Condition Assessment Techniques for Laminar Dielectric Transmission Cable Systems

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ABSTRACT

As aging and higher circuit loadings lead to increased failures of pipe-type cable systems, utilities need effective techniques for assessing the key components of these systems. Many off-line and on-line diagnostic and assessment techniques are in use to inspect the condition of laminar dielectric cable systems. However, because of the high labor costs and required circuit outage of off-line testing, much of the current research and development focuses on methods of on-line monitoring.

A number of mechanisms can contribute to the failure of laminar dielectric transmission systems, including thermal deterioration, thermomechanical behavior, poor fluid quality, loss of dielectric fluid pressure, electrical activity, and corrosion of steel pipes. This report reviews such failure mechanisms in the principal components of cable systems: the cables, splices, terminations, and fluid-pressurizing systems. It then examines the current capabilities of condition assessment techniques for high-pressure fluid-filled, high-pressure gas-filled, and self-contained fluid-filled cable systems.

Among the advanced on-line monitoring and inspection techniques now under investigation is measurement of the cable insulation dissipation factor, which the report explores in detail. This proposed on-line system can include voltage, current, and phase angle transducers, as well as a signal conditioning and data acquisition unit at each end of a cable circuit. Further development of the technique will focus on the critical elements of measurement synchronization and data communications. Investigation of this and other condition assessment techniques will continue in the next few years. Plans also call for developing a series of guides to assist utility personnel in applying techniques for assessing the condition of laminar dielectric cable systems.

Keywords
Cable condition assessment
Dielectric cable systems
On-line monitoring and inspection
Pipe-type cable systems

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1 INTRODUCTION

Over 80% of the underground transmission systems in North America use laminar dielectrics. A marked reduction has occurred in the number of global suppliers of laminar dielectric cables in recent years. However, rerouting, additions to existing circuits, and new installations are still required. Pipe-type transmission cable systems—high-pressure fluid-filled (HPFF) and high-pressure gas-filled (HPGF), as well as self-contained fluid-filled (SCFF) cable systems—have provided long and satisfactory service.

About half of laminar dielectric transmission cables are approaching or have exceeded their assumed design life of 40 years. Due to aging and higher circuit loadings, the number of failures has recently increased. Utilities are concerned about the life, reliability, and repair cost of the principal components of laminar dielectric cable systems—namely, cables, splices, terminations, and fluid-pressurizing systems. Additional research will improve understanding of condition assessment techniques for reducing and avoiding such concerns and facilitate the development of more effective diagnostic means.

This report addresses condition assessment techniques for HPFF, HPGF, and SCFF ac transmission cable systems. It investigates failure mechanisms and failure modes of principal components (cables, splices, terminations, and fluid-pressurizing systems; Section 2) and evaluates the capabilities of existing diagnostic and assessment techniques (Section 3). For the identified areas, the report then focuses on advanced on-line monitoring and inspection techniques (Section 4). Plans call for the development of a series of guides under this project in the next few years. This report starts their development with a guide for measuring field laminar dielectric dissipation factors (Appendix A). In 2011, a guide for dissolved gas analysis (DGA) and paper insulation testing will be developed.

2
FAILURE MECHANISMS AND FAILURE MODES OF LAMINAR DIELECTRIC CABLE SYSTEMS

2.1 Introduction

Aging and failure mechanisms of laminar dielectric transmission systems can be categorized as follows:

- Thermal mechanisms (paper)
- Electrical mechanisms (paper, fluid)
- Chemical mechanisms (paper, fluid, pipe)
- Fluid contamination and loss of impregnant (fluid)

The failures can be caused by the following sources.

- External damage
- Poor quality of installation and workmanship
- Component and manufacturing defects
- Poor design, operation, and maintenance practices

External damage to cable systems (steel pipe for HPFF and HPGF, metallic sheath for SCFF) are the most likely cause of cable failures, according to a recent CIGRE investigation [CIGRE 2009]. To reduce dig-ins and any other construction damage to existing systems, information exchange is important, and subsurface locating procedures must be followed. For new systems, implementation of robust mechanical protection is recommended.

