ft, 58ft, 68ft, 89ft, 103ft, 121ft and 131ft. At 18kV. Recommend scheduling cable section replacement due to the economic threshold for repair/replacement

File Reference: 050607_1029_12 249_00054282_P1039010_P1065010.xls

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26 Cable Replacement

26.1 Description of Cable Replacement Selection

The goal of condition assessment survey (Partial Discharge testing combined with detailed analysis and recommendation) is to assist in the development of a proactive repair and replacement plan in the most cost effective means possible.

The result of the condition assessment determines if the cable should be replaced immediately or can wait to be scheduled. In addition, if there is only one defect in 300 feet of cable (for example), then a cable repair consisting of cutting out the defect and replacing it with a short piece of cable is the most effective solution. And finally, if the condition assessment surveys results in a cable that has passed the tests, then a recommendation of "defer" is made, which means that no action should be required for up to 10 years.

A cable system is given the label 'Replace' when the number of severe defects to be repaired has exceeded an agreed upon economic threshold which clearly indicates that the repair investment will not be sufficiently lower than the net worth of the system asset. Based on this assessment, the maps are created identifying which cable sections need to be replaced. Each cable section is replaced using typical installation practices outlined below.

26.2 Cable Replacement Practices in a Normally Open Loop System

A normally open loop system employs a dual source, normally open primary circuit concept. In this manner, backup service can be supplied for almost all maintenance and emergency outages. The main loop consists of two radial circuits from two sources with the interconnection point normally open, and in some cases, additional branch circuits are tapped from the main loop.

A typical loop has two taps off a main line (usually overhead distribution). The loop will have one normally open point near the middle of the loop. The normal open point is established by connecting one loadbreak elbow terminator to a parking stand rather than the transformer bushing, instead of completing the loop. During cable replacement, any single section of underground cable can be isolated and all customers on the loop remain in service simply by connecting or disconnecting appropriate elbow terminators.

In cable replacement cases, once a section of cable is identified for replacement, a new conduit is installed between the 2 ends using typical damage prevention guidelines of trenchless technology.

Once new cable is pulled in the conduit and excavated externally to the end locations, additional company safety rules are implemented in switching and working near live conductors. The normally open elbow location is connected, completing the loop, then the elbows from each end of the identified cable section is disconnected, to isolate the cable section and create a new temporary open point.

While the cable section is isolated, all the transformers (all the customers) remain connected and their service is not interrupted. The new cable is routed in place of the old cable and new terminations are made on the new cable and the old cable is retired from service. Finally, the new temporary open point is re-connected to the loop, and the original normally open elbow location is disconnected and the circuit is returned to normal.

26.2.1 Sectionalizing Underground Cable

In a given underground circuit, physical requirements of cable replacement sometimes do not permit cable replacement of one for one. In some cases, cable that runs from point A to point B in the original direct burial installation cannot be replaced with one direct path. When the path of the new cable is complicated, additional termination points need to be installed to facilitate cable replacement installation. These additional new termination points “sectionalize” or divide a cable into sections to help in troubleshooting, which breaks up areas into smaller sections with fewer customers. The equipment that is installed is routinely referred to as sectionalizing cabinets or sectionalizing pedestals.

26.3 Cable Repair and Replacement Activities

The final step in improving the electric underground infrastructure is to take action on the results of the condition assessment survey (Partial Discharge Test). In this case, the number one action item to improve reliability is to repair or replace cable that has been identified. Having been tested and determined in need of action, only repair or replacement will restore the reliability to the electric underground infrastructure and avoid future faults. In the original scope of this project, the list below outlines the areas where the first improvements were made based on the recommendations of the condition assessment survey. Most of the cable is in existing established developments and neighborhoods, and the technique of underground guided boring was used to install most of the new cable. In addition to cable terminators and splices, pedestals used to sectionalize circuits were also installed as needed to facilitate replacement.

The area descriptions below represent the areas of cable replacement for this report.

Selection	LOA Name	Description	Circuit
1.01	Gary	Broadway and 90th Street	12-436
1.02	Gary	Broadway and 89th Street	12-436
1.03	Crown Point	West 97th Lane and US 41	12-618
2.01	Laporte	Michigan City-Indian Springs	12-104

27 Distribution Summary - Conclusions

The distribution underground system analysis incorporated a thorough review of problematic areas that needed improvements. This review incorporated the findings of Circuit Reliability Testing that created a proactive work plan to systematically target areas for improvement by factual data from definitive results and analysis.

The anticipated result was that near 1/3 of the target areas for improvement would need cable replacement and that the benefit of proactive cable replacement would maximize our ability to reduce the number of future underground faults. The implementation of the recommended solutions was anticipated to have a positive impact on the reliability of the system as well as the restoration time should an outage occur. These results were also anticipated to be a catalyst to embark on a long-term electric underground infrastructure improvement program.

