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Medium Voltage Underground Cable White Paper

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Nuclear Energy Institute

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EXECUTIVE SUMMARY

The Nuclear Energy Institute (NEI) offers the attached White Paper for your information concerning the NRC concerns related to potential common-mode failure of medium voltage underground cables. These concerns were expressed in a letter dated February 05, 2004. A public meeting was held in June 2004 to discuss the staff concerns and review available information. Following this meeting, NEI agreed to consider the concerns. After consultation with our industry representatives, we decided that there was benefit in developing the attached White Paper.

In December 2004, Nuclear Energy Institute (NEI) formed a Medium Voltage Underground (MVU) Cable Task Force to address the performance questions. Following a meeting in January 2005, an industry survey was prepared to collect data concerning MVU cable installations, manufacturing types, failure modes, and cable replacement attribute data, if failures had occurred.

As a result of the survey, a more complete understanding as to the extent of the cable issue was developed. A large segment of the installed MVU cables throughout the industry have not experienced any problems at all. While several nuclear sites experienced some cable degradation and failures due to specific cable designs and manufacturing types, virtually all were corrected by cable replacement.

The purpose of this White Paper is to address the potential aging issues involved with MVU cables, review cable construction, design improvements made over the years, and document actual operating histories based on a comprehensive survey of installed MVU cables.

The Task Force analysis of the Survey results led to a recommended approach for the management of cable aging. In addition, this White Paper identifies transition issues to be considered by plants renewing their operating licenses.

MVU cables that experience prolonged, wet conditions may have degraded insulation, based upon the insulation material. Thus, some MVU cables are more susceptible to the effects of voltage surges, such as lightning, that can lead to failure. Increased care during installation and the use of modern cable insulation have resolved the historic troubles. NEI Survey evaluations conclude that MVU cable failures are random and are not a common-mode failure. Thus, we do not believe that there is a generic regulatory concern that needs to be addressed.

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1 OVERVIEW

1.1 BACKGROUND

Medium voltage cables used in nuclear power plants were expected to have very long lives, at least the 40 years of the initial licensed period. The manufacturers and non-nuclear-power users of medium voltage cable have since recognized that cables manufactured during the 1970s did not always meet service life expectations. By the mid-1980s, the industry identified a number of improvements – such as insulation reformulation, improved cleanliness to reduce impurities, tighter quality control, and improved manufacturing methods – which were incorporated into cables manufacturing. Fortunately for the nuclear industry, even though problems existed with cable design and manufacture, the voltage stresses in nuclear plant applications are relatively low compared to the cable rating, in most cases.

Early nuclear plant cables were constructed with black or brown ethylene propylene rubber (EPR) or cross-linked polyethylene (XLPE) insulation, although a few plants used natural or butyl rubber-insulated cables. In dry applications, these cables have very long service lives. If the MVU cables are both energized and continuously wet, especially with the presence of significant manufacturing flaws, service lives of less than 40 years can be expected for some cable designs. Cables are now produced with higher quality extrusion practices, improved cleanliness, and better materials which reduce the probability of contaminants and voids, and leads to longer service lives. Contaminants and voids are a significant problem in wetted extruded cable insulations because they disturb the potential gradient within the insulation and increase the potential across the remaining good insulation.

For XLPE, the water-enhanced degradation takes the form of water-treeing in which the potential gradient gradually forces the water to create small channels in the polymer that look like trees under magnification. The exact mechanism of water-enhanced degradation of EPR is less understood and more difficult to observe due to the opacity of the material. Different types of EPR are in use; EPR sub-types have different susceptibilities to water-enhanced degradation. Pink (red) EPR, which is now used in most EPR medium voltage cable designs, has treated clay fillers to preclude water absorption that makes the insulation less prone to water-enhanced degradation than black EPR. Brown EPR cables were purposely designed to have small leakage currents through the insulation to prevent charge buildup. This design prevents charge buildup to the point where water-enhanced degradation can occur.

This water-enhanced degradation does not cause direct breakdown of the XLPE or EPR insulation, but rather reduces the dielectric strength of the insulation, eventually weakening the material to the point where it is susceptible to voltage surges that can initiate partial discharging. Partial discharging causes relatively rapid electrical degradation, leading to an electric tree and a faulted condition in weeks to months. Instantaneous failure in the weakened condition would only be expected under severe lightning surge conditions. Most nuclear plant medium voltage circuits are not directly exposed to lightning strike conditions, given that the cables are either inside buildings or underground and not terminated to equipment exposed to direct lightning strikes.

1.2 SUMMARY OF CONCERNS

1.2.1 NRC Information Notice 2002-12

On March 21, 2002, the NRC issued Information Notice 2002-12, Submerged Safety-Related Electrical Cables. It discussed failures at:

- Oyster Creek (4160v Anaconda Unishield),
- Pilgrim (cable submerged in manhole filled with water),
- Brunswick (cable underwater and various material condition issues), and
- Davis-Besse (isolated component cooling water cable fault and broken PVC conduit).

In addition to raising the issue, the staff began to look at other plants for similar issues. After additional inspections and finding what they believe to be a significant list of failures, the staff then sent the letter [Reference 1] to NEI to address whether or not a common mode failure existed. The staff also attempted to arrive at risk-informed insights about the frequency of overall core damage implying it might be significantly degraded as a result of multiple failures of medium voltage cables. During the NRC public meeting on June 2, 2004, the staff presented the results of a risk-informed analysis of failure of medium voltage underground cable. The risk analysis assumed failure of all wet circuits as a starting point. The degradation mechanism does not lead to immediate simultaneous failure under any condition, making total loss of all wet underground cables upon re-energization in a Loss of Coolant Accident (LOCA) scenario extremely unlikely.

1.2.2 NRC Perception of "Dilemma"

During the NRC public meeting on June 2, 2004, the staff cited what was termed a "regulatory dilemma." Plants undergoing license renewal have agreed to a cable-testing program after 40 years of plant life, but non-license renewal plants were not committed to any testing. The NRC's opinion was that cables are failing at lifetimes shorter than 40 years.

Analysis of the NEI MVU Cable Survey has shown that nuclear utilities are responsive to cable failures. Contrary to the NRC perception, analysis, the data indicates that the failures do not appear to be age related; the failures appear to be more attributable to manufacturers' defects that take time to manifest.

1.2.3 Industry Response and Capabilities

Nuclear utilities have been responsive to cable failures. Redundancy of the plant electrical and operating systems has precluded cable failures from causing shutdowns, loss of capacity, or loss of safety function.

Having equipment out of service due to cable failures could count against system availability indicators. Thus, it is in the best interest of the utility to restore the cable to service as quickly as possible, to analyze the cause of the cable failure, and ensure that the resolution is a permanent fix. The NEI MVU Cable Survey data indicates that those plants with multiple cable failures have taken aggressive actions to understand and address the issues.

1.3 MVU CABLE SERVICE HISTORY

Underground routing of power cables has long been desirable for a variety of reasons: the physical protection it provides; the low ambient temperature presented to the cable and the resultant high ampacities; the large natural heat sink provided by the soil and its favorable impact on transient loading capabilities; the invisibility of network once installed, etc. Unfortunately, in most parts of the country, installation of cables underground guarantees that they will be exposed to some degree of submergence. The extent and duration of that submergence are influenced by many variables. In systems provided with adequate and well-maintained drainage, short-term submergence consistent with post-storm runoff does little more than wet the surface of the cable, given the slow diffusion of moisture through common jacketing systems. In contrast, direct-burial installations or poorly sloped and drained raceways will ultimately expose the cables to extended submergence durations, which are sufficient for moisture to penetrate common polymeric jackets.

The earliest applications in the underground network of solid dielectric cables using natural rubber insulation were plagued with moisture-induced problems. The resultant degradation assumed two forms: electrical instability and physical instability. Electrical instability in water was characterized by ever-increasing leakage current versus time with the risk of localized thermal runaway and failure of the circuit. Physical instability of the insulation system was characterized by leaching of compound constituents or significant swelling when exposed to water. Both modes of physical instability led to the development of large-scale voids and eventual failure.

In the early 1960s, HMWPE[1], XLPE, and various synthetic rubber insulations (black EPR [Reference 10][2] and black butyl [Reference 11] systems) began to be deployed in medium voltage distribution networks. With the exception of HMWPE, these same materials were used in the earliest nuclear-generating stations. A key feature of these materials was their enhanced moisture stability compared with legacy insulations. As a consequence, most distribution utilities adopted HMWPE or XPLE due to their lower dielectric losses and costs, and then routed such circuits with little concern for moisture. None of these new materials lived up to their promised moisture stability and were subsequently superseded by more robust systems.[3]

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[1] High-molecular-weight polyethylene
[2] Reference 10 describes the development of one such system and includes a brief review of the status of the full range of alternate polymers.
[3] Black EPR was replaced by gray, red, or pink EPR. HMWPE was supplanted by XLPE and XLPE was replaced by TR-XLPE (tree-retardant cross-linked polyethylene).

The moisture related failures had the greatest impact on distribution utilities, since those networks consist of numerous, very long underground medium voltage feeders serving a number of shorter low voltage circuits. In contrast, nuclear plant underground cable systems typically consist of only a few long medium voltage circuits. As a consequence, the bulk of the research to-date has been directed to understanding and resolving the moisture-driven issues that were of particular interest to the distribution market. The conclusions drawn from distribution-related research are not always directly commutable to the nuclear industry. Assessing applicability of distribution research for nuclear applications remains one of the toughest challenges for both the user and regulatory communities.

1.4 IMPACTS ON OPERATIONS

Impacts to plant operations to-date have generally been minimal, with cable replacements and cable material upgrades occurring on an as-needed basis. In general, redundancy of the plant electrical and operating systems has precluded cable failures from causing shutdowns, loss of capacity, or loss of safety function.

1.5 REGULATORY COMPLIANCE

When a cable failure occurs, utilities investigate, identify the root cause, determine the extent of condition, and repair/replace the cable. License Event Reports (LERs) are issued in accordance with 10CFR50.73,

Any cable failure that results in a non-operable status of a safety-related SSC within the Technical Specification envelope will result in a Limiting Condition for Operation (LCO) and the corresponding actions to ensure continued safe operations.

2 NRC & INDUSTRY ACTIONS

2.1 NUCLEAR REGULATORY COMMISSION

2.1.1 Staff Concerns

On February 5, 2004, Mr. J. Calvo, Chief NRR Electrical Branch sent a letter [Reference 1] to NEI concerning potential common mode failure of medium voltage underground cables. The staff identified 23 License Event Reports (LERs) and Morning Reports that documented (2 kV-15 kV) cable failures due to suspected water treeing and a reduction of dielectric strength in underground, wet, and generally inaccessible applications. The staff believed that the documented failures were only a small part of the actual number of total failures occurring, since not all failures would require this type of reporting.

The staff concern was primarily directed to the fact that many safety-related systems and components such as emergency diesel generators (EDGs) use 4.16 kV and 6.9 kV to power safety buses. They also were concerned by the failures occurring well before the end of service life (10 – 20 years rather than 40 years) and were questioning whether or not the cables were designed to operate in a submerged environment.

2.1.2 LER Database

From the LER Data Results for Medium Voltage Systems (1980 – 1994): "The LER database contained 50 reports related to medium voltage circuits. A total of 52% of these reports were related to cable, 40% to connectors, and the remainder to compression / fusion fittings and splices. Twenty-six failure reports covered medium voltage cables; none of the failure reports were maintenance-induced. The most prevalent failed sub-components were insulation (27%) and conductors (19%); 54% were unidentified. The single most common failure mode for cable was a short-circuit / grounding (27% of the 26 applicable reports); 54% of the failure reports could not be attributed to any specific cause. Two failure reports covered medium voltage cable splices, one of which was maintenance-induced. Insulation failure accounted for the remaining failure, which was caused by moisture intrusion. Due to the comparatively low number of reports for both [cables and connectors] (26 and 20, respectively) and the lack of detailed information, no real inferences regarding sub-component, mode, or cause can be postulated."

2.1.3 NUREG/CR-3122

NUREG/CR-3122 [Reference 6] "considered the effects and circumstances surrounding electrical faults of cables, connectors, and other electrical components used in both nuclear and non-nuclear facilities. . . The Nuclear Safety Information Center (NSIC) database was searched for applicable reports, and the study also examined proceedings from the Doble Clients Annual Conference . . . for pertinent data. Plant visits and interviews were also used. The study concludes that cables and connectors will have a predictably long service life if properly installed and not subject to mechanical forces, moisture or excessive temperatures. This lifetime is generally dictated by the aging of the insulation; failures of cable appear random and generally affect only segments of a cable run . . ."

2.2 DEPARTMENT OF ENERGY

2.2.1 SAND 96-0344

The SAND 96-0344 [Reference 5] thoroughly searched problem and failure data in nuclear plant databases, such as the INPO Nuclear Plant Reliability Data System (NRPDS) and License Event Reports (LERs), as well as EPRI studies such as TR-103834-Part 1. These reviews could not filter individual cable characteristics, except for differentiating between low voltage and medium voltage. In addition, cable sub-components could not always be categorized, so results were examined for more global age-related stressor trends.

2.2.2 Conclusions of SAND 96-0344

"The number of cable and termination failures during normal operating conditions (all voltage classes) that have occurred throughout the industry is extremely low in proportion to the amount of cables and terminations. . . Wetting concurrent with operating voltage stress appears to produce significant aging effects on medium voltage power cable. . . Damage to cable insulation during or prior to installation may be crucial to a cable's longevity, particularly for medium voltage systems."

2.3 INSTITUTE FOR NUCLEAR POWER OPERATIONS

2.3.1 Nuclear Plant Reliability Data System

NPRDS Results for Medium Voltage Systems (1975 – 1994) states: "A total of 41 events from 12 different nuclear units were recorded for medium voltage cable and terminations. . . For the remaining 35 reports [after 6 filtered as 'maintenance-induced'], cable failures constituted the highest single percentage (69%), followed by splices (17%), and connectors (11%). The low number of total reports is consistent with the relatively small fraction of plant cable systems operating at medium voltage levels. Due to the small amount of data, no inferences regarding medium voltage component reliability can be drawn. Of the 24 failure reports covering medium voltage field cable [after two filtered as 'maintenance-induced'], the most prevalent failed sub-component was insulation (92%). The single most common failure mode for cable was a short-circuit / grounding (62%) followed by cutting, breaking, or cracking of the insulation (21%); 54% of the failure reports could not be attributed to any specific cause. The majority of failures noted in the reports (70%) were detected during operation of the cable. Two failures were detected during maintenance and none during surveillance. Of the failures detected during operation, 79% affected the required function of the equipment; the remaining 21% had no effect on the circuit's required function. Six failure reports were applicable to cable splices. Insulation failure accounted for all six reports. All six reports included shorting to ground as the failure mode. The failure cause and method of detection showed no significant trend."

2.4 ELECTRIC POWER RESEARCH INSTITUTE

2.4.1 EPRI TR-103834

EPRI TR-103834 Part 1 [Reference 4] reported on "Effects of Moisture on the Life of [Medium Voltage] Power Plant Cables". In 1994, personnel at fossil and nuclear power plants were surveyed to determine the number and types of medium voltage cable failures and failure causes. The survey also sought feedback on any currently used cable diagnostics and whether further development of residual life evaluation techniques were required. The resulting sample from telephone interviews represented 50 plants from 24 utilities. Cable construction characteristics (the vast majority were EPR- or XLPE-insulated) and failure data were tabulated accordingly. Only 34 failures in almost 1000 plant-years of experience were identified as 'externally initiated' and were related to wetting in conjunction with manufacturing defects, damage during installation, and transient surges. Only one of the 50 plants indicated they still use DC high-potential testing for condition monitoring, but even that one exception was searching for an alternative (and less potentially destructive) cable evaluation approach. At the time of this EPRI survey (1994), there was insufficient interest and funding to support development of new condition-evaluation test methods.

2.4.2 EPRI 1003664

Recently (2003), DOE / EPRI 1003664 [Reference 7] conducted a survey to identify the specific types of medium voltage cables in service, assess failure experience with these cables and their accessories, and evaluate the techniques available for determining the condition of medium voltage cable systems. The majority of the respondents' cables were EPR-insulated and manufactured before the 1980s. The survey found that some utilities were still applying DC high-potential withstand tests, but that the practice is generally being discontinued due to potentially damaging effects on aged insulation. Other diagnostics continue to detect localized degradation by partial discharges (PDs) and to measure average condition of the insulation by dissipation factor (tan δ) or similar measurements. This EPRI/DOE Report states that further validation of results and interpretation with these developing test techniques is needed. There is much T&D experience using these PD and dissipation factor diagnostics on XLPE cables. Cable industry consensus is being documented in IEEE 400.2 and 400.3 draft guides; however, there is little experience with EPR cables. Significant work is needed to develop condition evaluation criteria for cables with all three forms / colors of EPR insulation. While this survey and study were well-planned, the response from the nuclear plant industry was less than representative, with only eight stations (14 units) participating in the EPRI/DOE survey.

2.4.3 Industry Groups

EPRI's Plant Support Engineering (PSE) operates and facilitates the EPRI Cable Program, which includes the Cable Users Group and the Cable Condition Monitoring Working Group. The Cable Condition Monitoring Working Group was formed in 1997 to guide cable condition monitoring and aging management research. In 2000, a need to more directly support plant staff responsible for cable aging management was recognized and the Cable Users Group was formed. The group provides a forum for the discussion and assessment of research, issues, and events related to cable system aging management. The focus began to shift towards medium voltage cable in 2001, with medium voltage cable a dominant topic during current meetings. During 2004, presentations covered causes of medium voltage cable failures, testing methods that are currently available, and historical and current cable polymers, and manufacturing methods. The Cable Users Group is also being used to support dissemination of the information generated by the NEI MVU Cable Task Force through presentation and discussion of industry findings.

2.5 NUCLEAR ENERGY INSTITUTE

2.5.1 NEI MVU Cable Task Force

Based on the public meeting with NRC on June 2, 2004, an NEI Medium Voltage Underground (MVU) Cable Task Force was established by the industry. The MVU Cable Task Force identified gaps in understanding of the state of the nuclear industry with respect to medium voltage underground cable and established a plan to obtain the additional information using a comprehensive industry survey.

Since a number of different types of cables are in use and each type has different aging characteristics and testability, the Task Force recognizes that understanding the nature of the cable population and the failure history by cable type is critical to the analysis of the issue and judging its importance. The MVU Cable Task Force will continue its work to document and resolve MVU cable issues.

3 MVU CABLE DESIGN

3.1 CABLE DESIGN SUMMARY

In general, nuclear plant cable systems are judged to be less susceptible to moisture-related degradation than similar systems in distribution service. This is due in large measure to their low electrical stress levels and to the use of rubber insulations, overall jackets, duct bank systems, and well-shielded terminations.

The vast literature produced in response to moisture-related degradation in the distribution arena has been assessed as a valuable resource for nuclear utilities in understanding and evaluating moisture-related degradation in XLPE insulated cables. It is less applicable to those stations that utilize rubber insulation systems.

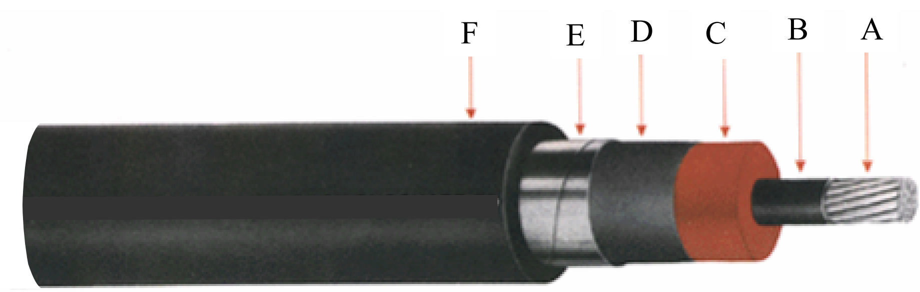
The extensive use of rubber insulation systems has also made the numerous tests developed for the distribution market of marginal value to the majority of nuclear utilities. The lack of detailed knowledge regarding the degradation mechanisms of black and non-black rubber insulations exposed to long-term immersion remains a major impediment to the development of meaningful tests for this class of cables.

3.2 CABLE CONSTRUCTION

3.2.1 Medium Voltage Cable Construction

Underground medium voltage cables at nuclear plants are installed as one of three basic cable assembly configurations: as individual insulated single conductors; as a twisted combination of the insulated single conductors known as a 'triplexed' assembly; or as a covered three-conductor cable. In any of these assemblies, the insulated conductors will share the same basic construction shown in Figure 1-1.

Figure 1-1 Shielded Single-Conductor Medium voltage Cable Design



A = conductor	B = conductor shield	C = insulation
D = insulation shield	E = metallic tape shield	F = jacket

The conductor (A) is typically stranded copper or aluminum, the former being more common in nuclear power plants. The insulation (C) is typically cross-linked polyethylene (XLPE) or ethylene propylene rubber (ERP), with the latter being more common in nuclear plants. Shields (B and D), composed of semiconducting polymer in modern designs, help maintain a uniform voltage stress in the insulation. The metallic tape shield (E) provides a continuous drain for the shield and a return path for fault currents. The jacket (F) adds mechanical protection as well as an additional barrier to moisture and external contaminants.

3.2.2 Voltage Rating

Typical distribution service feeders are rated 5 kV through 46 kV. As noted elsewhere in this paper, nuclear plant auxiliary power distribution system feeder cables are predominantly rated 5 kV with lesser amounts of 8 kV and 15 kV.

- **Susceptibility** – The combination of lower voltage rating and larger minimum conductor size (see Conductors below) means that nuclear cable systems generally operate at the lower end of the range of electrical stresses at which water treeing occurs in XLPE. Thus, such systems are less susceptible to moisture-related degradation.
- **Applicability of Literature** – Since electrical stress is one of the initiating factors for the process of water treeing and is a significant factor in the rate of propagation, the lower stresses present in nuclear plant cable systems mean that degradation onset will be later than that reflected in the literature for typical distribution designs.
- **Viability of Test Methods** – The technical viability of available cable test methodologies is not impaired by the nuclear industry's use of lower-voltage-rated cable systems.