Elaborate quality assurance efforts must be made during installation of the cable systems. For pipe-type systems, care must be taken during important steps such as pipe preparation, cable pulling, and pipe evacuation and filling. Manufacturers' installation instructions, industry guidelines, and best practices must be followed. Failure to adhere to the required procedures can lead to serious problems. For example, some cable failures have been attributed to excessive pulling tensions and sidewall pressures. As for all field-assembled components, workmanship and sound installation practices are extremely important for reliable operation of terminations and splices. Improper assembly can lead to excessive localized high electrical stress or leakage of insulating fluid.

Some manufacturing defects may not be detected during routine factory or site acceptance tests. Manufacturing defects are considered rare but sometimes occur even after years of operation. The cables cannot usually tolerate localized stress concentrations brought about by insulation contaminants such as metal particles. The introduction of such particulates is rare but has been observed in some cases, resulting in cable failure tied to such asperities. Waxing, the result of fluid polymerization due to low-level ionization activity, can also affect the long-term performance of laminar dielectric cables.

System design, operation, and maintenance practices are vital to long-term, trouble-free operation of laminar dielectric cable systems. Cables may operate satisfactorily for many years without maintenance and show no obvious signs of deterioration. However, when problems arise, repairs can be time-consuming and expensive and can affect circuit availability.

The failure mechanisms lead to failure modes that limit the useful life of laminar dielectric cable systems. Some important failure modes are discussed in the following sections.

2.2 Failure Mechanisms and Failure Modes

2.2.1 Thermal Deterioration

Because of its critical importance, thermal aging of paper—the prime aging process—received worldwide attention following transformer investigations in the 1920s, and the process was quite well understood. Thermal cable paper aging was further refined in an EPRI study in 1998 [EPRI 1998a]. Thermal aging and some failure mechanisms are closely interrelated.

It is well-known that impregnated paper high-voltage insulation deteriorates more rapidly as the operating temperature of the insulation increases. This is why industry standards stipulate limits on both operating and emergency temperatures. Sustained high temperatures caused by hot spots or overloads can lead to thermal runaway and insulation breakdown.

Paper deterioration is a result of several factors. The paper loses mechanical strength as increasing temperatures accelerate chemical changes in the paper. More specifically, the paper loses folding endurance, tear strength, elongation to break, and tensile strength. A chemical property related to cellulose chain length, the degree of polymerization, also decreases. The dielectric dissipation factor increases.

Proximity to heat sources such as steam pipes has resulted in cable failures. Despite due precautions, hot spots along cable routes have also resulted in cable failures. Thus, excessive thermal action beyond the norms constitutes the failure mechanism.

Another form of deterioration of the impregnated paper insulation results from the generation of chemically bound moisture from within the paper. Some of this moisture is eventually released to the pipe-filling fluid, but the majority of the moisture is initially absorbed by and retained in the paper. The increased moisture levels result in a higher dissipation factor and higher dielectric losses, which increase the rate of thermal deterioration and can eventually lead to thermal-electric instability [IEEE 2002].

The amount of thermal decomposition of the impregnated paper insulation also depends on the loading history of the cable system and the temperature profile along the length of the cable system. One of the underlying thermal design principles for impregnated paper transmission cables is that mechanical properties of the cable insulation will deteriorate by about 10% if they operate continuously at 85°C for 40 years [EPRI 1998a]. Conversely, the insulation in an HPFF cable system may be expected to have a life longer than 40 years if it is operated at temperatures of less than 85°C. Industry experience indicates that cable life decreases by a factor of approximately 2 if the continuous operating temperature is increased by 8 to 10°C. This loss of insulation life is a result of deterioration of the mechanical and chemical properties of the cellulose.

2.2.2 Thermomechanical Behavior

Thermomechanical behavior (TMB)—movement and bending—mostly affects cables with thicker insulation. TMB is caused by cable gravitational force, vibration, or expansion and contraction of the cable in response to temperature variations caused by circuit load cycling. Mechanical damage has occurred in some instances when the cables slide down pipes or ducts due to elevation changes and gravity. Operating experience shows that mechanical forces can bend the cables adjacent to the splice stress cones within joint casings. Sliding of cables in pipes and ducts is usually a result of the combined ratcheting effect of gravitational forces and load cycling. In some locations where cables are exposed to traffic, traffic-caused vibration can also cause cables to move.