27.1 Circuit Reliability Testing - Conclusions

The Circuit Reliability Testing was performed on 576 cable sections, which is in the range that was targeted for this project. It was anticipated that approximately 1/3 of the cables may need replacement, but even this number is a far greater number of Circuit Sections than our yearly budgeted dollars for Cable Replacement would allow. However, the percentage of cable to replace was a major part of the project scope, which is to compare an anticipated recommended replacement rate to the actual recommended replacement rate. This replacement rate will help establish a future testing rate that matches budgeted cable replacement dollars. In order to do this comparison, a significant statistical population was recommended to be tested. This population was decided to be near 600 cable sections that were in most need of improved reliability.

Circuit Reliability Testing creates a proactive work plan to systematically target areas for improvement by factual data from definitive results and analysis. Budgeted dollars are put where they are most needed.

27.1.1 Selection of Candidate Populations (Cable Sections)

The project selected a majority of unjacketed cable installed from the 1960s to the late 1980s. Approximately 600 URD (Underground Residential Distribution) cable sections were selected to ensure a statistically significant population. The focus of the project was on the Hammond, Crown Point, Gary, and Valparaiso local operating areas. These 4 LOAs have sustained 90% of the failures on 114 circuits in recent years of data and have the highest percentage of target unjacketed cable population.

Using the program scope and results of the reliability audit and cost benefit analysis as a guide, the selection of the cable target population was finalized and tested.

27.1.2 Anticipated Results of Circuit Reliability Testing

The original analysis and proposal by IMCORP provided an estimate and analysis for Single Phase and Three Phase cable. Since the three phase percentages were the same, only the single phase will be summarized in the following:

Single Phase Analysis

Condition assessment data: (typical data percentages)

No. of cable sections 1,000

No. of cable sections to defer action 556 (55%)

No. of cable sections to repair 297 (30%)

No. of cable sections to replace 147 (15%)

Percent of cables deferred (defer + repair) 85%

27.1.3 Actual Results of Circuit Reliability Testing

After testing, an analysis of the data for Single Phase and Three Phase cable is combined and summarized as follows:

Single and Three Phase Analysis

Condition assessment data: (actual data percentages)

No. of cable sections 576

No. of cable sections to defer action 350 (60.8%)

No. of cable sections to repair 123 (21.4%)

No. of cable sections to replace 103 (17.8%)

Percent of cables deferred (defer + repair) 82.2%

27.1.3.1 Comparison of Actual vs. Anticipated Results of Circuit Reliability Testing

Comparisons of the Actual vs. Anticipated results were favorable. To a great degree, the percentages of cable sections in each category were near prediction, with only a 2.8% greater number of cables needing replacement than predicted. Therefore, the anticipated savings and other estimates are expected to fall in line.

Single and Three Phase Analysis

Condition assessment data: (actual data percentages)

	Actual	Anticipated
No. of cable sections	576	1,000
No. of cable sections to defer action	350 (60.8%)	556 (55%)
No. of cable sections to repair	123 (21.4%)	297 (30%)
No. of cable sections to replace	103 (17.8%)	147 (15%)
Percent of cables deferred (defer + repair)	82.2%	85%

27.1.3.2 Detail Summary of Circuit Reliability Testing by LOA Area

The following summary shows the breakdown of recommendations for each of the LOAs tested. As a result of Circuit Reliability Testing, we have discovered that we will need to budget for replacement, approximately 20 cable sections, out of each 100 sections that are tested.

Recommendation	% of Sections	Total Selection	Crown Point	Gary	Hammond	Laporte	Valparaiso
IMMEDIATE REPLACEMENT	5.2%	30	5	2	6	1	16
SCHEDULE REPLACEMENT	12.7%	73	7	6	36	2	22
Total Replacement	**17.8%**	**103**	**12**	**8**	**42**	**3**	**38**
IMMEDIATE REPAIR	4.2%	24			16		8
SCHEDULE REPAIR	17.2%	99	8	18	56	2	15
Total Repair	**21.4%**	**123**	**8**	**18**	**72**	**2**	**23**
INSPECT	1.6%	9	1	1	1		6
RETEST	0.3%	2	1	1			
DEFER ACTION	58.9%	339	13	35	189	6	96
Total Defer	**60.8%**	**350**	**15**	**37**	**190**	**6**	**102**
Total Tested		**576**	**35**	**63**	**304**	**11**	**163**

27.2 Cable Replacement – Conclusions

Having been tested and determined to be in need of action, only the repair or the replacement of the cable will restore the reliability to the electric underground infrastructure and avoid future faults, thus having a positive impact on the reliability of the system. Previous approaches to underground improvement were limited to reacting to outages or performing wholesale replacement of cable, which limits the areas that could be addressed with the budgeted dollars.

27.2.1 Anticipated Findings on Cable Replacement

A cable system is given the label ‘Replace’ when the number of severe defects to be repaired has exceeded an agreed upon economic threshold which clearly indicates that the repair investment will not be sufficiently lower than the net worth of the system asset. Based on this assessment, the maps are created identifying which cable sections need to be replaced. Each cable section is replaced using typical installation practices. This cable replacement and repair makes long-term upgrades to system assets in the most cost effective manor.