3.2.3 Conductors

The conductor (A) is typically stranded copper or aluminum, the former being more common in nuclear power plants. The AWG or MCM cross-sectional area size, associated diameter, and number of strands are standard and unaffected by material choice. The outside surface of the conductor can be smoothed to a near-perfect circle by compacting the strands to a compact-round standard. While reducing flexibility somewhat, the compact-rounding helps to avoid potentially ionizing and discharging air gaps at the inside surface of the insulation, where the voltage gradient is greatest.

Distribution and plant conductor design philosophies differ substantially. Distribution designers frequently employ aluminum and typically use solid conductors for aluminum wires up through 2/0 AWG and copper up through 6 AWG. Stranded conductors are utilized for all larger sizes. While the solid conductor is somewhat stiffer, it does effectively block the flow of water through the interior of the cable. Water blocking of stranded conductors can be accomplished through the use of water-swellable powders or a thixotropic gel filling for the strand interstices. In contrast, nuclear plants utilize stranded copper conductors.

- **Susceptibility –** Aside from the influence of minimum conductor size on electrical stress described above, there are no significant differences in susceptibility to moisture-induced degradation between the two utility markets. Neither segment of the market utilized strand-blocking in their early designs. The bulk of the distribution market began specifying water-blocked conductors in the early 1980s.[4] By this time, plant designers had migrated to modern EPR insulations, thus obviating the need for strand-blocking in any new procurement.
- **Applicability of Literature –** The applicability of literature related to moisture-induced degradation is not influenced by the type of conductor or its construction.
- **Viability of Test Methods –** None of the existing diagnostic technologies for assessing moisture is dependent upon conductor material, construction, or strand blocking attributes.

3.2.4 Conductor Shield

To assure such vulnerable air gaps between the conductor and insulation are prevented, an effective conductor shield or a strand shield (B) is required over the conductor, regardless of whether or not the insulation itself is shielded. It is typically a thin (~10 to 20 mils) extruded semi-conductive compound compatible with the primary insulation. Like the electrodes of a capacitor, the insulation shield on the opposite side of the cable insulation and the conductor shield help to confine the electric field and create symmetrical radial distribution of voltage stress within the dielectric.

Due to limits in extrusion technology, carbon-impregnated cotton tapes were used for the conductor shield in early medium voltage cable design. With such tapes, stray fibers protruding from the conductor shield tape could become encapsulated in the insulation during extrusion. These protrusions became initiating sites for water-tree growth. The subsequent development of dual-pass and dual-tandem extrusion systems facilitated the use of polymeric conductor shields and the elimination of the inner tape. This transition was largely complete by 1970.

- **Susceptibility –** XLPE-insulated cables with tape conductor shields have a high degree of susceptibility to moisture-related degradation. Since the majority of the cable in nuclear service has extruded strand shields, the nuclear industry will be less susceptible to water-related degradation than the distribution segment of the market.
- **Applicability of Literature –** Some of the highest failure rates reflected in the literature are from the time frame when tape conductor shields were utilized with XLPE insulation. Since the bulk of cables in nuclear service have extruded conductor shields, the general failure rates cited in the distribution industry and even the specifics of the cited failure mechanism (fibrous protrusions) will not typically be applicable. The literature is silent regarding the effect of fibrous shield protrusions on rubber-insulated cable.

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[4] The gel also protects aluminum conductors from corrosion in the presence of moisture. The use of gel for longitudinal water blocking of stranded conductors is a late development (1980s). The use of so-called super-absorbent polymers (SAPs) is an even later development and generally limited to the lower end of the conductor size spectrum.

- **Viability of Test Methods –** Test methods developed to meet distribution industry needs are not impaired by the type of taped conductor shield.

3.2.5 Insulation

The cable's primary insulation (C) is manufactured of materials that are designed with sufficient dielectric strength to withstand the voltage stress experienced during normal operation, as well as unusual voltage spikes and surges. The insulating material for most underground medium voltage nuclear plant cables is either XLPE or EPR. XLPE is formulated and supplied by standard chemical and physical manufacturing processes. Recent experience within the Transmission and Distribution (T&D) utility industry has led to the development of a tree-retardant (TR-XLPE) enhancement of this insulating material. The additives to TR-XLPE do not totally eliminate water trees; rather, they greatly reduce their rate of generation and growth. By contrast to the relatively limited number of variations in XLPE formulations, EPR cables are comparatively complex compounds that vary substantially between chemical and cable manufacturers. Different improvements of the EPR materials have evolved and have been distinguished from each other by color such as black, brown, or pink. The colors alone are not directly related to the way these materials age, but are indicative of the changes made to the formulations that improved the longevity of cables. Black EPR cables are early-generation EPR cables. Brown EPR appears to have been resistant to water-enhanced aging effects throughout the period of its use. Pink (or red) EPR cables are the more modern generation.

A typical dielectric constant for XLPE is ~ 2.3, while that for EPR is distinctly higher at ~ 3.2. Thus, EPR has relatively higher dielectric losses per unit length of cable, but is also generally more resistant to voltage stress and discharges. The dielectric loss through the insulation drains any charge that could build in the insulation at imperfections and eliminates high localized stresses that result in water-enhanced aging. Since medium voltage cable lengths in power plants are usually much shorter than T&D applications, electrical system losses were not paramount in the design of station cable systems. Thus, a majority of underground medium voltage cables at nuclear plants have EPR insulation, which has always had an expectation of greater operating life. The only current Class-1E medium voltage cable supplier is Okonite, which only offers the EPR-insulated qualified product. Thus, any Class-1E replacements are presently expected to be EPR cables. One exception to the XLPE or EPR insulation types is a Kerite-supplied material (HTK). For this paper's purposes, it can be thought of as responding similarly to EPR, only with even greater dielectric losses.

When HMWPE and XLPE first became available for medium voltage applications, they were hailed as the cure-all for many of the issues then facing the distribution world. These materials had very low losses in a high-stress electrical field, were easier to compound than rubber systems, were lower in cost than either rubber or PILC,[5] and were quite hydrophobic[6] while conventional rubber systems were not. Thus, widespread use was made of both varieties of PE by distribution utilities. Nuclear generating stations gave relatively little weight to PE's low loss characteristics because of the insignificant circuit lengths involved. Those few plant designers who did not choose rubber-insulated systems universally preferred XLPE to HMWPE for its

[5] Paper-insulated lead-covered.
[6] Hydrophobic - Having the tendency to not absorb moisture or water.

superior mechanical strength and thermal endurance. After large quantities of PE insulated cables were installed, early failures from water-treeing were observed. Knowledgeable sources in the distribution industry cite a seven- to ten-year threshold for the onset of significant water-treeing in typical HMWPE [Reference 12][7] with somewhat longer induction times for XLPE.[8]

- **Susceptibility –** The nuclear industry will generally be less susceptible to moisture-induced degradation due to its more widespread use of rubber and its avoidance of HMWPE.
- **Applicability of Literature –** The bulk of field and laboratory research has focused on HMWPE and XLPE and the development of TR-XLPE (Tree Resistant-XLPE). That segment of the literature is applicable to the few nuclear stations with XLPE insulation systems.[9] Since EPR has a differing failure mechanism, existing literature will be of lesser value to nuclear utilities that have utilized an EPR insulation system.
- **Viability of Test Methods –** As the water-treeing phenomenon associated with PE emerged about 1970, the scope of the potential impact was such that distribution utilities, cable vendors, and research companies began to seek solutions. The diagnostic methods that emerged were optimized for PE-based compounds. These methods are equally applicable in the nuclear industry to XLPE-insulated systems unless impaired by the shield construction as discussed below. Owing to the more complex formulations and differing or unknown failure mechanisms of rubber-based insulation systems, condition monitoring remains problematic.

3.2.6 Insulation Shield

Historically, 5 kV-rated cables could be purchased with or without a shield. Typically, 8 kV and higher rated underground cables at nuclear plants are shielded. The shield provides a ground plane over each conductor's insulation. This shielding confines the electric field within the insulation and produces a symmetrical radial distribution of voltage stress within the dielectric, minimizing the potential for surface discharges. In addition, the shielding limits radio-interference generation, allows for individual conductor insulation testing, and if properly grounded, reduces a possible shock hazard to plant personnel. The cable's shield over each insulated conductor is composed of a semi-conducting polymeric insulation shield or screen (D) and an overlying metallic component (E).

Semi-conductive thermoplastic or thermoset insulation shields are common in modern cables. Earlier cables used carbon-filled cotton tapes, which were ultimately found to be problematic and led to the development of superior extruded screens. The non-metallic insulation shield eliminates potentially ionizing and discharging air gaps between the primary insulation and the ground plane of the metallic shield. Helically wound, overlapping copper or bronze tape, or concentric copper wires form the metallic shield. Another variation (i.e., 'Unishield' design)

[7] Dudas notes that HMWPE had a failure rate of about five times that of XLPE.

[8] A separate panel of experts characterized time-to-failure for unjacketed cables as five to 10 years without distinguishing between HMWPE and XLPE. They postulated a 10- to 12-year time-to-failure for jacketed cables, again without distinguishing between the two insulation systems. [Reference 13]

[9] As noted above, the HMWPE failure rate well exceeded that of XLPE. Furthermore, plant designers made little use of HMWPE. In that respect, the statistical inferences that may be drawn from the literature have little value to nuclear plant personnel unless they are XLPE-specific.

applies several individual straight or corrugated shield wires embedded within a semi-conductive extruded jacket.

Both market segments (nuclear plant and distribution) made use of taped insulation shields in the 1960s and into the very early 1970s. The use of insulation shield tapes simplified production and ensured that the cable could be readily spliced or terminated.[10] During manufacture, the exposure of the insulation prior to application of the tape could lead to contamination of the interface. Such contaminants were subsequently identified at the root cause of water trees. As manufacturers switched to extruded semicons, so-called "dual-pass" systems were commonly utilized. While the extruded insulation shield was a definite improvement over the old tape method, the interface was still exposed to contamination before and during the second pass. Once the significance of this contamination was recognized, manufacturers eliminated the exposure through the use of three extruders on a single production line.[11]

- **Susceptibility –** Anecdotal evidence suggests that the nuclear market migrated to extruded insulation shields at least a couple of years in advance of the distribution industry. Since these early extruded insulation shields would have been applied with a dual-pass system, the risk of interface contamination would not have greatly changed. Both markets migrated to triple extrusion at about the same time. Thus, there would be little difference in susceptibilities to moisture-induced degradation between the two industries.[12]
- **Applicability of Literature –** Much of the literature from the time frame when tape insulation shields and dual pass extruded insulation shields (with its associated contamination) were utilized is associated with XLPE insulation issues. Since both market sectors utilized these insulation shield constructions, the literature will be equally applicable to nuclear wherever XLPE insulation was used. The literature is silent regarding the effect of interface contamination on rubber-insulated cable.
- **Viability of Test Methods –** Test methods developed to meet distribution industry needs are not impaired by the type of insulation shield.

3.2.6.1 Shielding: Metallic

Distribution cable designers have long favored wire shield technologies (flat strap and round wire). A variety of designs emerged based on the size of the neutral (as a function of the phase conductor circular mils) in an attempt to balance the need for an adequate return path for neutral and fault currents with the desire to reduce cable cost and weight. The robust nature of the strap and wire designs also facilitated deletion of the jacket as noted below, further reducing cost and

[10] The tapes were typically applied in a separate operation from the extrusion and cure of the insulation and thus no fibers could be encapsulated in the PE. The use of tapes facilitated termination and splicing since strippable semicons were not widely available until the late 1960s to early 1970s.
[11] The 1980s saw the introduction of so-called "1 + 2" extrusion, where the conductor shield was applied just upstream of a tandem extruder, which applied both the insulation and insulation shield. So-called "triple" extrusion, where all three layers are applied at once, did not become common until the 1990s.
[12] This is not to say that extruded semicons were not a significant technological advance. They were. The voids that inevitably occurred in tape systems at the tape overlap and at any wrinkles were prime locations for the initiation of corona. The extruded shields eliminated this concern. Equivalence was judged solely based on moisture-related concerns.

weight. Station designers had different jacketing objectives as noted below and were not limited to strap or wire shielding. Following conventional industrial service guidelines, most plant designers chose a helically applied copper tape shield (nominally five mils thick). Under normal service conditions, either design will bleed charge off of the semicon and carry the required fault current. A smaller set of plants utilized round wire shields but of a lighter gauge than were typically seen in distribution service.

- **Susceptibility –** The susceptibility of cable systems to moisture induced degradation is not influenced by the shield construction selected.
- **Applicability of Literature –** Aside from the influence on testing covered below; the literature related to moisture induced degradation is not influenced by the shield construction selected.
- **Viability of Test Methods –** Certain test technologies depend upon the signal propagation characteristics of the shield systems. As noted in the section, *Cable Testing*, the selection of a helical tape or small gauge wire shield construction may render those techniques unsatisfactory.

3.2.6.2 Shielding: None

As noted elsewhere in this paper, a number of 5 kV-rated, rubber-insulated nuclear plant cable systems are of an unshielded design. A limited number of distribution utilities followed this same practice at 5 kV, utilizing rubber and (to a lesser degree) XLPE insulation systems.

- **Susceptibility –** As noted above, the low stress levels associated with 5 kV rated cables systems reduce their susceptibility to conventional moisture-related degradation.
- **Applicability of Literature –** The literature has been silent with respect to the performance and moisture-related degradation of non-shielded cable systems.[13]
- **Viability of Test Methods –** As noted in the section, *Cable Testing*, the absence of a metallic shielding system renders this design unsuitable for evaluation using diagnostic systems developed for the distribution industry.

3.2.7 Jacket

Outermost sheaths (when they exist) protect the power cable's underlying insulation and shield the insulation from mechanical and some environmental damage. The cables may also contain assembled multiple insulated conductors under a common covering. While metallic armor designs may be used on some medium voltage constructions, essentially all underground power cables at nuclear plants have a non-metallic jacket (F) as their outer protective sheath (with or without underlying armor). The jacket materials include polyvinyl chloride (PVC), neoprene, and Hypalon. The transmission and distribution industry also favors a linear-low-density PE jacket material for moisture protection, but PE jacket material use in nuclear plants has been very limited. Jackets can slow but not totally eliminate moisture intrusion into the underlying cable core if the cable is submerged for prolonged periods (years). In the case of the unique shielded

[13] This silence may be due to the low usage of this product, the fact that most were rubber-insulated, or their very low stress levels compared to the higher-rated systems where moisture induced problems were most pronounced.

cable design with shield wires embedded within a semi-conductive jacket, the jacket serves a dual role as the insulation shield and the overall protective sheath.

A common practice of distribution cable designers in North America up until the mid-1980s was to omit the outer jacket, provided that a flat strap or round copper wire shielding system was employed. The strap or wires provided abrasion protection for the underlying semicon and insulation, and a low coefficient of friction surface to facilitate pulling. The result was a low-cost system with cables that were smaller, easier to pull and quicker to terminate. After the discovery of moisture-related degradation, distribution utilities moved to protect their cables through the application of polymeric jackets with polyvinyl chloride (PVC) being the early favorite. In the late 1980s distribution utilities adopted linear low-density polyethylene (LLDPE) jackets which further curtailed diffusion. In contrast, nuclear generating stations universally deployed flame-retardant designs that could only be obtained through the use of specially modified jacketing systems.[14] PVC and neoprene were the early choices with current designs favoring chlorosulfonated polyethylene (CSPE).

- **Susceptibility –** While not impervious, the existence of the non-metallic jackets on nuclear plant cables has greatly impeded the infusion of moisture into the insulation.[15] The presence of this additional diffusion barrier may help explain (along with some of the installation attributes discussed below) why moisture related degradation of medium voltage cable is just now becoming a concern for nuclear plants though cables are 25-35 years of age.
- **Applicability of Literature –** Aside from the length of the induction period, the applicability of the literature is not impacted by differences in jacketing philosophies.
- **Viability of Test Methods –** The test methods developed to meet distribution needs are not impaired by the presence of jacketing systems commonly utilized by nuclear plants.

3.3 INSTALLATION PRACTICES

3.3.1 Methods

The distribution industry makes widespread use of direct burial as an installation method. Thus, direct-burial installation exposes the cable to continuous, intimate contact with moisture and ion-laden soil. Omitting the associated raceway and concrete encasement typically associated with a conventional duct bank greatly reduces installation cost and disturbance of the right-of-way.

[14] The Unishield design, first marketed by Anaconda and described elsewhere in this paper, is the lone known exception. While maintaining the flame retardancy characteristic of jacketed constructions, its dual function semicon/jacket layer leaves this design with one fewer diffusion barrier than the typical nuclear cable design.
[15] Describes a construction that includes a metal-plastic laminate layer either over the semicon or under the jacket, which provides the necessary barrier to the infusion of moisture. The standard has been withdrawn by IEEE and is currently undergoing revision. Limited use has been made of this design system in the distribution market.

In contrast, most nuclear utilities favored the installation of duct banks, which were intended to be sloped and drained (or pumped). Inadequate maintenance of the drains and sumps during initial operations has somewhat reduced the advantages of this style of installation.

- **Susceptibility** – The widespread use of duct banks makes nuclear plant cable systems generally less susceptible to moisture-induced degradation than corresponding direct-buried distribution circuits.
- **Applicability of Literature –** Nuclear plant duct bank systems with their drains and sumps (even with the acknowledged lapses in their maintenance) would tend to ensure a much longer degradation induction period than is reflected in most distribution oriented literature.
- **Viability of Test Methods –** The viability of the various test techniques is not impacted except for those that specialize in pinpointing the location of defects. These are not as significant in plant applications, since those facilities tend to replace either the entire circuit or at least an entire run from one manhole to the next.

3.3.2 Terminations

In conventional distribution service, underground cables will frequently be terminated on overhead lines or equipment. The result is that such cables are exposed to lightning-induced surges. Such surges are characterized by their steep wave front with a high peak and short duration tail.

In contrast, underground cables in nuclear service are typically terminated in extremely well-shielded buildings, such that there is no lightning surge potential exposure. Nuclear plant cables will experience switching surges as a routine part of equipment operation. These surges are of a lower potential, with a shallower wave front and longer tail, and present less of a risk to the associated cabling.

- **Susceptibility** – Since lightning surges are one of the major mechanisms for conversion of water trees to electrical trees, distribution applications are at higher risk for surge-induced failure related to moisture degradation.
- **Applicability of Literature –** Based on the exposure to lightning-induced surges, the distribution industry has defined its insulation end-of-life dielectric strength as 200 volts per mil (vpm).[16] The nuclear industry has not developed an analogous end-of-life breakdown strength. Arguably, such a criterion developed for the nuclear environment would be even lower. Thus, the use of the 200 vpm figure cited in the literature represents a conservative position.
- **Viability of Test Methods –** The less-severe surge duty cited above theoretically means that test voltages applied in the generating station environment could be lower than those used in distribution service. In the absence of a consensus standard to establish those test levels for the nuclear market, users typically follow distribution-oriented test standards with the inherent conservatism described above [Reference 15].

[16] Typical new cable AC breakdown strength is in excess of 600 vpm.

3.3.3 Splices

Splices (or joints) are common in distribution networks since the length of circuits frequently exceeds the amount of cable that can be spooled onto reasonably sized shipping reels. In contrast, medium voltage circuits at nuclear generating stations rarely exceed available shipping reel capacities. Thus, splices are much less common in the underground networks at nuclear generating stations.

- **Susceptibility** – The susceptibility of cable systems to moisture-related degradation is not influenced by differences in splicing practices.[17]
- **Applicability of Literature** – The applicability of literature related to moisture-induced degradation is not influenced by the presence of splices or their type.
- **Viability of Test Methods** – Certain test methods are particularly well-suited for the diagnosis of splice integrity and workmanship.[18] Such methods are equally applicable to both markets unless limited by shield construction. The preferred splice designs also frequently differ in their stress-grading methodology and the nature of the difference is known to adversely impact tan δ testing. Distribution networks make widespread application of geometric graded splice designs (molded, cold shrink, and even tape). This method yields a linear voltage/current relationship. In contrast, nuclear systems predominantly favor heat-shrink designs that employ non-linear (i.e., high dielectric constant) stress-grading systems. The presence of non-linear stress grading materials may so dominate tan δ curves that true cable characterization is no longer feasible. This limitation is acknowledged in IEEE 400.2-2004 [Reference 16].

3.3.4 Accessories

Conventional distribution designs make extensive use of separable connector technology to both join and terminate cables. Generating station designs almost universally use some form of a permanent splice for connecting equipment supplied with pigtails (such as electric motors). The use of permanent connections (heat shrink or tape) means that the process of de-termination of the pigtails presents some risk to the field cables and pigtails. This is done at considerable expense. Recent advances in motor termination technologies may reduce the risk and effort of breaking the circuits for testing.[19]

[17] It is acknowledged that poorly installed splices represent a potential point of moisture ingress and in that sense increase susceptibility. This is, of course, true in both market segments.

[18] IEEE P400.3, *Draft IEEE Guide for Partial Discharge Testing of Power Cable Systems in a Field Environment.*

[19] In November 2004, Tyco/Raychem announced a new termination kit for 5 kV and 8 kV motors. An extension of earlier 600V termination technology, the medium voltage GelCap termination is a single-use device that is compact, low-cost, quickly applied, and quickly and safely removed. The silicone-based gel filling is compatible with EPDM and CSPE motor leads but not those insulated with silicone rubber. For further information concerning the gel, see [Reference 17] . For information regarding the 5/8 kV rated GelCap development, see [Reference 18]. The 3M Company announced an upgrade to its existing 5320 series medium voltage motor termination kits at the EPRI Large Electric Motor Users Group (LEMUG) winter 2005 meeting. The enhanced version, nominally the 5310 series, is low-cost and compact. Like the Tyco/Raychem version, it features quick application and removal. Unlike the Tyco/Raychem version, it is reusable and is compatible with all motor lead insulations. Both vendors are presently offering the kits as commercial grade items only.