Although TMB problems could occur at any point in a pipe-type cable system, experience to date indicates that they occur primarily in joint casings. Most TMB problems in joint casings have occurred with 345-kV cable systems due to the greater thickness of insulating paper.

Rare cable failures in pipes have also been reported at the 230-kV level [EPRI 2008a]. Such a situation is not ruled out for 138-kV HPFF systems. However, laminated paper polypropylene insulated cables that have been installed since the late 1980s at 230- to 345-kV levels have not experienced any thermomechanical bending failures, very likely due to reduced insulation wall thicknesses.

TMB may result in localized electric field distortions and stress enhancements. The cause is softness in the insulation that leads to tape movement and increased paper-tape butt-gap depth, due to repeated bending. The result is localized electric field stress enhancement around the butt gaps. The weakest link in a laminar dielectric cable is the butt-gap depth. This is why thinner papers are used in high-stress regions near the conductor. The observed softness is a consequence of the radial and axial alignment of several butt gaps involving several tape layers, due to tape movement.

A similar problem is the failure of cable terminations due to the mechanical deformation of their electrical stress-relief components. This problem has resulted from movement of the cable inside the termination due to gravity or shifting of the stress cone relative to the cable in response to differential hydraulic pressure. The shifting due to hydraulic pressure can be caused during fluid filling or result from fault-initiated pressure transients.

2.2.3 Dielectric Fluid Quality and Condition

The dielectric fluid for HPFF and SCFF cables maintains its electrical, chemical, and physical properties up to 160ºC in the absence of oxygen. Operating experience verifies that there is little deterioration of the pipe-filling fluid and SCFF cable fluid under normal operating conditions. However, since the fluid is handled in the field, it can be contaminated by external sources, such as excessive moisture, detergents, and particulates—even with good field handling practices for fluid. This can result in a high fluid dissipation factor that may call for treatment—degassing and

Fuller's earth processing. The inside condition of pipes and internal pipe coatings can also contaminate pipe fluid. In addition to particulates that can be mechanically filtered, higher concentrations of soluble acids and other polar compounds have been observed in some pipe fluids.

HPFF cable failures caused by poor dielectric quality in a pipe fluid are rare, probably because the cable's carbon-loaded paper insulation shield largely protects the internal insulation paper from many external contaminants in the pipe fluid, with the exception of soluble compounds.

Influence of the impregnant and the extent of the mixing of the pipe fluid may affect the chemical stability of the insulation system. Two types of impregnating fluids have been used: mineral oils in earlier cables and polybutene and alkylbenzene fluid in ones since the 1970s. As a result of the inevitable load cycling, some interchange of the two fluids takes place in the outer layers of the paper insulation. Excessive displacement of the impregnant by the much lower viscosity pipe fluid can shorten cable life due to the superior quality of the retained, original high-viscosity impregnant: chemical stability, oxidative resistance, dissipation factor and reduced ability to pick up impurities, solubility for several dissolved gases, and breakdown strength. Compared to the most commonly used naphthenic impregnant, its early paraffinic counterpart is less desirable from the standpoint of cable insulation life [EPRI 2009a].

While the vast majority of HPFF cables do not yield high hydrogen levels (greater than 15,000 ppm), extraordinarily high concentrations of hydrogen have been observed in several domestic and foreign HPFF cables. While such high hydrogen concentrations appear to be confined to the pipe fluid, they can eventually lead to cable failure by impacting the outer shielding.

During storage, transportation, handling, and installation, and under the influence of gravity in vertical or sloped installation, the viscous impregnant may be lost from the outer paper layers in HPGF cables. There is no dielectric liquid to make up for it, as with HPFF cables. This is one of the reasons that the insulation wall thickness of an HPGF cable is greater than that of its HPFF counterpart. In addition, the dielectric strength of nitrogen gas is lower than that of a dielectric liquid.