27.2.2 Actual Findings on Cable Replacement and Repair

27.2.2.1 Replacement Findings

The label ‘Replace’ was used when the number of severe defects to be repaired has exceeded an agreed upon economic threshold which clearly indicates that the repair investment will not be sufficiently lower than the net worth of the system asset. There were 2 subcategories for replacement; immediate replacement and scheduled replacement. Our findings were that most of the replacements became scheduled replacements due to the fact that the resources needed for replacement were unique and equipment and crews for this needed to be scheduled. However, immediate replacements did tend to get scheduled first whenever possible.

The results of the testing also became a catalyst to embark on a long-term electric underground infrastructure improvement program. Using the remaining data of cable that was tested, a long-term program was outlined to improve the underground infrastructure at NIPSCO. Since the number of cables identified outran a single years budgeted dollars, cable repair or replace findings continue to be validated as some of those sections identified exhibit faults before they get scheduled for replacement. It is recommended that the testing rate keep pace with the anticipated replacement statistics, and be replaced as soon as the budget allows, and within a year if possible.

27.2.2.2 Repair Findings

The label "Repair" was less straight forward than the replace label. Although our guidelines were based on 2 repairs in 300 feet of cable, a decision to repair or replace these sections required more engineering evaluation. In some cases, cables identified as repair were instead replaced because of the staging of the crews to replace adjacent cable sections. Also, other site conditions such as fences, sheds, driveways etc., - would prevent a repair of the designated location.

There was a short evaluation of an IMCORP cable matching technique to help locate the exact location of a repair site. This technique is described as follows:

Once a defect or failure site has been located by the IMCORP Estimator system or other fault location set, the Matcher is used to locate the physical location of the site. To locate a site the user takes the estimated location from one end of the cable and, using a measuring wheel, wheels out the cable path to the estimated location. The cable is exposed and a transmitter is attached to the shield power cable. On one end of the cable a receiver is connected. The receiver computes the location of the transmitter and the actual location value is compared with the estimated value form the diagnostic or fault location test. If there is a difference between the estimated value and location of the transmitter the actual location of the defect or fault is exactly the difference of these two measurements away.

Although the technology was effective, the cost of using an experienced technician or keeping an in house technician skilled at using the matching technique was beyond the scope of this project. It is estimated this technique would be most cost effective on longer runs of cable (at least twice our system average length of 325 feet) with only 1 or 2 defects, since this would indicate that the repair investment would be sufficiently lower than the net worth of the system asset (replacement of the cable).

In most cases, if the repair was near one end of the cable, the repair was to splice a section of cable from beyond the defect area, to its nearest end. In the case of a 300 foot piece of cable, a defect would typically need to be within 100 feet of the end to warrant a repair; otherwise it would just be replaced.

27.3 Sectionalizing Underground Cable – Conclusions

Each area under test was already primarily in a loop configuration. This project installed sectionalizing pedestals as well as fused sectionalizing pedestals (a fuse senses the fault condition and operates to open and sectionalize the circuit). These pedestals were installed mostly in three phase loop applications. The three phase sectionalizing pedestals were installed when the original direct burial installation could not be replaced with one direct path, or its path was reconfigured to a better functional layout. Single phase fused sectionalizing pedestals were installed when there were single phase taps to transformers etc, from a three phase loop circuit. In this way, a fault on a single phase circuit would be limited to the single phase loads, and the three phase loads would remain energized.

We have found that when our direct buried cable installations are replaced, the new conduit installations usually require some sectionalizing pedestals to accommodate the new configuration. The exact need for sectionalizing pedestals will not become evident until engineering is done with estimating the project.

27.4 Other Findings

After the critical repair and replace cable sections have been addressed, another option to improve reliability is to complete the loop in an underground circuit. If a section is a radial feed (only fed from one direction) then reliability will suffer because the one section must be repaired before all the customers beyond the failure on that radial section have power. Completing the loop reduces the number of customers affected for the longer duration outage, and will allow power to be restored in a shorter amount of time. Due to priority of the problematic areas, only areas that already had a majority of the components tied in a cable circuit loop were considered for this project and therefore, no additional cable circuit loops were created as part of this project.

Lastly, an option for infrastructure improvement considered for this project was the use of Faulted Circuit Indicators, to help restore power in a shorter amount of time. However, it was decided that long term solutions (like cable testing and replacement) were a better permanent solution vs. Faulted Circuit Indicators, which improve restoration time but still require a more permanent solution for the cable to be addressed in the future. Faulted Circuit Indicators were felt to be valuable as a tool, for use in areas that had not yet been tested, but had just begun to have cable faults. In this way, the ability to locate, isolate the faulted section, and restore service would be improved until such time as cable testing and cable replacement could be implemented.

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This report is about a work effort where the overall objectives were to establish a methodology and approach for selected transmission and distribution (T&D) grid modernization; monitor the results; and report on the findings, recommendations, and lessons learned. The work reported addressed T&D problems and solutions, related reliability issues, equipment and operation upgrades, and respective field testing.

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