- **Susceptibility** – The style of accessories has no impact on susceptibility to moisture-induced degradation.
- **Applicability of Literature** – The applicability of literature related to moisture-induced degradation is not influenced by the type of cable accessories used.
- **Viability of Test Methods** – The viability of test techniques is not impacted, although the termination/de-termination process at plants may make testing less desirable.

3.3.5 Cable-End Access

Conventional distribution circuit ends are readily accessible to manually transportable or truck-mounted test equipment, since most runs terminate in substations, on pole-mounted transformers, at disconnect switches, or in vaults. In contrast, medium voltage circuits in use at nuclear plants are typically terminated deep inside well-shielded buildings.

- **Susceptibility** – Aside from the reduction in surge potential common to nuclear plants noted above, the susceptibility of cable systems to moisture-induced degradation within the two market segments is not influenced by differences in cable-end access.
- **Applicability of Literature** – The applicability of literature related to moisture-induced degradation is not influenced by the degree of available cable-end access.
- **Viability of Test Methods** – The location of cable terminations in the nuclear market is such that access is typically limited to hand trucks or fork lifts. Test techniques applied in nuclear service must typically be chosen with a high premium on equipment size and portability.

3.3.6 Cable Mid-Run Access

Certain PD-based test methods require access to intermediate points of the cable to increase sensitivity of the readings or to facilitate location of a defect. Within distribution networks, mid-run manholes or vaults readily facilitate such access.

- **Susceptibility** – Cable susceptibility to moisture-induced degradation is not influenced by the degree of available mid-run access.
- **Applicability of Literature** – The applicability of literature related to moisture-induced degradation is not influenced by the degree of available mid-run access.
- **Viability of Test Methods** – Those methods that do not require mid-run access will, of course, not be impacted by this issue. Those dependent upon the installation of inductive or capacitive sensors at interval points in long runs may be less desirable for use in testing cables in safety-related duct banks at nuclear plants. In contrast to conventional manhole covers, such duct banks frequently include large and cumbersome “missile shields” to protect the cables from wind borne projectiles. Removal of numerous covers in a long run could substantially increase the total cost and duration of testing.

4 CABLE TESTING

4.1 PURPOSE

Field testing of electrical cables can generally be divided into two broad categories:

- Diagnostic
- Withstand

The purpose of the former is to characterize the age condition of the dielectric, while the latter represents a go/no-go challenge to the dielectric integrity of the system. While these two approaches can be used independently, they may also be applied in a complementary manner when a higher degree of confidence in the system is required.

The following paragraphs provide a broad overview of the topic of cable testing. For details of the various test techniques and a more exhaustive discussion of their strengths and weaknesses, the reader is directed to IEEE 400 [Reference 15][20], its various daughter documents [References 20, 21, 22][21] and the other cited references.

While these documents provide the user with insights into the various test technologies, the user must be aware that most techniques (and the related literature) were developed for the distribution industry. Though much of the technology readily translates to the nuclear industry, the differences in cable construction, preferred dielectric, shield construction, modes of degradation, and cable system architecture can impact or even negate that which passes for accepted practice in the distribution industry.

4.2 TESTING RESOURCES

In addition to the selection of an appropriate test technology, the user must also decide whether such tests will be performed by in-house staff or by one of the many testing services. The selection of certain test technologies will make this determination as those technologies are only available via testing service companies.

Purchase of the desired test equipment is primarily advantageous in that tests may be conducted with minimal advance notice. If this option is considered, users should recognize that there may be significant training required for advanced technologies and that data interpretation for most

[20] The IEEE Std 400 and its various references also identify diagnostic and withstand techniques other than those described in this paper, which are less commonly applied in the US (Isothermal Return Voltage, Isothermal Relaxation Current, Dielectric Spectroscopy and Oscillating Wave). For a more detailed discussion of these techniques, see Reference 19.

[21] IEEE 400.2 [Reference 21] was successfully balloted in late 2004 but has yet to be published by IEEE. The other two documents are still being developed by their respective working groups. All three were developed by the IEEE's Insulated Conductors Committee. For further information, consult the ICC website at: http://www.ewh.ieee.org/soc/pes/icc/

diagnostic systems is rarely straightforward. In contrast, withstand systems are well-suited to independent operation by plant personnel given their go/no-go character.

In the evaluation and selection of equipment for purchase, prospective buyers should be aware that some withstand test sets may be augmented with diagnostic accessories. The selection of integrated systems may not only reduce the net capital outlay but also training, calibration, and maintenance costs.

4.3 SHIELDED VERSUS UN-SHIELDED TESTING

The various techniques described below depend on the existence of some kind of concentric shielding system. During testing, the shielding system (typically consisting of a semicon layer and copper tape or set of copper wires) confines the electrical stress to the dielectric and provides a low impedance return path for leakage current or pulses emanating from discharges internal to the dielectric.

Many nuclear plants have an unshielded 5 kV cable system. In the absence of a concentric shielding system, present diagnostic methods cannot be expected to produce meaningful results. Of greater concern, under the right circumstances, such testing can pose a risk to the cable's integrity since the distorted distribution of stress in the insulation due to large variations in the resistance of the insulation return path may lead to localized damage or circuit failure from overstress during testing.

Users of unshielded cable systems should give consideration to alternate methods of cable system evaluation. Such evaluations should ensure that their cable system's failure history (if any) is well-documented and that all failures are rigorously analyzed by a reputable laboratory to establish the actual mechanism of failure. Once a rigorous failure evaluation is performed, the applicability of the failure mechanism to remaining like circuits can be determined and appropriate action may be taken.

In the absence of sound failure analysis data, users of unshielded medium voltage cable systems might consider sacrificial replacement of a segment of a representative underground circuit when 35 to 40 years of service have passed. The extracted segment could be subjected to a wide range of destructive tests in order to establish the age-condition of the balance of the installed cable systems. Cables in systems that have survived 35 to 40 years with no failures obviously did not contain manufacturing defects nor have any installation damage. Accordingly, the only significant concern would be long-term, water-enhanced electrical degradation. Testing of the removed cable would indicate whether or not satisfactory service could be expected of the remainder of the system.

4.4 TESTING METHODOLOGIES

4.4.1 General

When performing any high-voltage test, proper preparation, insulation, and isolation of the cable ends are required. In general, the cable ends require separation from all elements that are not to be subjected to test by at least 10 kV/inch of test potential when conducting a withstand test and substantially more when performing diagnostic testing.[22]

Since there is a presence of lethal voltages, all cable termination ends and all connecting leads should be protected against accidental contact by such means as barriers, enclosures, or watchmen.

4.4.2 Diagnostic Methods[23]

Diagnostic methods quantitatively evaluate one or more characteristics of the cable insulation system. The results are most meaningful when compared with baseline readings taken on new cables or when trended over a long period of time. While the ideal diagnostic test would evaluate the overall condition of the cable and identify localized defects, the current state of the technology is such that users must choose between these two attributes when selecting a methodology. For instance, when choosing a method that evaluates the overall condition of the dielectric, users must be aware that test results provide no indication of the existence or condition of any localized defects. Likewise, methods that identify localized defects provide no indication of the overall condition of the cable. Until a single test is developed that considers both attributes, users should consider the complementary application of diagnostic techniques or a diagnostic and a withstand test.

Finally, it should be noted that prevailing diagnostic techniques were developed for the distribution industry. Traditional network design philosophies within that industry have resulted in the overwhelming deployment of XLPE-insulated cables and in the resulting emphasis on water-tree-related degradation. In contrast, recent surveys have shown that the majority of US nuclear plants have deployed EPR-insulated medium voltage cables[24]. Users should be aware

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[22] Users should note that the test electrode geometry has a great influence on the safe clearances. The values recommended above are only for conditions where high voltage and ground electrodes are smooth and uniform, and where energized connections are made with round conductors of adequate size to avoid corona. If the test connections are not smooth, larger clearances should be provided.

[23] When applied to sound insulation systems, diagnostic methods are non-destructive. If the dielectric has been severely degraded as a result of physical damage or aging, the application of even limited voltages and durations may cause the cable to fail. Thus, as with the application of any meaningful test, users should be prepared for such failures and have the necessary cable, splices, terminations and lugs on hand to facilitate repair or replacement. Withstand methods are not considered diagnostic in the sense presented here, since such methods are intended to break down weak or defective regions.

[24] Designers of distribution networks have long favored cross-linked polyethylene (XLPE) insulation due to its low cost and losses compared to EPR. When the material first became available, it was believed that its hydrophobic character made it the ideal dielectric for use in wet environments. The discovery of water-treeing as the prime mode of degradation laid this notion to rest but it did not significantly reduce the amount of XLPE being installed in distribution networks. Compound suppliers responded to the increasing water-tree failures by developing a class of "tree-retardant" XLPE (TR-XLPE) cables, which holds an ever-increasing share of the distribution marketplace. TR-XLPE represents a "middle ground" between conventional XLPE and EPR in both losses and costs but has had

that this latter class of materials can (and does) exhibit modes of degradation in the presence of moisture that are distinctly different from XLPE.[25] The lack of research into basic failure modes of EPR-insulated cables in the presence of moisture and the lack of research into associated diagnostic equipment makes the selection of appropriate method(s) and acceptance criteria all the more difficult.

4.4.2.1 Direct Current Methods

(Leakage Current, Insulation Resistance, and Polarization Index)

Direct Current (DC)-powered diagnostic testing was for many years the preferred method for evaluation of electrical cables in the field. This preference was due to the low cost, portability of the test sets, and ease of operation. Traditional DC-based evaluations included the assessment of the leakage current, insulation resistance, and the determination of the system's polarization index. There is much debate in the industry regarding the meaningfulness of such results.[26] The debate stems from the different manner in which electrical stresses are distributed during DC testing compared to in-service AC stresses. During DC testing, stresses will be distributed according to the cable geometry and the electrical resistance of the dielectric. In contrast, under AC loading, stresses will be distributed according to the cable geometry and its capacitance (dielectric constant). Under ideal conditions, the difference will not be significant; however, the presence of contaminants or moisture within the dielectric can greatly influence the distribution of stresses when performing high-potential DC testing and lead to abnormal stress conditions in any remaining dry regions [Reference 24].

High-voltage DC diagnostic testing of cable is performed with a DC hi-pot set, typically in conjunction with the required withstand tests. Such tests are performed with the cables off-line and isolated from their end equipment. Tests may be performed following a step voltage or constant voltage protocol. Research has shown no clear correlation between the results and the existence of water trees or large defects. Near end of life, DC hi-pot testing can predispose XLPE to failure because of the accumulation of space charge.[27]

Low-voltage DC diagnostic testing presents a low risk to the cable for the accumulation of space charge, but the results generally lack meaningfulness. Such tests are typically performed with a

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extremely limited deployment in nuclear service to-date. Prospective users of TR-XLPE should be aware that most existing diagnostic methods were developed with conventional XLPE in mind and that not all will provide meaningful analysis of TR-XLPE conditions.

[25] Since the earliest rubber insulation systems were commonly black, optical failure analysis has proven to be difficult; definitive identification of the cause of failure has often been problematic. The wet electrical stability of most early rubber insulation systems was typically limited by the filler system utilized. Compared to modern dielectrics, the early clay fillers were ineffectively treated, resulting in a high uptake of moisture over time. Other additives sometimes used to control compound acidity exhibited high volumetric expansion when exposed to moisture, resulting in a potential permanent distortion of the electric field.

[26] IEEE 400-2001 [Reference 15] concludes that, "*The value of the* (DC) *test for diagnostic purposes is limited when applied to extruded insulations*".

[27] For further information on these concerns users are directed to references B7, B21, B23, B47 and B48 of IEEE 400-2001 [Reference 15] and to References 24 and 25

megohmmeter.[28] Both high- and low-voltage DC tests are conducted with the cables off-line and isolated from their end equipment.

As a result of the above concerns, IEEE 400 no longer endorses the application of DC as a diagnostic method for extruded insulation systems. It is clear that this position was taken largely because of the large installed base of XLPE-insulated cables in distribution systems. While it is noted that the application of DC to rubber (EPR and butyl) insulation systems is not subject to space charge accumulation concerns, the concerns for value of the DC-diagnostics remain.

4.4.2.2 Dissipation Factor

Dissipation factor (also called tan δ or loss angle[29]) is a diagnostic method used to assess the quality of cable insulation. While preferably used as part of a trending program, single test readings may also be used to try to predict remaining life or prioritize cable replacement. When the insulation is sound (i.e., no water trees, voids, or moisture), a cable is essentially a long coaxial capacitor. In the ideal capacitor, current and voltage are 90 degrees out of phase. In contrast, service-aged cable frequently contains water trees, voids, and moisture. These result in an increase in resistive current through the insulation. Under such conditions, the dielectric no longer mimics the ideal capacitor and the resultant phase shift will be something less than 90 degrees. The degree to which the dielectric departs from the ideal capacitor is an indication of insulation degradation, assuming the dielectric was a low-loss (low resistive leakage current) material initially. This assumption is true for XLPE but not true for EPR and TR-XLPE.

Diagnostic systems based on tan δ are available for both power (50 or 60 Hz) and non-power frequencies (typically 0.1 Hz)[30]. Tests have shown that the magnitude of the loss angle increases with decreasing frequency.

The tan δ unit consists of a high-voltage divider, an analysis unit, and a resonant AC or VLF hi-pot set as the power supply[31]. The cable to be tested must be de-energized and each end isolated from ground and from its associated end device. Using the hi-pot set as the power supply, the test voltage is applied to the cable while the analysis unit takes measurements. The divider measures the voltage and current input to the cable and sends this information to the analysis unit where the calculation of tan δ occurs. Typically, the voltage is raised in steps with measurements taken up to normal line-to-ground operating potential. If the measurements are indicative of sound insulation, the voltage is then raised to 1.5 to 2 times normal line-to-ground. The measurements at the higher voltages are compared to those at lower voltages and an assessment of degradation is made. If the insulation is free from defects, the measured results

[28] Low-voltage DC-powered diagnostic testing of medium voltage cables is typically performed at 2500 volts, though testing at 500 and 1000 volts is also common.

[29] The terms dissipation factor, loss angle (in radians), and tan δ are used interchangeably. While this is not mathematically correct, the values are equivalent over the range of angles of interest.

[30] Bahder, et al. first used dissipation factor measurements to monitor aging and deterioration of extruded dielectric cables. Reference 26. Bach, et al. reported a correlation between an increasing 0.1-Hz dissipation factor and a decreasing insulation breakdown voltage level at a power frequency that was mainly determined by water-tree damage of the cable insulation and not by water along the conducting surfaces [Reference 29].

[31] VLF power supplies are available with both sine and non-sine waveforms. While either waveform may be used for withstand testing, a sine wave output power supply must be used when performing a diagnostic assessment.

will change little with increasing test voltage. If there is insulation degradation, the measurements will be voltage-dependent, rising with increasing voltage. The measured values are used as figures of merit to grade the condition of the cable insulation as "good", "aged", or "highly degraded".[32] Those found to be in "good" condition may be returned to service and periodically monitored. Those found to be "aged" may be returned to service and periodically monitored with a shorter interval. Those cables found to be "highly degraded" should be replaced as soon as possible.

Diagnostic assessment of medium voltage power cable using tan δ is recognized to have the following strengths and weaknesses:

- The method evaluates the overall cable condition. It does not locate discrete defects. The method is most meaningful when used on lengths of cable that have been exposed to the same aging conditions.
- This method is well-suited for categorizing a large population of installed cables as candidates for immediate action, frequent monitoring, or routine monitoring.
- The sensitivity of the method to the existence of water trees is better at non-power frequencies (i.e., VLF) than at power frequency.
- The test gives the best results when comparing present measurements against established historical figures of merit for a particular cable.
- It is best performed on circuits containing a single type of dielectric (i.e., all XLPE or all EPR).
- The length of the circuits that may be evaluated is limited by the amount of capacitance in the circuits under test and the size of the power supply.
- No industry consensus exists on the correlation of this method to the performance of tree retardant XLPE or rubber insulation systems.
- True cable condition can be masked by the presence of splices that employ high dielectric stress-control materials.

4.4.2.3 Partial Discharge Off-line

In general, cable fails as the result of anomalies in the distribution of electrical stress within its dielectric. Such distortions may result from the presence of contaminants, voids, age-induced defects, or manufacturing defects. With growth over time or when overstressed during testing or service, such anomalies may result in localized electrical discharges that partially bridge the dielectric material between the energized conductor and ground. As the AC voltage wave rises from 0, a large portion of voltage is distributed across the defective section of the dielectric. As the voltage continues to rise, the defective section of dielectric conducts and the voltage distributes across the remaining section of insulation. This is called partial discharge or PD; it is localized in character and causes a radio frequency disturbance that propagates along the length of the cable. Typical defects within extruded cable systems that can be sources of PD include

[32] See IEEE 400 for acceptance values for unfilled XLPE. Since there are wide variations in formulation of rubber insulations, it is unlikely that a single set of acceptance values will ever be published for this material. EPRI report 1009017 [Reference 8] contains a limited assessment of dissipation factors for five modern EPR cables, including those being used as replacements for nuclear plant cables. Unfortunately, no specimens of the rubber most likely to see moisture-induced degradation (early vintage black EPR) were included.

internal cavities, interfacial voids, broken shields, electrical trees, protrusions, knife cuts, contaminants, and poorly installed accessories. PD characteristics (magnitude, repetition rate, phase, etc.) are known to be a function of the size, location, and type of defect encountered, voltage, time, temperature, and dielectric type.[33] Systems have been developed to facilitate field detection and location of the sources of cable system PD. Such testing is recognized by IEEE 400. [Reference 15][34]

One method of PD testing, known as "off-line," is performed with the cable disconnected from its end equipment. The typical off-line PD test set includes a VLF or resonant AC, variable voltage power supply, capacitive and inductive sensors, an input impedance network, a digital signal processor, and a computer for data analysis and storage. A typical test involves the exposure of the cable system to a brief over-voltage (up to $2V_o$). During the period of voltage increase, the system looks for the onset of PD. The voltage at which this occurs is known as the PDIV (PD inception voltage). The elevated voltage needs to be maintained no longer than is required to obtain the necessary PD data. During the period of voltage reduction, the system looks for the voltage at which no PD above the background level can be detected. This is known as the PDEV (PD extinction voltage).[35]

PD location is typically accomplished in the time domain. Pulses generated by the discharge at the defect site travel along the cable in both directions and are reflected. As with other reflectometry methods, defect sites may be located through analysis of the waveforms.

PD systems are well-suited for evaluating the workmanship of splices, terminations, separable connectors. They also are adept at identifying local voids and contaminants in the cable dielectric. Yet, there is some controversy regarding their ability to detect the existence of water trees. In principle, the string of microvoids connected by oxidized channels that makes up a water tree will not discharge under elevated voltage stress, since the ionic water residing in the tree channel will inhibit the existence of the high local stress necessary for PD to occur. Nonetheless, some data is emerging that supports the contention that PD systems will detect water trees in a secondary manner by detecting the presence of electrical trees at the tips of the water tree channels. Historically, it has been assumed that such electrical trees would not emerge until the last moments of insulation life and that electrical treeing would progress to failure in a very short time frame. The presumption has been that the identification of electrical treeing during this very short window in time would be the product of luck. The emerging data

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[33] As with the other test methods addressed herein, the techniques were developed in the distribution industry and thus the bulk of the experience is with unfilled XLPE. Rubber insulations are inherently more discharge-resistant because of their high mineral filler content. Data from EPRI report 1009017 [Reference 8] showed negligible change in the PD levels of five modern EPR cables as a function of aging. Detection of manufacturing defects and workmanship issues with splices and terminations using PD would be expected to remain viable for these new materials. Older rubber [e.g., butyl and natural rubber] insulations that were unstable in water due to swellable or extractable constituents would be good candidates for PD evaluation (provided their shielding system supports signal propagation).

[34] The method is described in detail in draft IEEE P400.3 [Reference 22]

[35] The PDIV and PDEV data collected can be used to characterize the cable system. Typically, where the PDIV exceeds 2Vo, the system can be characterized as "very good." In those cases where the PDIV is low (just above Vo), the cable system can be characterized as "very bad." In between these conditions, interpretation is not as clear, given the many variables involved in PD generation and propagation.

is challenging this by purporting to find small electrical trees (associated with water trees) that may persist for years -- even in unfilled XLPE – without failure.[36]

Users should be aware that in addition to circuit length, shield characteristics and cable condition can greatly influence the propagation of PD pulses along the cable. Thus, the overall sensitivity of the measurements is also affected.[37] Critical considerations include shield characteristics (type, size, and condition) and properties of the semicon. These limitations can be substantial for some of the shield constructions common in nuclear power. For instance, many utilities utilize helically applied copper tapes shields. When new, this construction provides for excellent propagation of discharge signals owing to its low conductivity and high cross-sectional area. When field-aged in a wet environment, the turn-to-turn resistance of the tape significantly increases. Under that condition, the tape shield appears as a very long inductor to any high-frequency pulse. The sensitivity of a PD system would be very poor for such conditions (meaning that very high discharges could go undetected). Similar limitations would exist where the shield consists of a low number of small wires. In this case, the small cross-sectional area of the shield results in high attenuation of PD pulses. PD system sensitivity for the cable under test is typically determined by injecting calibration pulses of a known magnitude into the cable and verifying their detectability. The minimum level pulse that can be detected establishes sensitivity.