2.2.4 Dielectric Fluid Pressure

If the cables are operated at pressures below 100 psig, ionization may be detected, especially in the terminations. This ionization could lead to long-term degradation even after the restoration of full pressure. In a few cases, HPFF cable terminations have failed within minutes or hours of a complete pressure loss. Loss of pipe pressure can be caused by operational situations or elevation changes, especially for terminations. Failures of fluid-pressurizing systems, pumping plants (reservoir tank, gauge, and control), component leaks, and pipe-fluid leaks can all cause the loss of pipe-fluid pressures. Procedures for initial pressurization, depressurization for maintenance or repair, and repressurization after loss of pressure must be closely followed [EPRI 2008b].

2.2.5 Electrical Activities

Electrical activities (partial discharge, tracking, ionization) can be caused by component defects or low fluid pressures and can result in cable failures. Any uniform deterioration of the impregnated paper insulation due to rated voltage power frequency stress is insignificant compared to thermal and mechanical aging. Localized problems, such as at terminations, have resulted in system failures or system outages, but these problems have not generally been a limiting factor in the life of the entire cable system [EPRI 1998a].

2.2.6 Corrosion of Steel Pipes

A fundamental requirement for the operation of an HPFF cable system is to maintain the pipe pressure at a nominal value of 200 psig. To accomplish this, the integrity of the steel pipe must be maintained. In several HPFF cable systems, their economic life has been limited by corrosion of the steel pipe. These situations are most severe when stray currents related to dc transportation systems are present. However, there have also been problems with aboveground installations where salt corrosion combined with deterioration of the pipe corrosion coating led to leaks and, in some cases, loss of pressure. A recent EPRI-sponsored project conducted a thorough investigation of buried steel pipe corrosion in pipe-type cable systems [EPRI 2010].

3 DIAGNOSTIC AND ASSESSMENT TECHNIQUES WITH ON-LINE MONITORING

3.1 Introduction

Diagnostic and assessment techniques for laminar dielectric cable systems include both invasive and noninvasive methods. Noninvasive techniques can be applied either on-line or off-line. They include, but are not limited to, dissolved gas analysis, furfural content, key fluid quality tests (for example, moisture content and dissipation factor), partial discharge, circuit dissipation factor measurements, and radiographic inspection.

Because of high labor costs and circuit outage requirements in off-line testing, combined with increasingly advanced automatic data collection capabilities, on-line monitoring is attractive for condition and life assessment of laminar dielectric cables [EPRI 2009b].

Table 3-1 lists inspection and monitoring techniques for laminar dielectric underground transmission lines. The techniques are grouped into four sections.

- Presently available on-line continuous monitoring methods
- Presently available off-line maintenance inspection, with opportunities for continuous monitoring methods
- Presently available off-line maintenance inspection based on laboratory tests, with opportunities for on-line continuous monitoring methods
- Other desirable on-line continuous inspection and monitoring methods

Figures 3-1 and 3-2 are schematic diagrams of the inspection and monitoring applications for HPFF, HPGF, and SCFF transmission lines, respectively. The following sections discuss the techniques in detail.

Table 3-1
Inspection and Monitoring of Laminar Dielectric Underground Transmission Lines

Failure Modes/Indicators	Diagnostic Method	Applicable Cable Systems and Auxiliary Equipment	Overall Status	Monitoring Capability	Sensor Opportunity	Comments for Future Research and Prioritization
Presently Available On-Line Continuous Monitoring						
Hot spots along cables—limiting factor of loading capability and insulation aging	Temperature	HPFF, HPGF, SCFF	On-line monitoring available	Monitoring through distributed fiber-optical sensors or thermocouples	Distributed fiber-optic temperature sensing and thermocouples available	Commercial systems available
Hydraulic system malfunction	Fluid or gas pressure, flow, pumping plant operation, reservoir fluid levels, piping damage and leaks	HPFF, HPGF, SCFF	On-line monitoring available	Monitoring at pressurizing systems	Pressure and other transducers available	Commercial systems available
Deterioration of cable insulation and shield systems; localized defects, especially at joints, terminations, and interfaces	Partial discharge (PD) detection, shield current measurement	HPFF, HPGF, SCFF	On-line monitoring available; expensive and time-consuming inspection	Monitoring through capacitive and/or inductive coupling or acoustic emission sensors; off-line and on-line maintenance inspection	Various sensors available	Commercial systems available; R&D on sensors, sensitivity, effectiveness, integration, noise filtering, data processing
Buried steel pipe corrosion and coating damage	Cathodic protection system settings and connections, half	HPFF, HPGF	On-line monitoring available	Monitoring of cathodic protection systems at	Potential and current transducers, as well as remote reference cells, available	Commercial systems available