Diagnostic assessment of medium voltage power cable using off-line PD diagnostics is recognized to have the following strengths and weaknesses:

- Off-line PD systems are moderately expensive. The use of testing service companies is a common alternate to equipment purchase.
- Tests may be performed using power frequency or VLF power supplies.
- The size of power frequency-based sets may limit access to cable ends in a generating station environment.
- The method identifies the existence of PD within the cable or accessories and locates the site of the discharge.
- The method does not provide indication of the overall condition of the cable. (It provides an indication of the condition of sites with PD, which is not necessarily indicative of the degree of water-enhanced degradation.)
- Shield construction and condition greatly influence system sensitivity.
- Proper interpretation of off-line PD data requires a high degree of skill.

[36] It is surmised that the electrical trees may have been initiated during very high surges but that the cable's PDEV is high enough that sustained discharging does not persist under normal conditions. For more detail see Reference 27,

[37] These same wave propagation characteristics also impact PD source location accuracy. While location accuracy is of major concern in distribution service where the direct-burial method is common, it is expected that the degree of location accuracy is less-critical where cables are installed in duct-bank systems. This is true for two reasons: 1) In duct-bank applications, "repair" typically means that an entire section (manhole-to-manhole) would be replaced anyway, so precision is not as critical. 2) Access to the cables at manholes allows the use of locating devices, an option not available to buried cables without some trenching.

4.4.2.4 Partial Discharge On-line

An alternate method of diagnostic testing is known as on-line PD testing[38]. This method differs from the off-line approach primarily in that the cable is evaluated while in service (i.e., connected to its end devices and under normal system voltage). No external power supply is required. On-line PD system equipment includes capacitive and inductive sensors, an input impedance network, a digital signal processor, and a computer for data analysis and storage.[39]

On-line PD systems can be used to evaluate the quality of splice workmanship or the presence of cable manufacturing defects.[40] Proper analysis of observed PD enables identification and location of the source. As described above, PD systems will not identify the existence of water trees unless those trees have already been converted to electrical trees and are in discharge during the period of the "test."[41]

Diagnostic assessment of medium voltage power cable using on-line PD diagnostics is recognized to have the following strengths and weaknesses:

- On-line "testing" presents no risk to the cable system since no over-voltage is imposed.
- No outage is required to perform the "test."
- Proper interpretation of on-line PD data requires a high degree of skill.
- The method identifies the existence of PD within the cable or accessories and locates the site of the discharge.
- The method does not provide indication of the overall condition of the cable. It provides an indication of sites with PD, which is not necessarily indicative of the degree of water-enhanced degradation.
- Shield construction and condition greatly influence system sensitivity.

[38] "Testing" is perhaps a misnomer since there is no voltage imposed on the cable system by the off-line system. The system simply monitors the cable for presence of PD. On-line PD systems are recognized in IEEE P400.3 [Reference 22].

[39] While on-line systems do not require de-termination from end devices, access to the cables in intervening manholes may be required for maximum sensitivity. Such access is routine in distribution networks but could pose a significant impediment to testing of safety-related circuits at nuclear stations where security considerations may limit the number of manholes opened at any one time and the removal of manhole covers and so-called missile shields is a significant effort.

[40] Though arguably not as effectively as an off-line PD system.

[41] At least one supplier of an on-line PD system claims to have overcome the limitations imposed by testing at service voltage only by the detection of "pre-discharge signals," a concept that has not been yet accepted by consensus of the industry.

4.4.3 Withstand Methods[42]

Withstand testing has been traditionally performed at the factory as the final step in production of electrical cables. Such testing was intended to ensure that the cables, as shipped, were free of significant defects or damage. Such testing has typically been performed using DC or power frequency AC[43].

In the field, withstand testing has been applied at a slightly reduced level at time of cable installation to ensure that the rigors of the installation process did not result in adverse degradation of the insulation system and to ensure that cable accessories have been properly installed.

Withstand testing is not predictive in nature. Such methods identify only the weakest point in the insulation and are of a go/no-go character. The cable under test either passes or fails. This has been traditionally interpreted as affirming that the cable is suitable for return to service and able to withstand typical voltage transients within a well designed system. The test also verifies that no serious defects exist in splices and terminations that would lead to early failures.

As with all withstand test methods, the test specimen must endure the application of the specified voltage for a set period of time without breakdown of its insulation. The magnitude of the specified voltage is above the normal system voltage. If the cable's insulation is sound, no degradation occurs. If the insulation system is sufficiently degraded or a significant installation damage or defect is present, a breakdown can occur during testing.

Such go/no-go testing is appropriate following installation, splicing, and terminating activities. If the cable is suspected of being heavily water-treed, diagnostic testing previously described is typically employed prior to withstand testing to assess the overall condition of the insulation and avoid a cycle of test/repair/test/repair/test/repair, etc. If the diagnostic tests show evidence of extensive degradation, the cable can either be immediately replaced or returned to service without withstand testing (and failure) while replacement cable is being obtained and planning is underway. [44]

Unlike diagnostic testing, where leakage currents are monitored and an attempt is made to diagnose the quality of the insulation, withstand testing is simply go/no-go or pass/fail. The test object either holds the voltage or fails. The test is performed at a notably high voltage to assure that the cable has sufficient capability to withstand normal operating voltages and surges for a

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[42] When applied to sound insulation systems, withstand methods are non-destructive. Nonetheless, if the dielectric has been severely degraded as a result of physical damage or aging, the application of these voltages is intended to cause the cable to fail. Users should be prepared for such failures and have the necessary cable, splices, terminations, and lugs on hand to facilitate repair or replacement.

[43] It should be noted that DC has been deleted as an acceptable test method for factory testing in most industry standards.

[44] Users should be aware that cable life may potentially be extended through injection of a low-viscosity silicone fluid. Injection requires the breaking of splices and the removal of terminations. The total cost for such restoration, while less than the cost of cable replacement, is still significant. The intent of such injection is to fill water-tree channels and thus restore lost dielectric strength. It cannot overcome the myriad of other material and production-related shortcomings common to cables manufactured in the 1960s and 1970s. For more information on restoration see http://www.cablecure.com/ or http://www.novinium.com/

significant period. Yet, the test provides no direct indication of the length of that period. Should the cable fail during the test, conventional fault-locating methods can be used, the repair/replacement made, and the test repeated. Most test sets have the capability to "burn-down" a fault (i.e., continue to put energy into the fault to produce a low impedance carbonized fault channel, which can then be found with conventional TDR or PD equipment.)

4.4.3.1 Direct Current Withstand Testing[45]

Direct Current (DC)-powered withstand testing was for many years the preferred method for validating the integrity of electrical cables following installation and application of accessories. The portability, ease of use, and economy of DC test sets established a benchmark for field testing that competing technologies are only now beginning to approach.

Depending on the rating of the hi-pot set, units could consist of integrated or separate control and high-voltage modules. Testing was performed with the cables off-line and isolated from their end equipment following either a step voltage or constant voltage protocol. Research has shown no clear correlation between the results and the existence of water trees or large defects. It also indicates that high-voltage DC can predispose XLPE to failure because of the accumulation of space charge.[46]

As a result of the above concerns, IEEE 400 no longer endorses the application of DC as a withstand method for extruded insulation systems. It is clear that this position was taken largely because of the large installed base of XLPE-insulated cables in distribution systems. While it is noted that the application of DC to rubber-insulation systems is not subject to space charge accumulation, the concerns noted above for meaningfulness of the DC-based diagnostics remain.

4.4.3.2 Alternating Current Power Frequency Withstand Testing

Power frequency withstand testing is the preferred method from a dielectric standpoint since the insulation is stressed in exactly the same manner under test as in service. Yet, other attributes (size, cost, available accessories) may favor alternate techniques. In contrast to DC, the reversal of voltage polarity every half cycle during AC testing ensures that potentially harmful space charges will not accumulate. In spite of these benefits, testing with AC was for many years limited to the factory environment due to the bulk and cost the equipment required to supply charging current to the cable system.[47]

The development of series resonant test sets reduced both the size and cost of the equipment to where it can be easily mounted in a small truck or van.[48] Such trucks are widely used in distribution service where the vehicle can typically gain access to within 50 or 100 feet of the

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[45] See the Diagnostic Methods section for additional considerations of the application of DC to extruded dielectrics.
[46] For further information, see the references cited in the Diagnostics Methods section.
[47] As previously noted, a medium voltage cable electrically appears to be a very long, cylindrical capacitor. Every half cycle, the capacitance must be charged and leakage current supplied. While the leakage current component is extremely small even for aged cables, the magnitude of charging current can be substantial.
[48] IEEE P400.3 [Reference 22] recognizes two types of resonant-test sets used in cable testing: Inductively Tuned and Frequency-Tuned. The former has the advantage of simplicity of wave shaping. The latter has the advantage of having no moving parts and being lighter.

ends of the cable. Unfortunately, such accessibility is rarely achievable within the nuclear generating station environment.

AC testing is recognized in the US in IEEE standards for post-installation and maintenance withstand assessments of cable by IEEE 400 [Reference 15]. The general practice is to subject the cable to two to three times its normal line-to-ground voltage (V_o) for the designated test period, with some reduction for the age of the cable system.

4.4.3.3 Alternating Current Very Low Frequency Withstand Testing

Very Low Frequency (VLF) withstand testing utilizes AC power ranging in frequency from 0.01 Hz to 0.1 Hz. The primary advantage of VLF is that the charging power is reduced in direct relation to the reduction in frequency (i.e., at 0.1 Hz it is but one six-hundredth of that at 60 Hz). This enables the manufacture of small, lightweight, low-cost test sets on the same scale as those traditionally used in DC testing. Since the applied waveform is of an alternating polarity, there is no space charge accumulation such as occurs with the application of DC. The use of an AC source further ensures that stress is distributed within the insulation in a manner similar to that of normal service stresses.

Several different VLF waveforms have been utilized with the most common being sinusoidal and cosine-rectangular (or trapezoidal). Either waveform is suitable for use in withstand tests.

VLF testing is recognized in the US in IEEE standards for cable (IEEE 400 [Reference 15] and IEEE 400.2 [Reference 21]) and for rotating machinery (IEEE 433 [Reference 29]). Of the two types of VLF cable testing (withstand and diagnostic) recognized by the standards, by far the most commonly performed are post-installation and maintenance withstand assessments. The general practice is to subject the cable to two to three times its normal line-to-ground voltage (V_o) for the designated test period, with some reduction for the age of the cable system. European standards sometimes invoke a sixty minute duration for VLF testing, reasoning that duration should be extended to increase the total number of cycles at the lower frequency. In the US, IEEE 400.2 [Reference 21] invokes a thirty-minute installation test and a 15-minute maintenance test. The IEEE's position is based in part on extensive field test data, which has shown that more than 67% of VLF test failures occur within the first 15 minutes and more than 88% within 30 minutes [Reference 30].

5 NEI MVU CABLE SURVEY

5.1 SURVEY PURPOSE

The purpose of the survey was to identify the MVU cable types in use, their insulations and shielding systems, and their generational differences. Additionally, the survey was to identify failures that occurred under wet conditions and link them to the cable types.

5.2 SURVEY SCOPE

Shortly after the NEI Task Force was formed, it was agreed that much more data from the individual plants was needed before any aging-related failure conclusions could be drawn. Thus, a comprehensive survey was designed in January 2005 to capture the following types of information:

- Contact information for all industry cable experts
- Extent of medium voltage cable that is installed underground for safety-related and critical functions, along with attribute data concerning:
    - Circuit numbers (or number of circuits, if details were not immediately available)
    - Rated and applied voltage levels
    - Cable manufacturer, insulation type, and color
    - Cable age (based on year installed)
    - Cable functions
    - Cable conductor shield attributes and insulation shield attributes
    - If failures occurred, information about the failure root cause and cable replacement

Most survey data was collected in February and March 2005. Some plants conducting refueling outages may not submit the data until later; however, sufficient information now has been collected, when combined with other information discussed in Section 2, for analysis and conclusions appearing in this White Paper.

5.3 SURVEY RESULTS EVALUATION

5.3.1 Contributors

81 units (51 plants) provided information to the general survey questions. 74 units (47 plants) provided information on originally installed cables, failures, and replacement cables.

5.3.2 Underground Circuit Quantities

All 81 responding units reported some underground cable applications. 65 (80%) units reported use of underground conduits; 76 units (94%) reported underground ducts; and 23 units (28%) reported some direct buried circuits. 21 units (28%) reported having enclosed trenches with cables supported within the trench.

The number of circuits per plant was quite variable and appears to relate to vintage. For the 75 units providing data, the total number of circuits identified was 8,509. This quantity is for wet and dry applications underground and in plant. The average number of circuits per unit was 113 circuits with a high of 376 per unit and a low of 4 circuits per unit.

77 units provided data on the number of underground circuits; the total number of circuits was 2,767. The average number of underground circuits per unit was 36 with high being 214 and the low being 2 per unit. The ratio of underground circuits to total medium voltage circuits was 0.32. Of the plants reporting underground circuits, 31 percent indicated the circuits were dry and 69 percent indicated that the circuits were subject to wetting.

5.3.3 Installed Cable Types

Most respondents indicated use of 5-kV rated cables in underground applications operating at 4.16-kV. Some units reported more than one type of cable in use.

Butyl rubber is an insulation that was in use in the late 1960s and very early 1970s; it was used at few sites. The material was replaced by black ethylene propylene rubber (EPR), cross-linked polyethylene (XLPE), and brown EPR. In the late 1970s to early 1980s, EPR manufacturers recognized improvements in longevity to be had by improving the coating of clay fillers to make them non-hydroscopic. The black pigment was replaced with red pigment to indicate the generational difference. It should be noted that EPR is a compound and each manufacturer's formulation is somewhat different from others. Some variations in behavior may exist due to formulation and overall cable design differences.

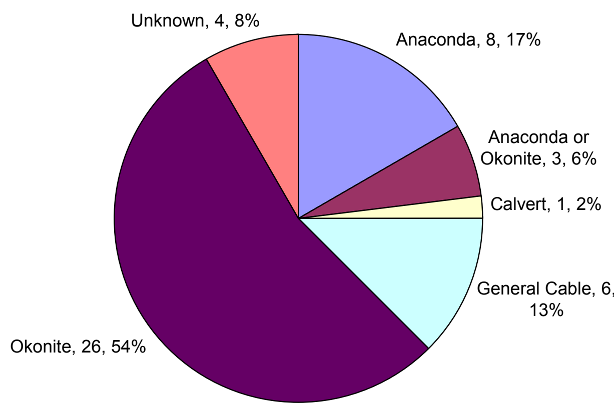
Table 5-1 provides a listing of the 5-kV rated insulation types by number of units reporting the material.

Table 5-1
Originally Installed 5-kV Insulation Types

Insulation	Units	Percent of Reporting Units
Butyl Rubber	4	5
EPDM	1	1
Black EPR	48	65
Brown EPR	20	27
Red EPR	31	42
XLPE	23	31

Figure 5-1 shows the distribution of manufacturers for the black EPR insulated cables. Okonite and Anaconda were the dominant manufactures. The brown EPR is manufactured only by Kerite. The red EPR was manufactured by either Anaconda (9 units reporting use) or Okonite (21 units reporting use). One unit reported having both Anaconda and Okonite red EPR.

Figure 5-1
Manufacturers of 5 kV Cable



24 units reported having 8-kV rated cable in use on systems operating at 6.9-kV. Plants having 6.9-kV systems tended to be constructed in the late 1970s and beyond such that a lower percentage of the plants had black EPR insulations for 8-kV rated cables than for the 5-kV rated population. In addition, 6.9-kV systems were not adopted by most utilities even in later plants. Some later plants remained with 4.16-kV systems for the bulk of the plant and used 13.8-kV systems to supply large loads such as the circulating water pumps. Table 5-2 provides a distribution of the insulation types in use.

Table 5-2
8-kV Cable Insulation Materials

Insulation	Units	Percent of Reporting Units
Black EPR	8	11
Brown EPR	2	3
Red EPR	20	27
XLPE	7	9

40 units reported having 15-kV rated cables operating at 13.2-kV to13.8-kV. These cables are used for distribution to large loads and feeds to 13 to 4 kV transformers. Table 5-3 provides the distribution of the insulation types in use.

Table 5-3
15-kV Cable Insulation Materials

Insulation	Units	Percent of Reporting Units
Butyl	1	1
Black EPR	21	28
Brown EPR	9	12
Red EPR	26	35
XLPE	9	12

20 units reported use of cables rated at 25-kV and 35-kV. The 35-kV cables were used in 34.5-kV operating systems associated with off-site power feeds. The 25-kV cable was used in 22-kV circuits between the generator output and auxiliary transformers.

Rather than having extruded polymer insulation, some cables are insulated by oil impregnated paper with an overall sheath of lead. PILC stands for Paper Insulated Lead Jacketed Cable. Only a few plants reported using PILC type of cable and even at those plants, extruded polymer insulation was used on the bulk of the installed cables.

Table 5-4 provides the distribution of the insulation materials on these cables.

Table 5-4
25-kV to 35-kV Cable Insulation Materials

Insulation	Units	Percent of Reporting Units
EPR-black	7	9
EPR-brown	3	4
EPR-red	1	1
XLPE	2	3
PILC	4	5
Unknown	2	3

5.3.4 Shielding

Above 5-kV, cables are typically manufactured with insulation shields; however, 5-kV EPR cables may be manufactured and purchased with or without shields.

At 5-kV and above, XLPE cables have insulation shields. Excluding the general service cables, 22 units (30%) reported having a total of more than 271 circuits with unshielded EPR cables. Two plants reported having unshielded cables, but did not indicate the quantity. These cables were used in safety, fire protection, operationally important, station black-out, and off-site feed cables.

The lack of a shield on the EPR cables is not a reliability issue. Circuits without shield represent an electrical testing issue. Electrical testing at high voltage requires a uniform ground plane. An insulation shield provides such a ground plane. Circuits without a shield would not have a uniform ground plane and available electrical testing is unlikely to provide useful results.

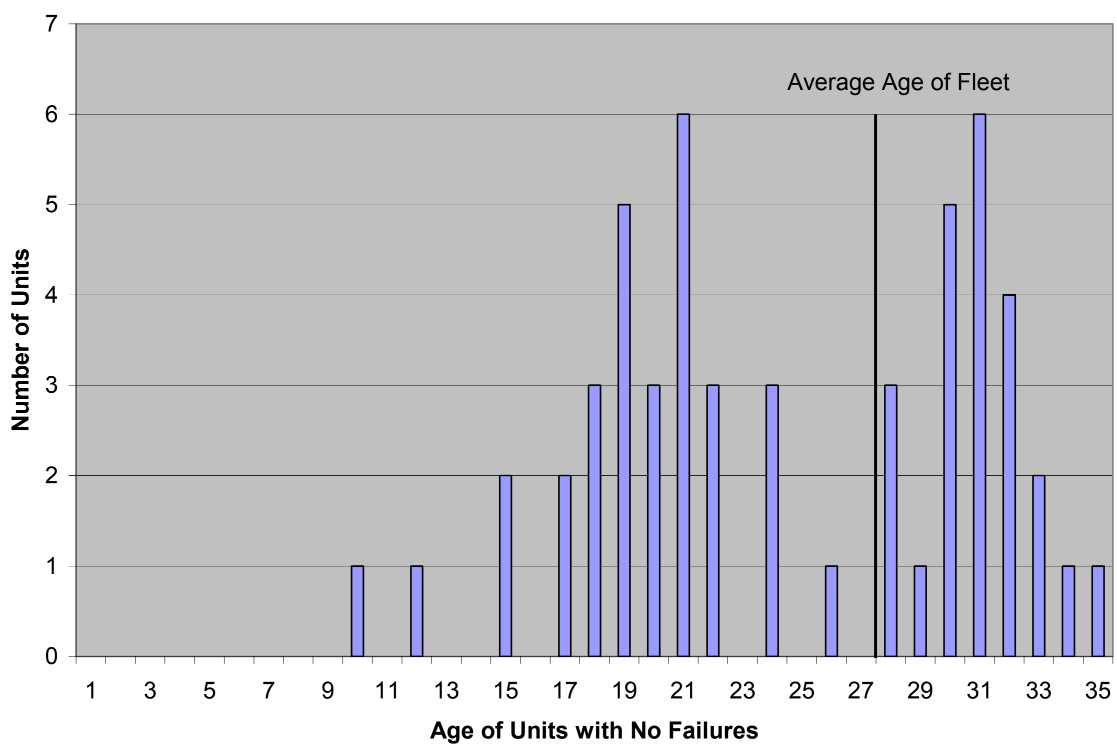
For the cables rated above 5-kV, nearly all of the cables were reported to have an insulation shield. A few entries indicated that the respondent did not know; 42 units reported having 5-kV cables with shields. This group with shields included all of the XLPE cables and a portion of the EPR cables.

5.3.5 Underground Wet Duty Failure Assessment

5.3.5.1 Plants with No Failures

Of the 74 units that provided data regarding failure experience, 53 units (72% of reporting units) had no failures of medium voltage, wet, underground cable to-date. Figure 5-2 shows the distribution of ages of the plants that have not experienced a failure. This Figure shows that 23 of the units with no failures that are older than the average age of the fleet; 30 are younger than the average. 19 units with no failures are 30 to 35 years old.

Figure 5-2
Age Distribution of Units with No Failures



5.3.5.2 Plants with Failures

Of the 74 reporting units, 21 units at 15 plants (28% of reporting units) experienced failures of medium voltage, wet or possibly wet, underground cable. The 21 units experienced a total of 50 failures in circuits that were safety-related, fire protection, off-site power, station blackout, or operationally important. General service cables were excluded when sufficient information was provided because these circuits are not related to safety or power production and are likely to be treated differently with respect to installation and operational practices. Events not related to the wet section of the cable were excluded from the analysis.

Cables that were replaced on the basis of test results or were replaced as an extended corrective action resulting from failure of a similar circuit were also excluded because they were replaced prior to failure.

Table 5-5 summarizes the number of failures per plant reporting failures. The Table indicates that the 6 plants with 3 or more failures account for 72% of the failures.

Table 5-5
Number of Failures per Plant Reporting Failures

Failures Per Plant	Plants Reporting Failures	Failures
1	4	4
2	5	10
3	1	3
4	2	8
5	1	5
10	2	20

Note: A parallel evaluation of related EPIX and NPRDS data indicates that the failures, reported by the 74 units responding to the NEI Survey, appear to be all of the medium voltage, wet cable failures that have occurred.

Figure 5-3 shows the distribution of the age of cables at time of failure for all cable types. The distribution of age at time of failure is quite broad with at little as 5 years and as many as 30 years of service before failure.

Figure 5-3
All Cable Failures

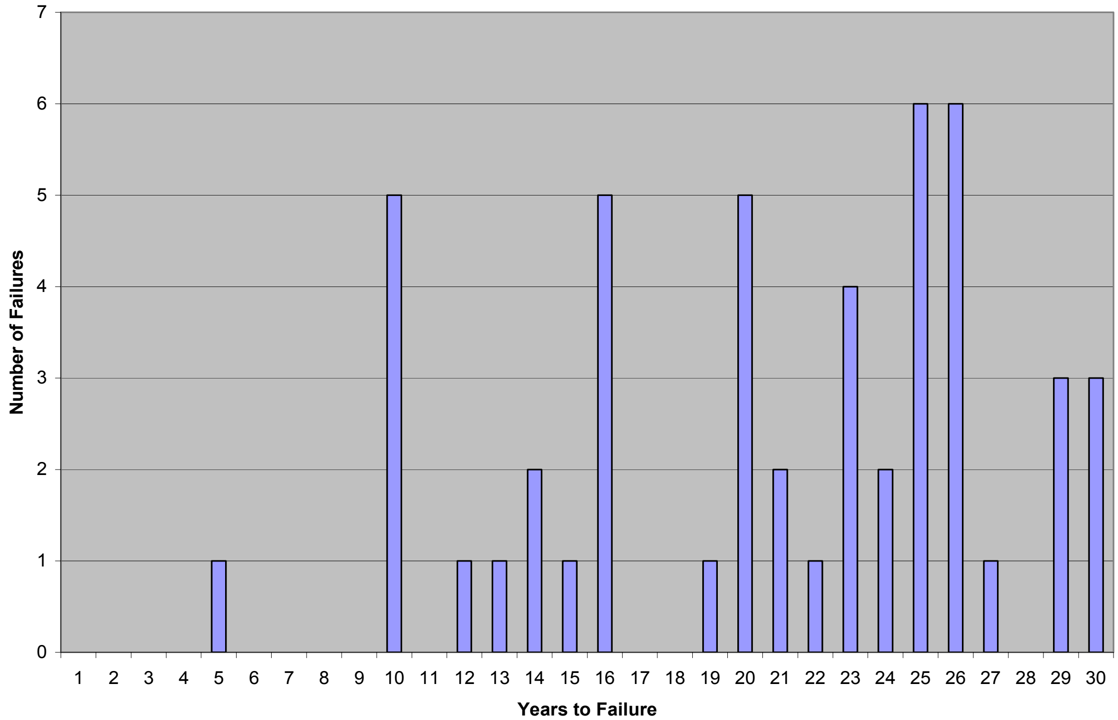


Figure 5-4 shows how the XLPE cable failures relate to the all failures distribution. The total distribution of failures is shown as gray bars with the XLPE failures shown in color. Twelve XLPE failures occurred at 4 plants. Eight of the failures occurred at one plant in a specific type of filled XLPE that was used only at that plant. These 8 failures represent 16% of the total wet, underground cable failures.

Figure 5-4
XLPE Cable Failures

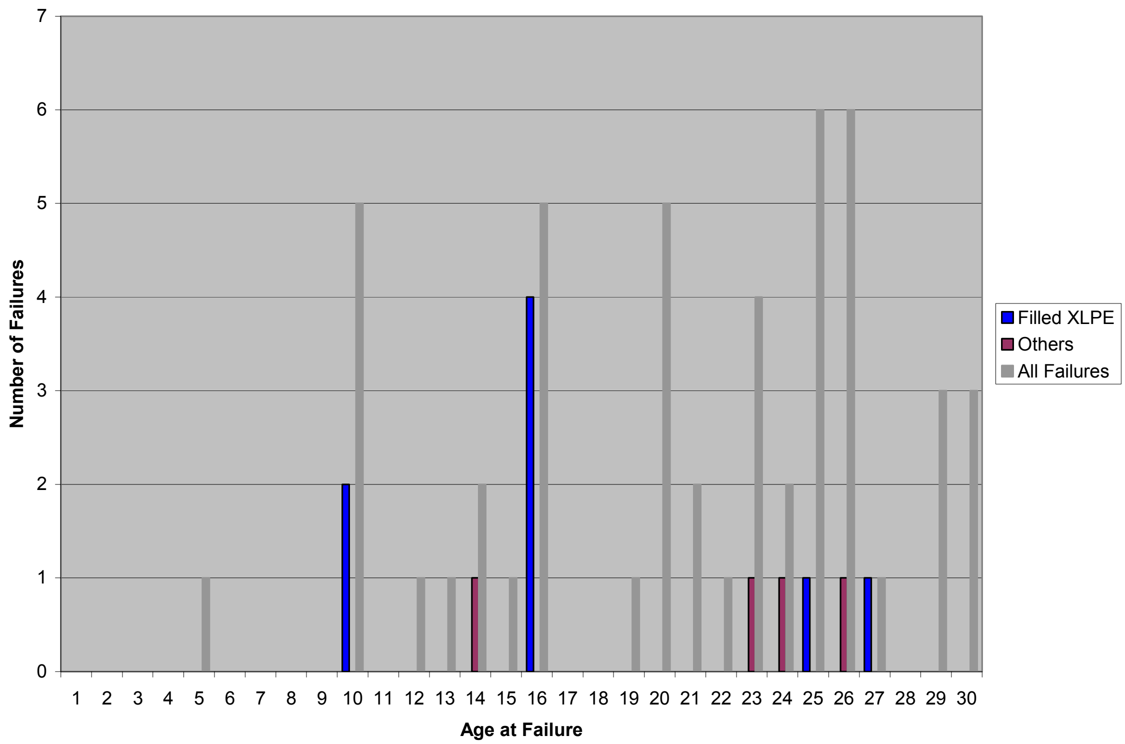


Figure 5-5 shows the distribution of EPR failures in relation to all failures. Black EPR is the dominant original insulation in the industry (88% of units reported usage). Red EPR was installed in units that became commercial in the 1980s and beyond; it has become the dominant replacement insulation. The failure of the red EPR at five years was determined to be related to a manufacturing flaw causing a large contaminant at the failure site. The three red EPR failures at ten years occurred at one plant; however, the cause of failure was not given.

Figure 5-5
EPR Cable Failures

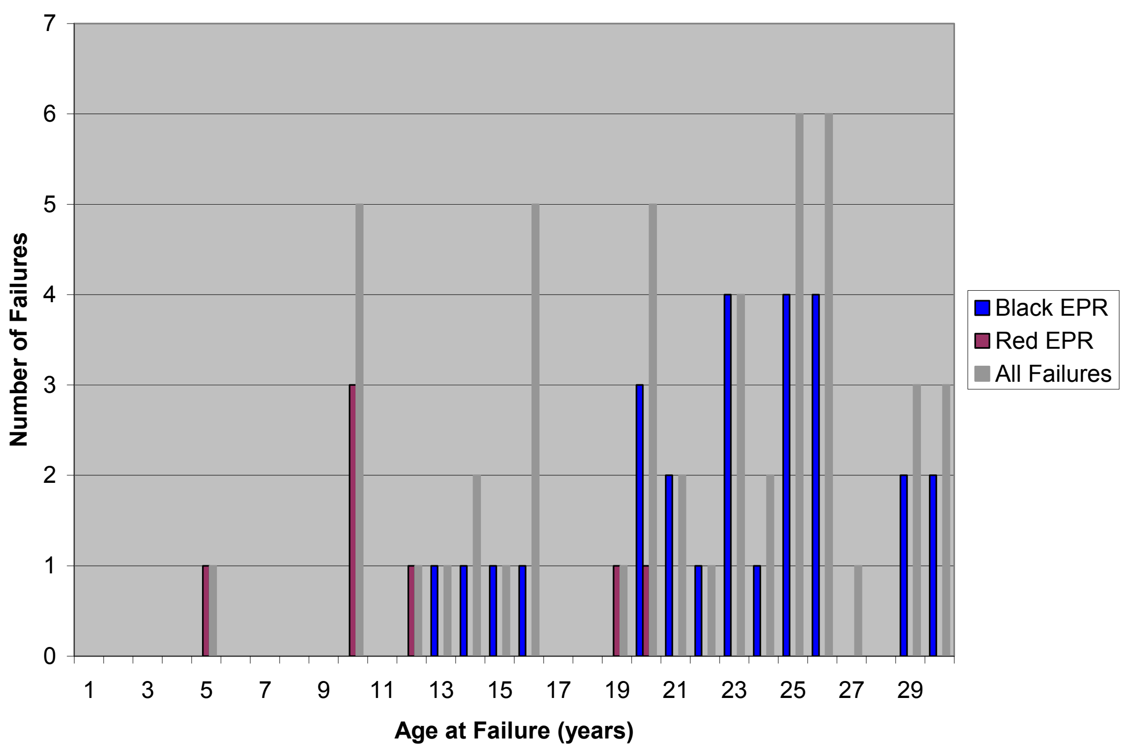


Figure 5-6 shows the relationship of the butyl rubber failures to the overall distribution of failures. While the number of butyl rubber failures appears small, only 4 of the reporting units indicated use of butyl rubber cables.

Figure 5-6
Butyl Rubber Cable Failures

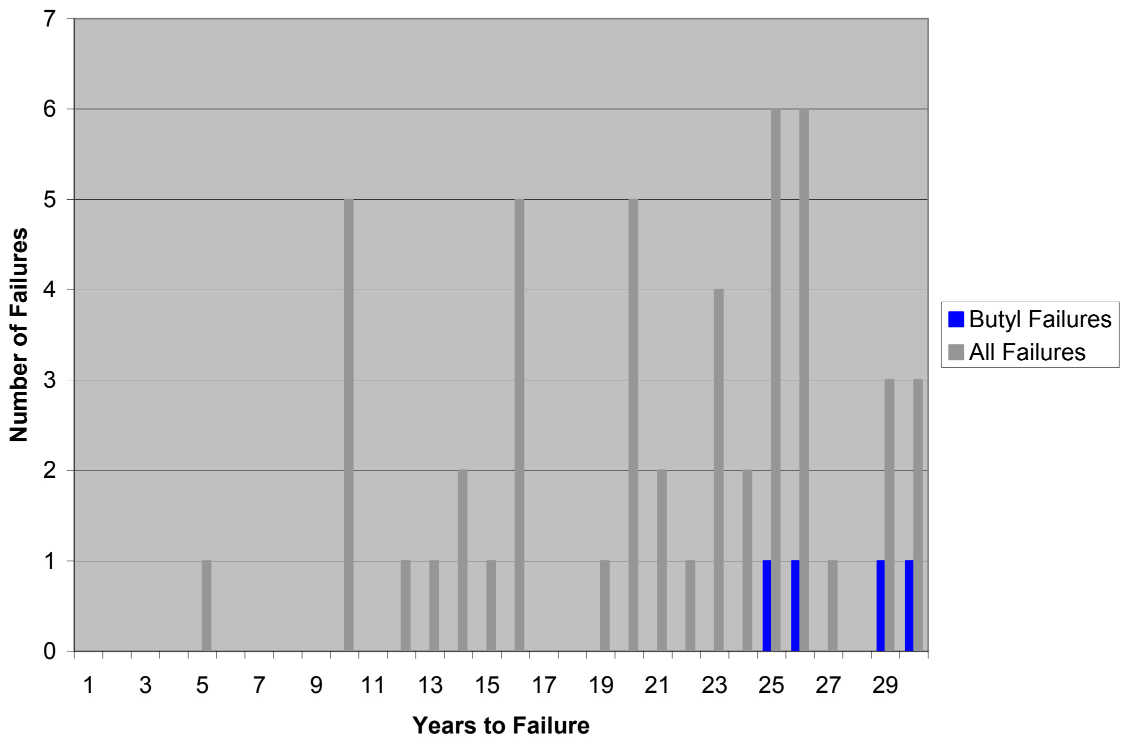


Figure 5-7 shows the age of the cables at the time of their failure. The general trend in the age at failure is increasing. The trend in the number of failures at a given age is relatively stable but showing a slight increase with time.

Figure 5-7
Age at Failure versus Year of Failure

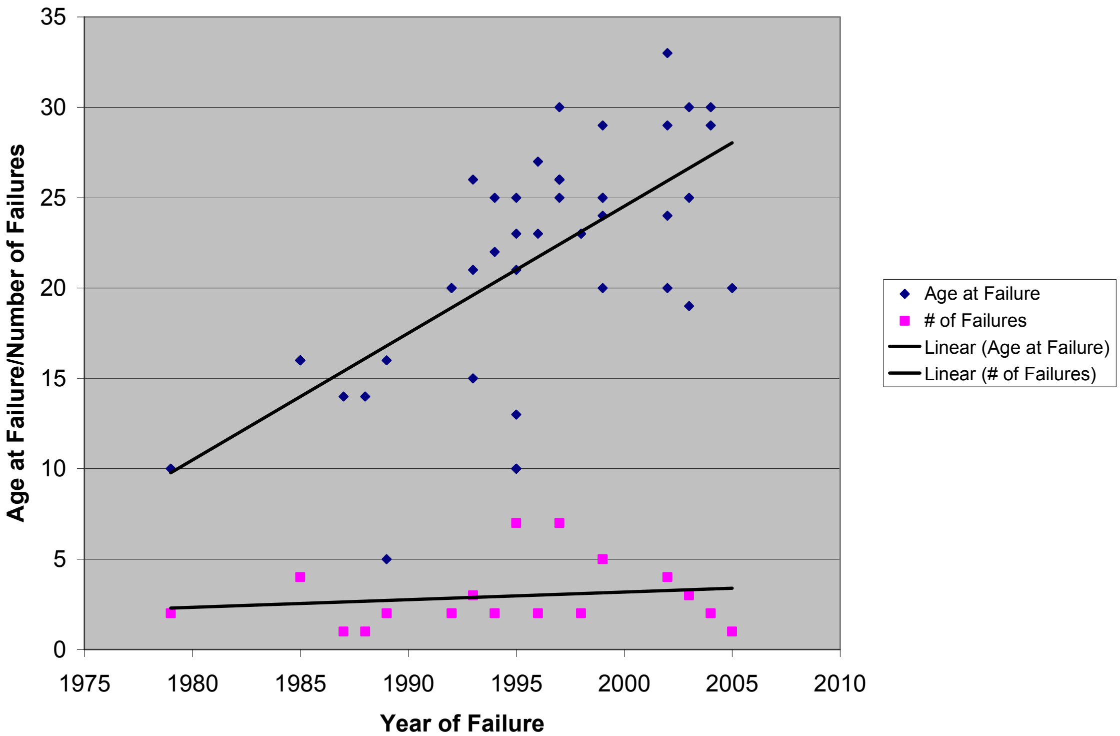


Figure 5-8 shows the distribution of age at failure versus year of failure for EPR cables. The trends for both black and red EPR are parallel with time to failure increasing. The population of black EPR cables is larger than that of red EPR cables. The first installations of red EPR cables occurred approximately 10 years after installation of black EPR cables began.

Figure 5-8
Age at Time of Failure for EPR Cables

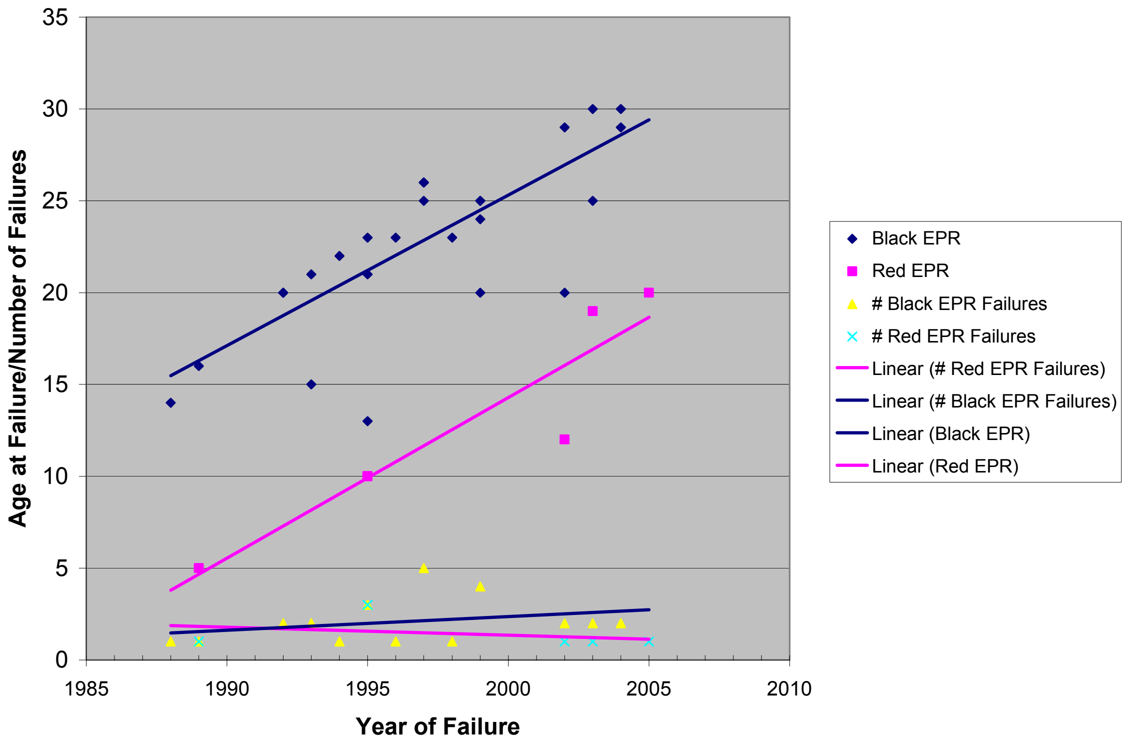
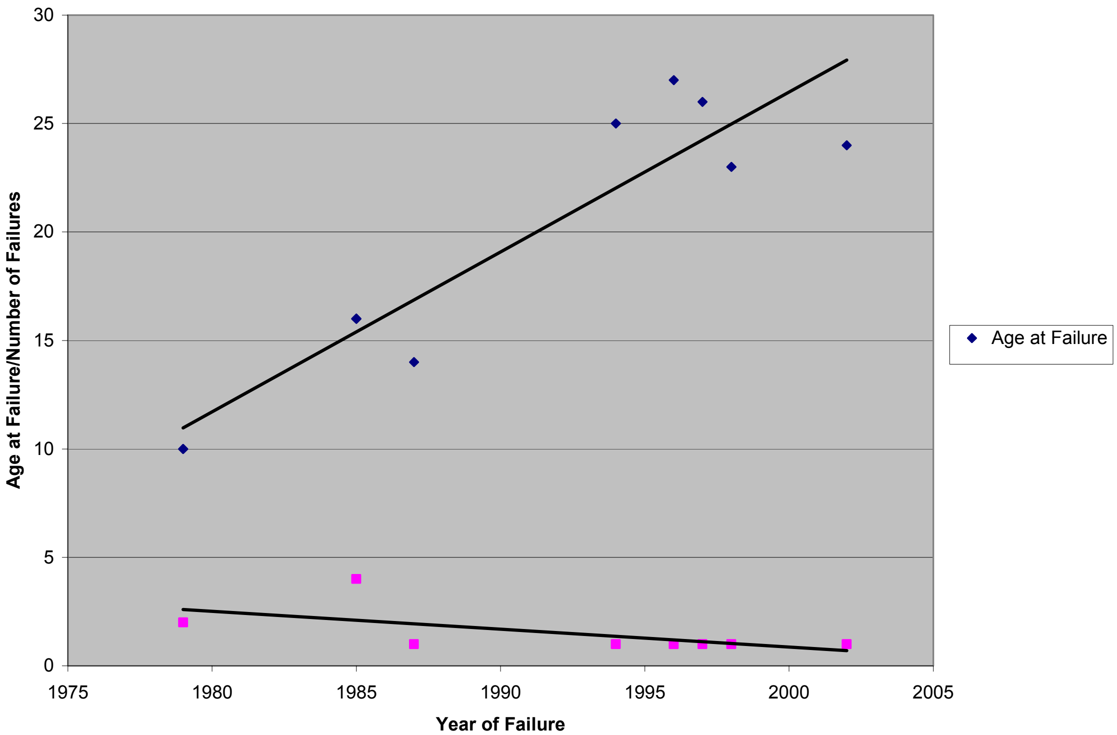


Figure 5-9 shows the distribution of age at failure versus year of failure for XLPE cables. The six failures through 1985 are of one unique filled XLPE insulation system at one plant. Failures after that point are a mix of the filled XLPE cables at the one plant and the non-filled XLPE cables at multiple plants.

Figure 5-9
Age at Time of Failure for XLPE Cables



5.3.6 Plant Actions in Response to Cable Failures

A few of the 15 plants reporting failures had a significant number of failures. Each of these plants has taken action to manage the issue.

- The plant with 10 failures of Okonite black EPR determined that the bulk of the problem was associated with manufacturing defects (inclusions in the insulation) and severe operating conditions. This plant has implemented a program of replacing the underground cables over a period of refueling outages.
- Another plant, having observed multiple failures of non-safety as well as safety related black EPR Anaconda Unishield cables, has implemented replacement of underground cables.
- The plant having nine failures of filled XLPE replaced the cable with a black EPR cable. The replacement cable had manufacturing problems and the plant has chosen to replace all of that cable with modern pink EPR cable.
- One of the plants that had XLPE failures performed laboratory failure assessments. Upon finding that a cable had degraded from water-treeing (previous failures were determined to be manufacturing defects), the plant implemented electrical testing (tan δ and hi-pot testing) to determine when other cables need to be replaced.

5.3.7 Inferred Failure Rate

As stated above, the average number of underground circuits per unit is 36 for the 81 units reporting. The population of units has been stable since 1990 at approximately 101. 40 of the failures occurred since that time. The approximate failure rate for wet underground cables during the period from 1990 to 2005 is 40 failures / (101 units x 36 circuits/unit x 15 years) or 0.00073 failures per year per circuit.

31 % of respondents indicated that their underground cables were dry. If the failures were considered to be associated with wetting only, (that is, making the assumption that dry circuits do not fail), then the failure rate for wet circuits would rise to 0.0011 failures per year per circuit (0.00073 / 0.69).

These failure rates are approximate at best and include a mixed population of safety, fire protection, off-site power, station black out, and operationally important cables. General application cables have been excluded from the set of failures when sufficient information was provided by the respondents.

5.3.8 Replacement Cables

Thirty units provided information on replacement cables in use. Nearly all of the remaining plants did not have failures and did not report on a replacement cable type. Table 5-6 summarizes the insulation types being used. Manufacturers have stopped making black EPR. While some replacements may have occurred from black EPR that was on site, all future EPR cable replacements are likely to be either red EPR or brown EPR cables. The dominant replacement material is red EPR, with a few plants using brown EPR or modern TR-XLPE cables.

Table 5-6
Replacement Cable Insulations

Insulation	Units
EPR (Type not indicated)	2
EPR-Black	3
EPR-Brown	5
EPR-Red	25
XLPE	4

5.3.9 Survey Summary

A summary of results drawn from analysis of the NEI Survey data appears below:

- 81 units provided information on the number of circuits in wet and dry applications
- 74 units provided information on installed cable types and whether failures had occurred or not.
- 53 units reported no failures of underground medium voltage cable.
- Of the 20 units having brown EPR (Kerite HTK), none had a failure of wet underground cable.
- The approximate failure rate for wet underground cables is between 0.00073 and 0.0011 failures per circuit per year.
- Of the 50 failures of wetted underground cables, 72% occurred at just six plants.

Table 5-7 provides a summary of the failures by material in comparison to the number of units reporting use of the material. The butyl cable population is small and a few events will distort the failure results. The black EPR population is large and has had a number of failures associated with manufacturing defects that, in conjunction with water-enhanced aging, led to early failures. The black EPR failures occurred at eight of the thirty-four units that reported using the material. One plant had 10 of the failures, indicating that the bulk of the units having black EPR are not experiencing a significant number of failures.

Both the pink and brown EPR cables are experiencing no significant level of failures. The brown EPR is an early material that has continued to be used through the present. The pink and brown EPR cables are the preferred replacement material and have been dominantly used in nuclear plants since the late 1970s and early 1980s.

XLPE insulation has experienced failures but in smaller proportion to that of related distribution cables that were operated at greater stress levels. The plants with multiple failures are monitoring or replacing their XLPE cables.

Table 5-7
Unit Population Failure Comparison by Insulation Type

Insulation Material	Number of Units with Material	Failures	Failures per Unit with Material
Butyl Rubber	3	2	0.67
EPR - Black	34	23	0.67
EPR - Pink	29	3	0.10
EPR - Brown	12	1	0.08
XLPE	12	17	1.42

Most of the EPR insulation failures were related to manufacturing defects, physical installation damage, or post-installation damage combined with wetting, indicating that early failure of wet EPR is related to a flaw rather than wetting alone. No wet failures of brown EPR have been identified to-date. (The one failure on a brown EPR circuit was related to a poorly made splice rather than failure of the insulation). Key insights from these two findings are that brown EPR insulation is not prone to early failure and, if no failures have occurred at a site in the first 35 or more years of operation, the installation was not subject to manufacturing or installation-induced flaws.

For XLPE, early failures have been recognized and this is the insulation system for which water-treeing is a concern; however, not all plants that have XLPE have reported failures. One of these is 32 years old.

5.4 SURVEY CONCLUSIONS

The trend in age at the time of failure has steadily increased as the fleet ages, indicating that early failures from manufacturing defects and installation damage are being eliminated from the fleet.

The trend in the number of failures is essentially flat and does not indicate that cable failure rates are increasing with time.

Impacts to plant operations to-date have generally been minimal, with cable replacements and cable material upgrades occurring on an as-needed basis.
A relatively small number of plants have had multiple failures of underground medium voltage circuits. These plants have taken appropriate action either by replacing potentially susceptible cables or by replacing cables based on electrical tests.

6 CABLE MANAGEMENT

6.1 SUSCEPTIBILITY OF MV INSULATIONS UNDERGROUND

Medium voltage cables in underground applications may be wetted for long periods. Some underground cables are actually dry because they are above the water table or because pumping keeps the duct system from accumulating water. Some plants have cables that were or are wet for long periods due to a lack of pumping or an inability to keep water from periodically accumulating and soaking the cable. Some plants have implemented pumping or improved automatic pump systems after cables had operated in a wet environment for an extended period. While the installed cables were manufactured for wet conditions, operating in a dry environment will increase the longevity of the insulation systems.

Wetting of energized medium voltage cable does accelerate the effect of aging. In nuclear plants with operating voltages between 4 kV and 13.8 kV, operating stresses under wet conditions are low. For early aging effects to occur, it is necessary to have an additional condition that causes the voltage stress to be locally enhanced. When they occurred, manufacturing defects or installation damage most often were the source of the additional stress. To-date, XLPE and black EPR have been more susceptible to stress related early aging effects, with XLPE being more susceptible to enhanced wet aging effects. Since the mid-1980s, manufacturers of all types of medium voltage cable have improved the cleanliness of their materials and the quality of their extrusions to eliminate manufacturing defects. Black EPR is no longer available and more water-enhanced aging-resistant pink EPR has been supplied from the 1980s forward. More recently, water-tree-retardant XLPE insulated cables have been made available.

In shielded power cables, the water trees can be formed by voltage stress across loosening gaps or other defects between the insulation and the two semiconductive shield electrodes. The helical wound semiconductive tapes for older insulation shields provided a higher likelihood of such voids. The post-1980 use of extruded insulation shields manufactured with finer contamination-filtering mesh screens has reduced these particular vulnerabilities in semi-conductive shields.

Underground medium voltage cables at nuclear plants may be installed in duct banks surrounded with concrete and hardened fill, in conduits embedded under concrete floors, in buried conduits, in concrete trenches with cable supports, and in a limited number of cases, direct-buried. When water migrates into these systems, the higher the concentration of ions from earth minerals or contaminants, the more conducive the environment for insulation water-tree formation and growth, or for contaminants to fill and expand voids within the insulation. When medium voltage cable is aged in a wet environment, it assumes the presence of continuous voltage. Also, if it is direct-buried in moist earth or submerged in muddy or salty water, then the degradation is faster than when it is in a relatively clean water immersion. For heavily loaded circuits, the moisture diffusion rate through the cable jacket and insulating materials is generally increased as the temperature of the wet environment increases because of load-current self-heating (i.e., ohmic heating).

The rate of water-enhanced aging may be reduced by preventing long-term submergence of continuously energized medium voltage cables by slope-draining conduits and by pumping out man-holes and trenches.

High operating temperatures (above 75°C for XLPE) from load-current self-heating or other sources can increase the overall water diffusion rate through jacket and insulation materials and can accelerate the propagation of water trees. As other factors contribute to selection of larger conductors than would be indicated by ampacity concerns alone, the self-heating factor usually has minimal impact on water-enhanced aging effects.

Installation stress (leading to mechanical damage to the jacket, shields, or insulation materials) increases susceptibility to water-induced degradation. If shields corrode, they can develop high-resistance localities or even corrode through to form divided sections. Such separated shield sections can lose their ground continuity and develop voltages that are hazardous to the underlying insulation screen as well as to personnel. One of the trade-offs for space-saving cable designs with reduced outer diameters, which have shield wires embedded within a combined semi-conductive insulation shield and jacket, is the designs' relative vulnerability to mechanical damage and hence their increased susceptibility to the moisture-voltage age stressor.

6.2 Differences Between Distribution and Nuclear Plant Issues

6.2.1 Market-Driven Differences

Since the distribution market is significantly larger than the plant cable market, most literature and research focus on the problems that have occurred in the distribution cable arena. The applications and nature of the cables used in each market are significantly different and determine failure types and mechanisms and tests that may be applied to the insulation systems. The circuits in distribution systems tend to be very long and branched to multiple loads. The limited numbers of circuits in plant applications tend to be relatively short and direct from source to single load. With the great number of circuits, insulation electrical loss is of greater consequence in distribution systems, resulting in the use of low-loss XLPE insulation. The short lengths of circuits in a power plant eliminate any concern about electrical loss and allow the use of longer-lived rubber insulations.

Since the distribution market used XLPE and encountered problems with water-tree-related failures, nearly all of the research literature concentrates on resolution of design and manufacturing issues. It is difficult to discern the applicability of much of the research and of the issues to EPR insulations. Some of the lessons learned in the resolution of XLPE degradation issues were applied to EPR cable design and manufacture. These include:

- Replacing carbon-filled cotton shield tapes with extruded semiconductors to prevent loose fibers from causing stress risers in the insulations;
- Improving the cleanliness of feedstock and the manufacturing process to eliminate contamination of the insulation; and

- Implementing a triple extrusion process that applies conductor shield, insulation, and insulation shield in a single pass.

Each of these steps improved the quality and longevity of the XLPE and EPR cables. Nonetheless, XLPE insulations still were prone to water-tree degradation at a much more rapid rate than EPR. Ultimately, a tree-retardant version of XLPE was developed, essentially making the material more like EPR in its behavior under electrical stress.

In addition to research on the resolution of the degradation mechanism for XLPE, electrical test methodology for XLPE advanced more rapidly than for EPR, because of the distribution market problems with installed XLPE. IEEE Standard 400 [Reference 15] describes test methodologies for XLPE and provides consensus acceptance criteria. Such clear guidance is not applicable for EPR cable. Due to the differences in the electrical behavior between TR-XLPE and XLPE, guidance is not available for testing TR-XLPE.

With regard to testing, distribution cable has a neutral layer that acts as an insulation shield because it is needed to provide a ground path for power, especially for single-phase feeders. In power plants with rubber insulated cables, 5 kV rated cable systems may not have an insulation shield. The lack of a shield affects the ability to perform electrical testing of the insulation in that there is no ground plane for testing. Higher-voltage sections of the medium voltage system have shielding. Most safety systems in nuclear plants operate at 4.16 kV, where an insulation shield is optional.

6.2.2 Distribution vs. Nuclear Plant Degradation

In general, nuclear plant cable systems are judged to be less susceptible to moisture-related degradation than similar systems in distribution service. This is due in large measure to their low electrical stress levels and to the use of rubber insulations, overall cable jackets, and duct bank systems and their well-shielded terminations.

The vast literature produced in response to moisture-related degradation in the distribution arena has been assessed as a valuable resource for nuclear utilities in understanding and evaluating moisture-related degradation in XLPE-insulated cables. It is less applicable to those stations that utilize rubber insulation systems.

The extensive use of rubber insulation systems made the numerous tests developed for the distribution market of marginal value to the majority of nuclear utilities. The lack of detailed knowledge regarding the degradation mechanisms of black and non-black rubber insulations exposed to long-term immersion remains a major impediment to the development of meaningful tests for this class of cables.

6.3 FAILURE MECHANISM DISCUSSION AND IMPACT ON RISK

Water-enhanced degradation does not cause direct breakdown of the XLPE or EPR, but rather reduces the dielectric strength of the insulation, eventually weakening the material to the point where it is susceptible to voltage surges that can initiate partial discharging. Partial discharging causes relatively rapid electrical degradation leading to an electrical tree and a faulted condition in weeks to months following inception. Instantaneous failure in the weakened condition would only be expected under transient electrical conditions such as a direct lightning strike. Most nuclear plant medium voltage circuits are not directly exposed to lightning strike conditions, given that the cables are either inside buildings or underground and not terminated to equipment exposed to lightning.

Tables 6-1 through 6-3 list the basic cable designs in use in nuclear plants by installation period.

Table 6-1
Early Cable Designs (1960s to 1970s)

Insulation	Conductor Shield	Insulation Shield	Jacket
Natural rubber	Cotton tape	Copper tape	PVC
Butyl rubber			Neoprene
Black EPR	Extruded semiconducting	Cotton tape with copper tape	Chlorinated polyethylene (CPE)
Black EPR	Extruded semiconducting	See jacket	Extruded semiconducting with copper wires in jacket
Gray EPR	Extruded semiconducting	None	Neoprene
XLPE	Extruded semiconducting	Extruded semiconducting with copper tape	PVC

Table 6-2
Intermediate Period Cables (Mid 1970s to Early 1980s)

Insulation	Conductor Shield	Insulation Shield	Jacket
Black EPR	Extruded semiconducting	Extruded semiconducting with copper tape	Chlorosulfonated polyethylene or Hypalon (CSPE)
Pink EPR	Extruded semiconducting	Extruded semiconducting with copper tape	CPE
Gray EPR	Extruded semiconducting	None	CSPE

Table 6-3
Late Cable Constructions (Mid 1980s to Present)

Insulation	Conductor Shield	Insulation Shield	Jacket
Pink EPR	Extruded semiconducting	Extruded semiconducting with copper tape	CSPE
Gray EPR	Extruded semiconducting	None	CSPE
Tree-Retardant XLPE	Extruded semiconducting	Extruded semiconducting with copper tape	CSPE

Medium voltage cables were specified and procured for wet and/or direct-buried or dry applications. Utilities required the cables to be satisfactory for wet conditions. Experience in the 1970s and 1980s with distribution cable (non-nuclear applications) indicated that some of the early designs were more susceptible to water-enhanced aging than expected. As previously discussed, research determined that some of the problems were related to cleanliness of polymer stock and quality of extrusion, which the manufacturers improved. Research also indicated that XLPE was subject to water-treeing. Manufacturers have now developed tree-retardant XLPE. Experience also indicated that black EPR was hydrophilic and more prone to water-enhanced aging, which led to its replacement with pink EPR that has clay fillers which are coated to preclude water absorption.

In addition to water-enhanced aging, medium voltage insulated cables have the same aging concerns as low-voltage cables. High operating temperatures and/or high radiation levels will harden the polymers (with the exception of butyl rubber that softens in high-radiation conditions). For medium voltage safety cables, the radiation conditions at their locations are below the threshold of concern for the insulation. Safety-related medium voltage cables are rarely used inside containment and radiation conditions in the remainder of the plant are below levels where significant damage would occur to the insulation. Thermal damage is possible if the local environment is hot or if cables have high ohmic heating. In general, safety-related medium voltage cables are either lightly loaded or unloaded during normal operation and there is no concern for ohmic heating. Operationally important cables[49] tend to operate under heavier, continuous loads; however, these loads should not exceed the cable rating. Depending upon plant design criteria, ohmic heating may or may not be of concern for operationally important cables. The insulation thicknesses in medium voltage cable used in 4 kV to 13 kV applications are large in proportion to the applied voltage. Under dry conditions, the voltage stress in medium voltage cables of the type used in nuclear plants is below the threshold where electrical degradation will occur. Only under long-term wetting will the insulation's dielectric strength decrease to the point where voltage stress can allow partial discharging, leading to ultimate breakdown of the insulation.

Medium voltage cables installed through the mid-1980s that are used for wet conditions will tend to experience aging effects more readily than originally expected. Wetting of cable insulation for medium voltage cable makes the insulation susceptible to long-term, potential (voltage) driven degradation. Different insulation materials and cable constructions affect the rate of age degradation and the type of degradation that can be expected. Some materials and constructions are expected to be nearly impervious to wet aging effects and some materials experience aging effects at a reasonably rapid rate (10 -20 years). Wet, energized XLPE degrades by means of development of water trees. The rate of aging degradation is enhanced by the number, size, and type of voids and inclusions in the insulation. Pure polymer with no voids or inclusions will be significantly less susceptible to wet aging effects and the growth of water trees. The importance of the quality of extrusion and the cleanliness of the polymer was recognized as the extruded insulation industry matured. EPR cable insulation aging degradation is most likely related to the tendency of fillers in the compound to absorb water. Those materials, such as black EPR that had poorly coated or uncoated clays which tended to absorb water, are subject to enhanced aging effects (again 10-20 years). Those materials, such as pink EPR that had coated clay fillers that preclude water absorption, are not expected to degrade rapidly or significantly in wet conditions. Brown EPR is less susceptible to electrically driven wet aging degradation because the material is purposely formulated to be lossy (i.e., conducts very slightly) such that electrical charges do not build locally within the insulation. This removes any concern for a trapped charge adding to the stress applied locally in the insulation, which could overstress the insulation and aid degradation. Black EPR was used in cables manufactured through the 1970s. Pink EPR was available in the late 1970s and replaced black EPR by the mid-1980s as an insulation material. Brown EPR has been available from the 1970s through the present.

Depending on the types of cables used in wet applications, the need and options for aging management vary. Electrical testing is possible for cables that have insulation shields. Electrical testing of cables without shields is currently not possible using standard industry-accepted methods. Table 6-4 shows approximate susceptibility to water-enhanced aging degradation versus electrical testability.

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[49] Operationally important cables are those whose failure would lead to loss or significant reduction of plant output.

Table 6-4
Water-Enhanced Aging versus Electrical Testability

Degree of Susceptibility / **Testability** V V V	**Most Susceptible**			**Least Susceptible**
Least Testable		Black EPR without shield	Gray EPR without shield	Pink EPR without shield
Most Testable	Early XLPE	Black EPR with shield		Pink EPR with shield; Tree-Retardant XLPE with shield

6.3.1 Common Mode Failure

The concern arising from common mode failure is that multiple equipment paths will fail simultaneously, such that a significant number of redundant paths are eliminated during the critical coping period of a design-basis accident. For a common mode failure to occur, a common stressor resulting from the accident environment or associated service conditions must be present that is intense enough to cause simultaneous or near simultaneous failure of multiple components. Such conditions do not exist for underground (wet) medium voltage cable.

The wet environment in and of itself does not cause cable failure. It eventually disturbs the potential distribution within the insulation, such that high potential is distributed across the remaining sound insulation, resulting in a significant reduction of dielectric strength. Such degradation makes the areas affected by water-enhanced environment more susceptible to voltage surges from lightning or switching. Most nuclear plant cable applications are shielded from lighting by having terminations within buildings and being located within the buildings or below grade. While a lower switching surge could affect medium voltage cables, these cables would have to be severely degraded. The surge would have to be high enough that a partial discharge occurs in the vicinity of the surface of the remaining insulation. The initial discharge is partial and does not breach the insulation. Each subsequent discharge causes a small increment of localized damage that is cumulative. Accordingly, the failure of the cable insulation is not instantaneous, but if severe switching surges continue, the cable may fail within months of the start of the partial discharging. The scenario for this type of failure is:

- Slow wet degradation of the cable polymer taking tens of years (20, 30, or significantly more) to make the cable susceptible to voltage surges[50]. The rate of degradation will be random depending on the local condition of the insulation (availability of an initiation site, which is generally an inclusion at the conductor side of the insulation, containing an ionizable chemical, and the size of the inclusion).
- Susceptibility to a randomly occurring voltage surge. The surge must be severe enough to initiate an electrical tree. Not all surges will be severe enough to start an electrical tree, even in insulation with advanced wet degradation.
- Relatively rapid electrical degradation (weeks to months) leading to electrical breakdown (failure) of the insulation, once the electrical tree has initiated.

Each of these aging periods or events has a random nature. The slow wet degradation has a random rate depending on local conditions at the site. Thus, the likelihood is very low that multiple cables or multiple phases in the same cable will all achieve the same level of susceptibility to electrical surges at the same time. The surge voltages that may occur vary from slightly higher than operating voltage to approximately double voltage. Depending on the source of the surge in the electrical system, different cables within the system will experience different surge levels due to impedances within the electrical system; therefore, not all cables within an electrical system will experience the same level of surge. Even if two electrical trees started at the same time, the rate of their growth is not constant but also random. Given that each of the aging mechanisms and events leading to electrical failure is random, the likelihood of simultaneous cable insulation failures is extremely low.

A key NRC assertion is that a severe voltage surge associated with a design-basis event, coupled with a loss of offsite power, will cause failures during the initial coping period (e.g., hours to one day). The nature of the medium voltage cable failure mechanisms is that even if a severe voltage surge occurs at the outset of the accident (in the first few minutes), there is no mechanism that leads to immediate failure. Rather the failures, assuming electrical trees initiated in multiple circuits, would occur weeks to months after the event and not in the first hours or days. If electrical trees were to occur, failures would likely occur as separate events at least a number of weeks after the surge at the start of the event and would not have any significance with respect to core melt or early offsite release.

The above discussion assumes that multiple safety-related cables, having insulation susceptible to a wet environment, exist in a plant and have been energized and wet for a long period. Not all plants have safety-related cables that are wet and most plants have a very limited population of medium voltage safety-related cables that are wet. In addition, assessment of failure data indicates that significant manufacturing defects or installation damages need to be present for early failure of medium voltage underground cables. Such defects are relatively uncommon and are also random. In addition, most cables in safety-related applications are normally de-energized, thereby avoiding a key aging mechanism.

[50] Current surges on the conductor do not cause transition to partial discharge. The surge has to place elevated potential (voltage) across the insulation.

6.4 CABLE MANAGEMENT PROGRAM

6.4.1 Program Phases

The key steps within a typical MVU Cable program include the following:

- Documenting failure history
- Determining root causes of failures
- Evaluating trends
- Sharing insights
- Assigning priority
- Verifying replacement capabilities
- Resolving failures
- Monitoring performance
- Trending

Note: Priorities can be determined by using INPO AP-913, Rev. 1, *Equipment Reliability Process Description* [Reference 31].

6.4.2 Cable Replacement

Failures are infrequent and most of the cables that have failed were installed as part of original construction. Given that no or few failures have occurred to-date, some sites may have lost the capability to quickly replace cables because they have not had to replace them and/or the division of their company that would have performed the work has become part of a separate corporation. In addition, replacement cable may not be readily available in plant warehouse inventory or vendor inventories. Use of remaining inventory from the 1970s through mid-1980's (types XLPE, black EPR, etc.) should be used with caution as replacement cable, since significant strides in cable construction have occurred.

Should a failure occur, obtaining replacement cable may delay cable replacement for several weeks unless repair contingencies are already in place. Review of contingency procedures for obtaining and installing new cable is highly recommended. In addition, careful removal of the failed cable and a formal root-cause investigation using a competent laboratory is highly recommended to determine the significance of the failure with respect to the remaining installed cable of similar construction and age.

6.4.2.1 Cable Selection - Voltage Rating

Nominal cable AC phase-to-phase voltage ratings established by the ICEA/NEMA industry standards provide an inherent margin above system voltage ratings:

- 5 kV cable vs. 4.16 kV systems;
- 8 kV cable vs. 6.9 kV systems;
- 15 kV cable vs. 13.8 kV systems; and
- 25 kV vs. 19 kV systems.

Similar margins exist for the few higher-kV systems considered as medium voltage.

Within these nominal ratings, users can specify increased insulation levels corresponding to discrete increases in the insulation thickness for that particular rating and insulation material, allowing further opportunity for increasing that rating-to-system voltage margin. For example, per NEMA WC8 [Reference 32] manufacturers standard, 15 kV shielded EPR insulated cables have an insulation thickness of 175 mils for the 100% insulation level, 220 mils for the 133% level, and 260 mils for the least common 173% level (though the manufacturer can dictate a different requirement at that level). Although the utility user may have other reasons for insulation level choice, such as adding conservatism, the ICEA/NEMA guidance is primarily dependent on whether over-voltages of various durations are possible due to an impedance-grounded or un-grounded system not immediately clearing ground faults.

At the 5 kV cable rating (4.16 kV plant systems rating), utilities may choose whether to have each conductor's insulation shielded, as long as certain ICEA/NEMA manufacturing standards stipulations are met. Shielding examples include a discharge resisting jacket or metallic armor. The same standards require insulation shielding for systems intended to operate at system three-phase voltages above 5 kV. Thus, both shielded and un-shielded insulations are used in 5 kV-rated cables in nuclear power plants.

The 4.16 kV systems are much less likely to degrade than the two higher ratings because the moisture voltage age stressor and water-tree formation are reduced. Those insulated conductors that are un-shielded cannot be diagnostically tested due to the lack of an outer coaxial ground plane. They also do not benefit from a shield's containment of the cable's electric field within the insulation, its reduction of electromagnetic and radio-frequency interference effects, or its reduced potential external shock hazard.

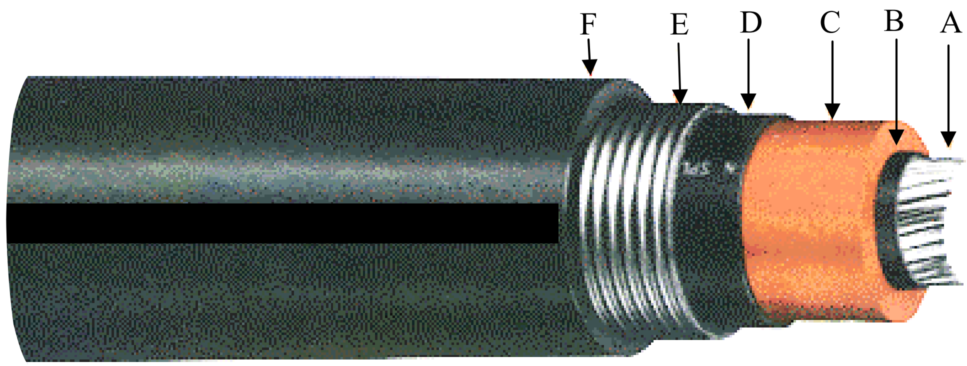
Most power cables have a base impulse insulation level (BIL) capability comparable to that of other electrical equipment with similar voltage ratings. Cable insulation must be able to withstand brief voltage spikes from switching inductive loads, such as motors, without electrical breakdown or inception of partial discharging. Cables are designed and manufactured to have a high BIL throughout their operating life.

6.4.2.2 Cable Selection - Type

Susceptibility of medium voltage cable to underground environments and constraints of the existing tray, duct, and conduit system may limit cable replacement options unless a totally new system is being installed. If the ducts or conduits were sized for compact diameter configurations, replacement options would be limited to cable constructions that can be pulled into and will fit within existing conduits and ducts. Cable inventories remaining from the early 1970s are not recommended for use as replacements. Modern moisture aging-resistant insulation should be used (TR-XLPE or pink or brown EPR).

Manufacturers have developed moisture-impervious cable designs that should fit within the size constraints of most cable ducts and conduits. They are similar in cost to cables that are not moisture-impervious. In Figure 6-1 below, item E is the moisture barrier, which may be copper or lead. In this case, it is copper with a sealed overlap that prevents moisture from affecting the insulation. The copper layer also completes the shield system. Use of such replacement cables would eliminate the concern for water-related degradation of medium voltage cables. These cables are specifically designed for underground applications in ducts or direct burial where they are subject to excessive water.

Figure 6-1
Moisture-Impervious Medium Voltage Cable Configuration



A - conductor; B – semicon conductor shield; C - insulation; D – semicon insulation shield; E – metallic moisture barrier; F -– jacket

6.5 ONGOING FAILURE DATA TRENDING

6.5.1 Failure Data Template

The NEI Task Force recommends using a MVU Cable Failure Data Template for consistent reporting of any failures in OE reports. This information would have detail similar to that collected in the MVU Cable industry survey.

6.5.2 Failure Data to Collect

A successful cable management program will contain a process that collects appropriate data. Data management will be dependent upon the following data:

- Circuit numbers (or number of circuits)
- Rated and applied voltage levels
- Cable manufacturer, insulation type, and color
- Cable age (based on year installed)
- Cable functions
- Cable conductor shield attributes and insulation shield attributes
- Root cause
- Cable replacement description

6.5.3 Sharing Failure Data

For recovery of historical MVU cable failures, central databases are required. Initially, the MVU Cable Task Force collected the data. If negotiations with INPO are successful, the MVU cable failures will reside with INPO and be recoverable in their NPRDS and EPIX systems.

6.6 GRADED APPROACH FOR MONITORING AND REPLACEMENT

Many MVU cable installation circuits do not power loads that are safety-related or important to safety or even important to generation. Thus, a graded approach in cable monitoring and replacement strategies is best for safety and business reasons. INPO AP-913, Equipment Reliability Process Description [Reference 31], provides guidance for such a strategy.

While most attention to application of INPO AP-913 is related to active component analysis and program outputs, such as active component preventive maintenance frequency, the same methods can be applied to passive components, as stated several times in the document. This would mean a cable connected to an “AP-913-critical” active component should also be considered a critical cable circuit and treated appropriately. On the other hand, other less-important cables connected to less-important loads could be “run-to-failure” without any safety consequences.

7 RESEARCH RESULTS

7.1 TREEING TENDENCIES

Water trees can form in all extruded solid dielectric materials, including XLPE and EPR insulations. Water trees are generally observed as a dendritic[51] pattern of water-filled micro-cavities in a polymer [Reference 2] that form when exposed to moisture in conjunction with a sufficient electrical stress for a significant period. When severe water-treeing has occurred, the electrical strength of the insulation is reduced, ultimately leading to electrical failure of the insulation. As described below, materials that are hydrophobic, such as XLPE, have a much higher tendency for growth of water trees than those that are hydrophilic, such as EPR. Existing data indicates that water-treeing-related failures are not common in EPR insulation and that other deterioration mechanisms related to external environments (e.g., chemical contamination) or manufacturing flaws have caused failures to-date rather than a generic aging mechanism such as water-enhanced aging.

Reference 2 discusses water-treeing of cable insulations and its relative importance with respect to loss of dielectric strength of the insulations. This paper indicates two processes associated with water-tree growth: electrochemical and electromechanical. Under high stress conditions, electrochemical effects at the tip of the tree weaken the polymer to the point that the electromechanical forces cause a sudden yield of the polymer and an extension of the tree in the range of 0.01 to 0.1 μm. Relatively little electrochemical damage is necessary to allow the high electromechanical stress, as used in laboratory experiments employing energized needle tips, to propagate the tree. In lower-stress conditions that occur in actual applications, substantial electrochemical degradation is required before the yield stress of the polymer is reduced to the point that the water tree can extend itself.

Two water-tree types exist: vented and bow-tie. The vented water tree extends from a surface of the insulation into the material. The bow-tie tree starts at a void or contaminant in the polymer and extends in both directions in line with the electric field.

Table 7-1 provides an indication of the relative tendency for XLPE, filled XLPE, and EPR insulations to grow water trees. XLPE has ninety-three times the density of bow-tie trees and thirty times the density of vented trees compared to EPR under the same wet-aging regimen (three times rated voltage for eight months). Of the two, vented trees are of more concern because water from the external environment can continuously re-supply ionic impurities that can support continued tree propagation. The data in Table 7-1 support the position that EPR insulation is much less likely to deteriorate from water-treeing than XLPE insulation and aging in water is much less severe for EPR insulation. It should be noted that the XLPE insulation had only 1/6th of the water absorption of the EPR insulation. Accordingly, water absorption alone is not directly related to the tendency to grow water trees.

[51] Branching like a tree.

Table 7-1
Bow-tie and Vented Tree Density in Insulation Materials

(Reference 2, Tables II and III)

Material	Bow-Tie Density (mm^{-3})	Bow-Tie Length (μm)	Water Absorption (ppm)	Vented Tree Density (mm^{-3})	Vented Tree Length (μm)
XLPE	>28	90	33	0.3	60±40
Filled XLPE	4	180	>180	0.2	120±50
Filled EPR	0.3	390	>180	0.01	45

Note: Low densities in EPR are real and not due to lack of transparency.

Reference 3 states "EPR insulation has several attractive features:

- Corona resistance
- Wet electrical stability
- Water tree resistance
- High temperature performance
- Flexibility"

Reference 2 describes the reason why EPR insulation is more resistant to water-enhanced aging than XLPE insulation. EPR insulation's alternating current breakdown strength decreases significantly at the onset of water-enhanced aging and then stabilizes; however, its impulse breakdown strength remains high. TR-XLPE insulation, on the other hand, maintains its AC breakdown strength but has a significant drop in impulse strength when wet-aged. The key difference is that with EPR the absorption of water and its effect on the breakdown strength of the material are uniform throughout the insulation, such that the voltage stress is uniform. In the presence of voltage surges, EPR that has absorbed water during its life is uniformly stressed by the surge, such that surge breakdown strength remains high. In XLPE, the dielectric strength of the material is high, but at the sites of water trees the stress distribution in the insulation is greatly disturbed, leading to very high localized stress conditions. When a surge occurs, these localized stress conditions can lead to breakdown, especially when the water-tree population is high and the water trees have grown to significant lengths. Accordingly, EPR simply does not form trees as readily or in the same manner as XLPE.

7.2 ACCELERATED AGING OF MODERN EPR INSULATIONS

EPRI 1003664 [Reference 7] evaluated modern EPR insulations and TR-XLPE insulation under accelerated field and laboratory conditions. In the field, cables were aged at normal voltages in the first case and at 2.5Vo[52] in the second case. The laboratory aging was performed submerged at 2.5Vo. The bath was kept at temperatures similar to that of the monitored temperature of the field specimens.

The five EPR cables and one TR-XLPE 15 kV rated cable had similar designs. A different manufacturer made each cable during the 1994 -1995 time frame. The nominal construction was 107 mm^2 (4/0 AWG), 19-strand compressed copper conductor, 0.38 mm extruded semiconducting conductor shield, 4.45 mm (175 mils) EPR or TR-XLPE insulation, 0.75 mm extruded semiconducting shield, and 20 - 5.25 mm^2 (10 AWG) tin-coated copper concentric neutrals. These cables did not have overall jackets, as would be commonly used in nuclear applications. In addition, these 15 kV cables have higher operating voltage stresses than would occur in 5 kV or 8 kV rated cables. These cables have 4.45 mm of insulation and operate at 8 kV phase to ground. Cables in 4160 V applications have 3.56 mm (140 mils) and operate at 2.4 kV phase to ground. The 15 kV rated cables operate at 1800 V/mm (71 V/mil) and 5 kV cables operate at 675 V/mm (27 V/mil). Accordingly, the results described here with respect to insulation capability are very conservative when applied to 5 kV-rated cables.

The EPR insulations included those currently in common use as replacement cables in nuclear power plants.[53] The cables were purchased through a utility. The manufacturers were unaware that the cable was to be used in a research program. Approximately 3,000 meters (10,000 feet) of each cable type were acquired for the program.

Each of the laboratory specimens consisted of a 27.5 m coil placed horizontally in a water-filled tank. Each tank had 10 coils. Water was also placed in the conductor interstices. As previously stated, the temperature of the water bath was controlled to reflect temperatures similar to those monitored at the field site operating at 2.5Vo. The applied voltage was 20 kV, which is approximately 2.5 times that of phase-to-ground voltage (8 kV) on a 13.8 kV circuit. Twice a month impulse surges of 1.5 x 50 μs [80 kV] were applied to simulate lightning and switching surges that could occur under actual conditions. For the field-installed specimens, temperature of the earth, cable, and conduit were measured. Phase voltages and currents were continuously monitored. Events such as sags, swells, and impulses were monitored along with the time of the event. Two major events were recorded: a lightning arrestor failure and a snow plow striking the associated transformer pole. (Note: Most nuclear plant cables are not subject to either of these events given that they are terminated within well-shielded buildings and do not have aerial runs.)

[52] Vo is phase to ground voltage.
[53] Okonite, Kerite, and BICC General Cable specimens were included in the 6 cable types tested.

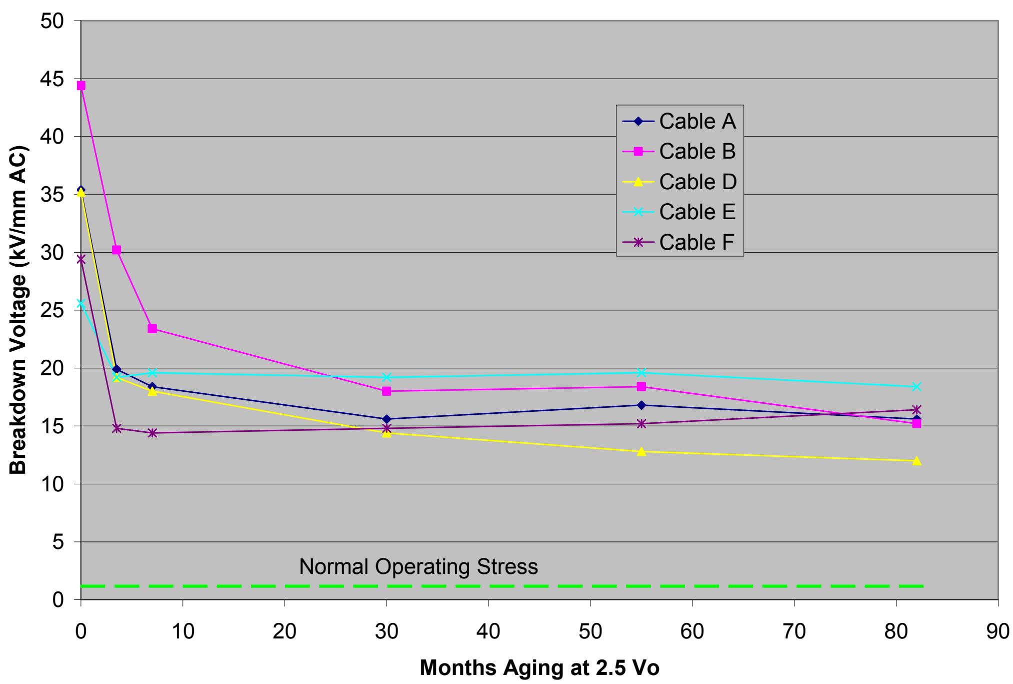
7.3 LONGEVITY UNDER TEST CONDITIONS

The entire group of field-aged cable (both one times Vo (1 Vo) and 2.5 times Vo (2.5 Vo)) functioned through the entire 82-month (6.8 year) period without failure. One EPR insulated cable type that is not used in nuclear applications failed six times in the laboratory exposure. The failures appeared to be from localized imperfections. The remaining laboratory specimens sustained no failures.

7.3.1 Breakdown Voltages

Figure 7-1 shows the change in breakdown voltage for the laboratory-aged cables. After the initial drop, the breakdown voltages stabilized and remained essentially constant during the exposure for cables A, E, and F, while cables B and D showed a slight continued decreasing trend. The figure is presented in terms of kV/mm AC. The normal stress level is between 1/4th and 1/6th of the breakdown voltages that the specimens exhibited for the bulk of the exposure. Cable E retained the highest breakdown strength for EPR cables. (Cable C is the TR-XLPE cable and its data is not shown in the figure.)

Figure 7-1
EPR Steady Voltage Breakdown Testing (Wet) at 2.5Vo (20 kV)



Note: In addition to 2.5Vo, 80 kV (1.2 x 50 µs) impulses were applied to the laboratory aged specimens twice a month to simulate lightning and switching surges.

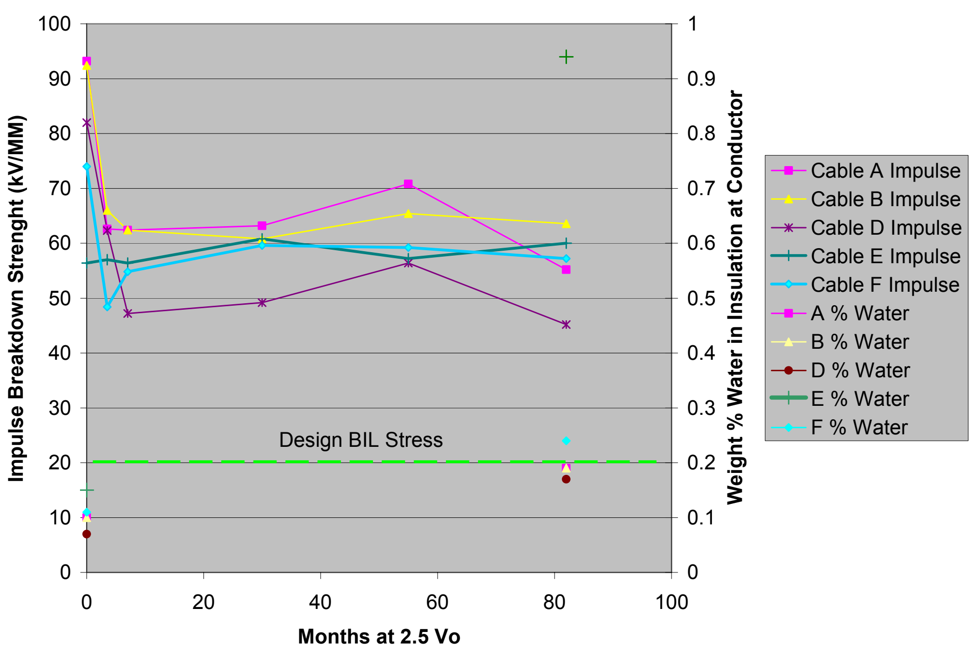
For the field test specimens, all of the cables except B and E exhibited less than 5 pC partial discharge at voltages up to 35 kV AC. Cable B exhibited 100 pC at the 75-month aging point, which was found to be associated with pitting on the insulation shield on a nine-meter section of the cable. At 20 kV, cable E exhibited 5 pC when tested between 26 to 84 months. At 35 kV, cable E exhibited between 15 and 25 pC when tested between 26 and 84 months. It should be noted that these partial discharge results do not appear to indicate a significant problem for this particular EPR insulation, in that its breakdown strength was the highest of all of the insulations as shown in Figure 7-1.

For the laboratory-aged specimens, all cables except cable E had partial discharges that were less than 5 pC throughout the entire 82-month program, with a test voltage of 35 kV AC. Cable E had 5 pC during the entire period.

7.3.2 Impulse Breakdown Voltage

Figure 7-2 presents the impulse breakdown voltages for the laboratory specimens during the course of the exposure. As with the breakdown voltages, the impulse breakdown voltages initially dropped and then stabilized for the duration of the test. The figure also shows the weight percent of water in the insulation at the start and end of the test program.

Figure 7-2
EPR Impulse Voltage Breakdown Testing (Wet) at 2.5Vo (20 kV)
(63% Probability form Weibull Distributions)



7.3.3 Tan δ Measurements

Figures 7-3 and 7-4 represent the tan δ (dissipation factor) results for cables A and E respectively, two of the EPR insulations. Results for cables B, D, and F were similar to those of cable A. The cable E polymer design has purposefully "lossy" features i.e. to prevent charge buildup within the polymer. The significantly higher tan δ results are representative of this design difference. For all of the cables, there is no discernable aging trend indicated by the results.

Figure 7-3
EPR 'A' Dissipation Factor Laboratory Testing (Wet) at 2.5 Vo and 60 hz

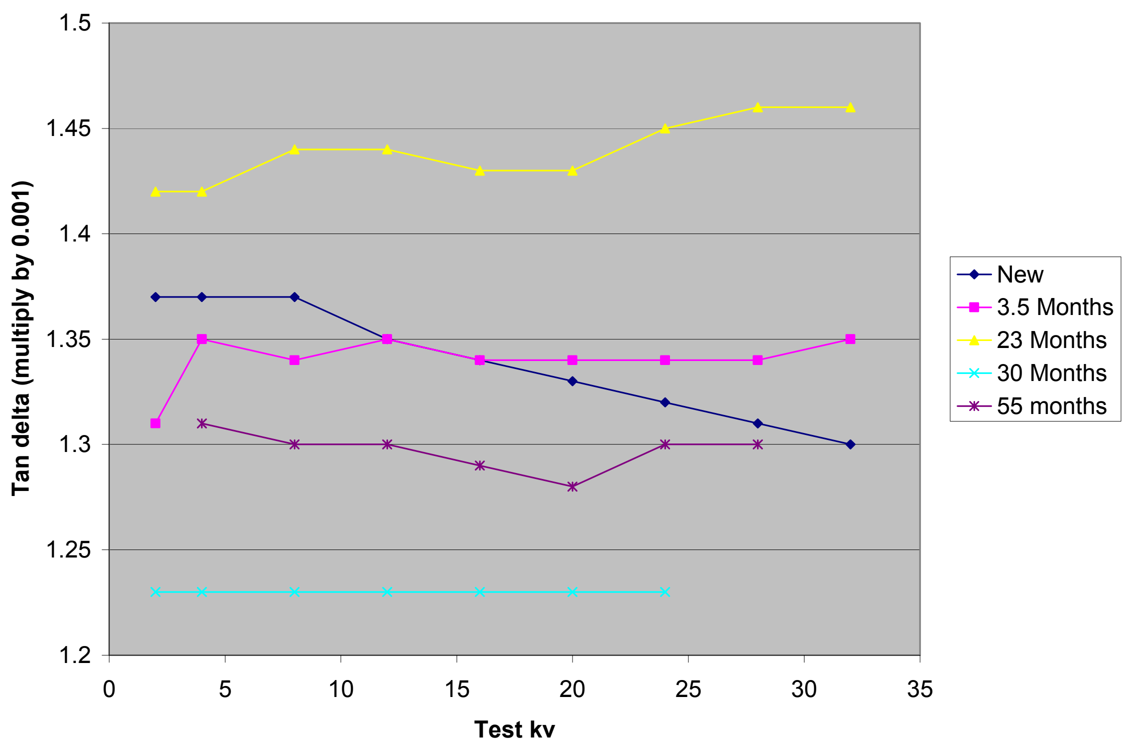
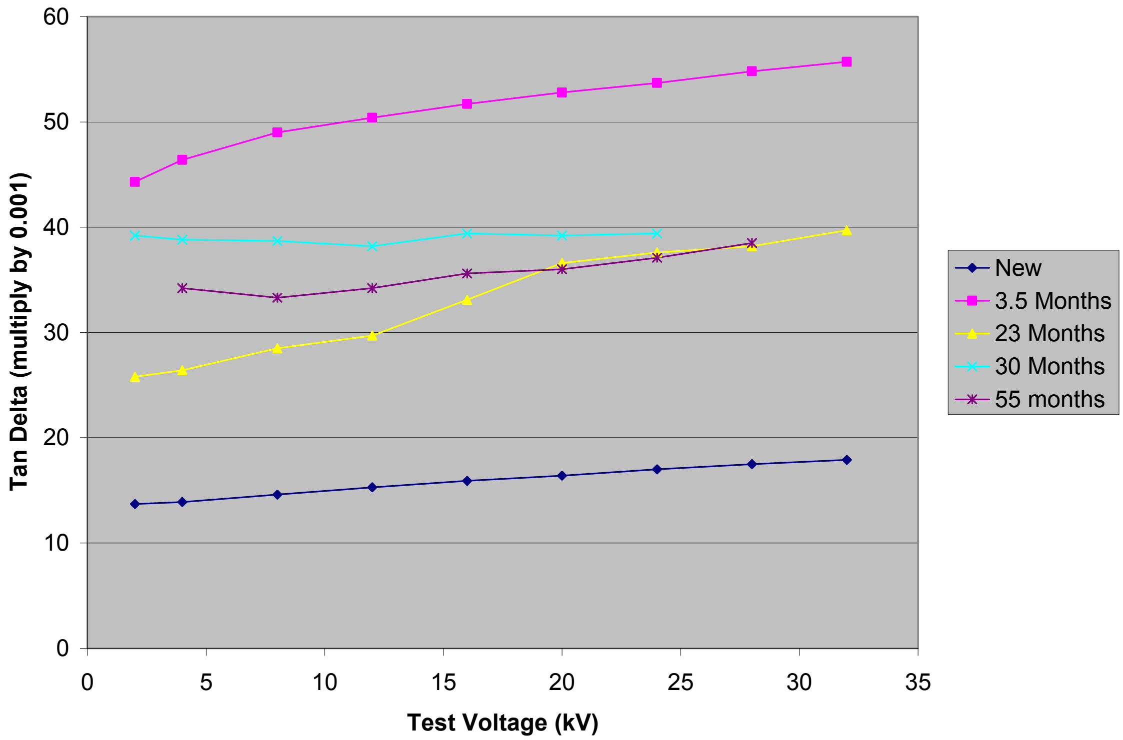


Figure 7-4
EPR Cable 'E' Dissipation Factor Laboratory Testing (Wet) at 2.5Vo and 60 hz



7.4 EPR Test Conclusions

These tests indicated that under accelerated conditions, the EPR insulation used in replacement cables functioned well and maintained adequate electrical properties. Even continuous wet age testing at 2.5 times voltage did not result in early failure. The AC breakdown and impulse breakdown remained well in excess of the levels required for service. The tests indicate that long life can be expected from these insulations even in the presence of moisture. In addition, the test results indicate that tan δ (dissipation factor) measurement is not likely to be useful for EPR insulation even though it is useful for evaluating XLPE insulation. With the exception of cable E, the cables did not have partial discharge levels of significance. Nonetheless, the partial discharging of cable E in the field-aged cables did not correlate to a significant change in impulse or AC breakdown strength.

The test program provides a strong indication that modern EPR insulation configurations in use in nuclear plants will have long satisfactory service lives even when subject to wet conditions. It should be noted that the test specimens did not have jackets. Nuclear plant cables have jackets that would further aid in reduction of water migration into the cable insulations.

7.4.1 Research Results from Black EPR

Very limited research data is available for black EPR, which was used by many rubber-insulated cable manufacturers for medium voltage cable in the early 1970s. EPRI 1009017 [Reference 8] evaluated the extension of service life of black EPR-insulated cables by injecting insulating liquids through the interstices between conductor strands. The research found that the method significantly improved breakdown voltages. More importantly, the study provided breakdown strength for cables that had been underground at a utility for 23 and 28 years. The 28-year-old cable, which was manufactured by Anaconda in 1969, had a 15 kV rating, a 34 mm2 (2 AWG) copper conductor, an insulation thickness of 5.6 mm (220 mils), a copper tape neutral, and a PVC jacket. In addition to the 28 years of service, four months of laboratory age testing in tap water with 2.5Vo was applied. The 23-year-old cable, manufactured by Okonite, had a 25 kV rating, a 34 mm2 (2 AWG) copper conductor, an insulation thickness of 7.1 mm (280 mils), a copper tape neutral, and a PVC jacket. This cable operated at 15 kV during its installed life. The cable was subjected to an additional six-month period of laboratory age testing in tap water with 2.5Vo applied. After field and laboratory age testing, the 28-year-old cable had an AC breakdown strength of 8.9 kV/mm (228 V/mil). After field and laboratory age testing, the 23-year-old cable had an AC breakdown strength of 5.2 kV/mm (132 V/mil) and an impulse voltage breakdown stress of 28 kV/mm (712 V/mil). It should be noted that these cables had been immersed in tap water for 40 days to restore the wet field conditions before the tests were performed.

Table 7-2 summarizes the results for these cables. The breakdown strengths are low by comparison to the new EPR insulation results above but range from 4.3 to 5.5 times operating voltage. These cables would have passed a 3Vo high-potential test, both when removed from service and following the additional laboratory stress age testing at 2.5Vo. Thus, they had more than sufficient capability to withstand a high-potential test.

Table 7-2
Field-Aged Black EPR Insulation Capability

Cable	AC Breakdown Strength	Nominal Operating Stress	Impulse Breakdown Voltage
28-year-old, 15 kV Anaconda	8.9 kV/mm	1.6 kV	N/A
23 year old, 25 kV Okonite	5.2 kV/mm	1.2 kV	28 kV/mm

8 RECOMMENDATIONS

8.1 PROVIDE DRY ENVIRONMENT

Review drawings and walk down cable runs to ensure design compliance and to identify potential areas for further investigation. If underground medium voltage cables can be kept dry, it is conservative to do so. Institute low point manhole inspection and pumping or install and maintain automatic sump pumps. By design, the manholes should be at the low points with the conduits in the connecting duct banks sloped for water to drain into the manholes.

If a review of the design drawings shows sloped conduit/duct bank with manholes as the low point for the connecting conduits, the utility can have reasonable assurance they are keeping these cables dry. Greater assurance is obtained by walking down the duct bank to verify no evidence of settling/duct bank shift has occurred. Nonetheless, for license renewal, the NRC has never completely accepted this argument of “rain and drain” in lieu of an aging management program. The basis for the NRC challenging this argument is the assumption that the duct bank was truly installed without deviations from the design drawings. Another issue that should be considered by the utility is the ability of a sump pump to keep up with the flow of water into the manhole.

An issue for license renewal is the interpretation of the current definition of significant moisture in NUREG 1801, Generic Aging Lessons Learned (GALL) Report [Reference 33]. Currently, the NRC defines significant moisture as submergence lasting more than a few days. This definition really needs to be refined, since most of the data suggests that the issues associated with water-enhanced aging cable takes several months to years to develop.

8.2 PREPARE FOR CABLE FAILURES

Determine importance of circuits and create an order of pro-active actions that match an established priority list of these circuits. Cables used for Safety-Related applications, Station Black Out, Offsite Power, Fire Protection, and other cables important to plant operation should be considered in the scope of interest.

If no failures have occurred to-date:

- Have processes in place that ensure that any failure that occurs must be thoroughly and carefully investigated.
  - Testing, removal, and assessment of failed cable must be procedurally controlled, documented, and reported.
  - Assessment of failure must be done by a knowledgeable laboratory to allow an accurate determination of root cause.
  - Corrective action to like circuits must be based on results, but the actions should be conservative.

- Initiate cable replacement or a program of cable replacement, if a generic degradation that can affect like applications is detected.

At a minimum, a proven, modern cable design should be used for replacements. Based upon successful performance, pink or brown EPR is the current material of industry preference. In addition, there are new types of moisture impervious cable that provide a viable replacement option to lead-sheathed or submarine cables. These moisture impervious cables can be installed in existing duct bank applications, since the cable diameter is similar to EPR insulated cables. Cables remaining from original plant construction and old inventory cables are not recommended for use as replacements.

8.3 Share Failure Resolutions

- Preserve failure data
- Identify root cause
- Contribute findings to the Operating Experience system
- Maintain connections to cable replacement expertise, materials, and tools
- Share lessons-learned with the industry

9 PATH FORWARD

9.1 INDUSTRY UNITY

Maintain industry consensus using the Medium Voltage Underground (MVU) Cable Task Force, the MVU Cable survey, this MVU Cable White Paper, and a MVU Cable Task Force activities plan. Encourage cable experts to participate in the MVU Cable Task Force and the EPRI Cable Users Group.

9.2 PRELIMINARY ACTIONS

Encourage all utilities to:

- Complete the MVU Cable survey
- Participate in the final review of this White Paper
- Concur with the summary of this White Paper
- Agree on the resolution recommendations

9.3 MVU CABLE TASK FORCE PLAN

The NEI MVU Cable Task Force as follows:

- Compile Survey result
- Issue the final White Paper
- Request that INPO establish additional data capture capability to enable EPIX to document and track any new MVU Cable failures.
- Transmit the White Paper to the NRC
- After the NRC has reviewed the White Paper, meet with them to ensure they are satisfied with the current MVU Cable program direction
- Complete the efforts of the MVU Cable Task Force, when the items above are complete

9.4 MVU CABLE RESPONSIBILITY TRANSFER

Coordination with the License Renewal Electrical Working Group during the MVU Cable Task Force response development process exists because a few members of the License Renewal Electrical Working Group are also serving on the MVU Cable Task Force. Thus, ongoing communications, recommendation development, and transfer of information are easily accomplished between the Working Group and the Task Force. These groups are both under the direction of NEI.

Licensees have or will commit to some type of license renewal aging management program for medium voltage underground cable as part of the license renewal application. This new license renewal commitment as well as current licensing basis (CLB) commitments for medium voltage underground cable will be applicable to the period of extended operation. Thus, the License Renewal Electrical Working Group is the appropriate group to accept the ongoing resolution of medium voltage underground cable issues.

The Statement of Consideration (SOC) for the 1995 license renewal rule (10 CFR Part 54) emphasizes the NRC's position that the existing regulatory process (i.e., 10 CFR Part 50) is adequate to ensure that the licensing basis of all currently operating plants provides and maintains an adequate level of safety associated with medium voltage underground cable issues. NUREG-1801, Section XI.E3 provides guidance for an aging management program that the NRC staff finds acceptable. As industry experience develops for medium voltage underground cable, CLB, and license renewal commitments can be modified as needed to maintain NRC expectations for replacing, monitoring, or testing medium voltage underground cable.

APPENDIX A

NEI Medium Voltage Underground (MVU) Cable Industry Survey

NEI is conducting an industry-wide survey to collect information related to a new issue identified by the NRC concerning Medium voltage Underground (MVU) cable aging concerns. This data is requested to help determine the extent to which plant safety may be challenged in the future due to increased failure frequency. This survey is also aimed at locating our industry cable experts for additional communications and invitations to industry consensus-setting workshops and/or training sessions. Your participation in this survey is very much appreciated.

This survey provides the NEI Task Force with information about:

Extent of medium voltage cable that is underground for safety-related and critical functions along with attribute data concerning:

- Circuit numbers (or number of circuits)
- Rated and applied voltage levels
- Cable manufacturer, insulation type and color
- Cable age (based on year installed)
- Cable functions
- Cable conductor shield attributes and insulation shield attributes and
- If failures occurred, information about the failure root cause and cable replacement description

Definitions:

Medium Voltage – defined as being between 2,000 volts and 35,000 volts and **excludes security applications**.

Underground – defined as any cable that could potentially be in a wet environment, including any installations below grade in the plant, as well as those that may be wet for any reason above grade.

EPR – stands for ethylene propylene rubber

XLPE – stands for cross-linked polyethylene

MVU Cable stands for medium voltage underground cable

SURVEY QUESTIONS START HERE

1A. Please identify the company or site's medium voltage cable expert and provide contact information. It is recommended that this person complete the survey. **Data is requested for all site units as well as any common circuits.**
Name ______________________________
Company ___________________________
Site Unit (s) ________________________
Telephone __________________________
Email ______________________________
Fax _______________________________

1B. Do you have any medium voltage cables located <u>underground</u>? (Yes/No)________

If the answer is "**No,**" SCROLL to bottom and CLICK the "Submit" button, and the survey is **complete.** If answer is "**Yes**", **please continue the survey**.

2. For medium voltage underground cable routing methods, check all installation types that apply:
____ Conduit
____ Duct banks
____ Direct-Buried
____ Enclosed trench on supports or trays

3A. How many total medium voltage circuits are installed? _____________

3B. Of these circuits, how many are "underground" as defined above? _____________

3C. Please calculate the percent MVU Cable by dividing item 3B by item 3A or __________% MVU Cable design

4A. With respect to MVU Cable circuits in question 3B above, are any MVU Cable circuits <u>known</u> to be wetted? (Yes/No)
4B. If question 4A is YES, how many are wetted? _________________
4C. Please calculate the percentage of MVU Cable circuits known to be wetted by dividing item 4B by item 3A = ___________% MVU Cable design and wetted.

5. Is there a water reduction/minimization (e.g., manhole pumping) program? (Yes/No)

6. List data for Original Installation MVU Cable Circuits Data on Sheet 1. If you are unable to define each unit, you may enter number of circuits and provide a brief explanation in the right end column. The shaded area at the top of each sheet contains an example response for each column.

Circuit number (optional)	Cable Rated Voltage.	Applied System Voltage	Manufacturer	Insulation Type	Year Installed	Function Codes- enter all that apply	Shielded	Conductor Shield Type	Insulation Shield Type	Comments	
Examples and data options appear in the shaded area			EPR Producers:	XLPE	1973	G= general non-safety service	Yes/No	Cotton tape type	Cotton tape/helical copper tape type	(To clarify any data supplied)	
	2kV	2.20 kV-varies	Okonite								
	5 kV	4.16 kV	Kerite Anaconda	EPR-black		SR= safety related		Extruded polymer type	Extruded polymer/helical copper tape type		
	8 kV	6.9 kV	Cablec BICC	EPR (Pink or red)		R= Appendix R		(Important information for operations)	Extruded polymer copper strands type		
	15 kV	13.8 kV	General Cable XLPE producers:	EPR (gray)		SBO= station blackout			Combined polymer shield/jacket with imbedded copper strands type		
	35 kV	33kV	GE Others	Butyl Rubber		OP=offsite power			(Important information for testing)		
				Natural rubber		ER = supplies a critical load as defined by INPO AP-913					
				XLPE-TR							
Data Starts Below											

7. List MVU Cable Failure Data in Sheet 2. This failure data is very important. Please be as thorough as possible, including identification of failure root cause.

Circuit number (optional)	Rated System Voltage	Applied Voltage	Manufacturer	Insulation Type	Year Installed	Year Failed	Corrective Action Reference and Date	Operating Experience Reference and data	Were there actions taken due to generic implications	Other Comments	
Examples and data options appear in the shaded area	2 kV		EPR Producers: Okonite Kerite	XLPE	1973	1993	Yes/No	INPO OE number	Replacement of similar cables	(To clarify any data supplied)	
	5 kV	4.16 Kv	Anaconda Cablec	EPR-black							
	8 kV	6.9 kV	BICC General Cable	EPR (Pink or red)							
	15 kV	13.8 kV	XLPE producers:	EPR (gray)							
	35 kV	33kV	GE Others	Butyl Rubber							
				Natural rubber							
				XLPE-TR							
Data Starts Below											

8. List Replacement MVU Cable data in Sheet 3. Is failed cable being replaced in kind or with an improved material?

Circuit number (optional)	Rated System Voltage	Applied Voltage	Manufacturer	Insulation Type	Year Installed	Year Failed	Corrective Action Reference and Date	Operating Experience Reference and data	Were there actions taken due to generic implications	Other Comments	
Examples and data options appear in the shaded area			EPR Producers:	XLPE	1973	1993	Yes/No	INPO OE number	Replacement of similar cables	(To clarify any data supplied)	
	2 kV		Okonite Kerite								
	5 kV	4.16 Kv	Anaconda Cablec	EPR-black							
	8 kV	6.9 kV	BICC General Cable	EPR (Pink or red)							
	15 kV	13.8 kV	XLPE producers:	EPR (gray)							
	35 kV	33kV	GE Others	Butyl Rubber							
				Natural rubber							
				XLPE-TR							
Data Starts Below											

9A. Does your plant currently perform electrical testing of medium voltage cables? (Yes/No)

9B. If 9A answer was YES, check all types of testing performed:

___ Leakage current
___ Insulation resistance
___ Polarization index
___ Dissipation factor (Tan δ) (Loss angle)
___ Partial discharge (off-line)
___ Partial discharge (on-line)
___ DC withstand
___ AC withstand
___ VLF AC withstand
___ Other ____________ (Specify)

9C. For each test in 9B, describe the overall method and periodicity application or list procedure title(s) and number(s).

____
____
____
____

10A. If the answer to 9A was NO, do you plan to perform such testing in the future? (Yes/No)

10B. If the answer to 10A was YES, check all the tests that are planned in future:

___ Leakage current
___ Insulation resistance
___ Polarization index
___ Dissipation factor (Tan δ) (Loss angle)
___ Partial discharge (off-line)
___ Partial discharge (on-line)
___ DC withstand
___ AC withstand
___ VLF AC withstand
___ Other ____ (Specify)

End of Survey

APPENDIX B

Acronyms and Definitions

AC	Alternating current
AWG	American Wire Gauge
BIL	Base Impulse Insulation Level
CPE	Chlorinated polyethylene rubber
CSPE	Chlorosulfonated polyethylene rubber (Hypalon)
DC	Direct current
DOE	U.S. Department of Energy
IEEE	Institute of Electronic and Electrical Engineers
EPRI	Electric Power Research Institute
EDG	Emergency diesel generator
EPR	Ethylene propylene rubber
hi-pot	High potential
HMWPE	High molecular weight polyethylene
HTK	A Kerite Company insulation polymer designation
hz	Hertz
ICEA	Insulated Cable Engineers Association
INPO	Institute for Nuclear Power Operations
kV	Kilo volts
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MCM	Thousands of circular mils (also KCM), a unit of area for conductor size
µs	Microsecond
mil	1/1000th of an inch
MVU	Medium voltage underground
NEI	Nuclear Energy Institute
NEMA	National Electrical Manufacturing Association
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
pC	Pico coulomb
PD	Partial discharge
PDEV	Partial discharge extinction voltage
PDIV	Partial discharge inception voltage
PE	Polyethylene
PVC	Polyvinyl chloride
PSE	Plant Support Engineering

Acronyms and Definitions (continued)

SSC	System, Structure, or Component
tan δ	tangent δ (a loss factor of insulation)
TDR	Time Domain Reflectometer
TR-XLPE	Tree-retardant XLPE
Vo	Phase-to-ground voltage
XLPE	Cross-linked polyethylene

APPENDIX C

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APPENDIX D

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