	cell potential, and aboveground survey			substations, vaults or test stations		
Metallic sheath/shield corrosion	Cathodic protection system settings and connections	SCFF	On-line monitoring available	Monitoring of cathodic protection systems at substations	Potential and current transducers available	Commercial systems available
Fluid or gas leak	Fluid pressure, temperature, circuit loading, ambient condition, flow, and others	HPFF, HPGF, SCFF	On-line monitoring available	Monitoring at pressurizing systems and/or along cable route	Various transducers available	USi/EPRI system available; ConEd/EPRI and Kinectrics/EPRI systems under investigation.

Table 3-1 (Continued)

Failure Modes/Indicators	Diagnostic Method	Applicable Cable Systems and Auxiliary Equipment	Overall Status	Monitoring Capability	Sensor Opportunity	Comments for Future Research and Prioritization
Presently Available Off-Line Maintenance Inspection, With Opportunities for On-Line Continuous Monitoring						
Overall insulation integrity, such as moisture, fluid contamination	Circuit dissipation factor	HPFF, HPGF, SCFF	In-field test with special equipment	Off-line maintenance inspection	Development opportunities for on-line monitoring	EPRI in-field system available for laminar dielectric cables [EPRI 1993]
Bonding and link box corrosion, loose connection, insulation damage	Sheath current measurements	SCFF	In-person inspection	Off-line maintenance inspection	Sensors available but need integration	On-line monitoring desirable
Sheath voltage limiter (SVL) failure	SVL current measurements	SCFF	In-person inspection	Off-line maintenance inspection	Sensors available but need integration	On-line monitoring desirable
Vault hardware and components (ceiling, walls, pipe, clamps, ground wires, racks, pumping) degradation, corrosion, overheating, flooding, safety-related gas level	Optical image, infrared image, vibration, acoustic sensing, and temperature-indicating strips on components for cracks, leaks, corrosion, coating damage, component damage, safety-related gas level, and other	HPFF, HPGF, SCFF	Time-consuming inspection with safety concerns	Off-line or on-line maintenance inspection	Sensor development opportunities; some sensors available but need integration	On-line monitoring desirable
Internal movement,	X-ray inspection	HPFF, HPGF, SCFF	Expensive and time-	Off-line maintenance	Portable X-ray equipment	On-line monitoring unlikely

misalignment or damage of cables and accessories			consuming inspection	inspection	available	
Fluid leak location	Perfluorocarbon tracers	HPFF, SCFF	Time-consuming inspection	Off-line location of detected leaks	Sensors available	On-line monitoring unlikely
Fault location	Fault current	HPFF, HPGF, SCFF	On-line monitoring available	Monitoring of fault current at each end of a cable section	Fiber-optic current sensors developed	Systems under development by Tokyo Electric Power Company for extruded dielectric cables

Table 3-1 (Continued)

Failure Modes/Indicators	Diagnostic Method	Applicable Cable Systems and Auxiliary Equipment	Overall Status	Monitoring Capability	Sensor Opportunity	Comments for Future Research and Prioritization
Presently Available Off-Line Maintenance Inspection Based on Laboratory Tests, With Opportunities for On-Line Continuous Monitoring						
Aging/degradation of fluid or paper insulation—indicator of hot spots, partial discharge, or arcing	Dissolved gas analysis, fluid dissipation factor, dc resistance, ac resistance, moisture content, particle content, gas absorption capability	HPFF, HPGF, SCFF	Laboratory test with fluid samples from operating equipment	Off-line maintenance inspection, fluid samples from operating equipment	Sensor development opportunities	On-line monitoring under investigation by EPRI
Aging of paper insulation	Degree of polymerization (DP), mechanical strength, paper dissipation factor, furfural	HPFF, HPGF, SCFF	Laboratory test with samples from operating equipment	Mechanical/electric strength versus DP known	Sensor development opportunities	On-line monitoring unlikely

Other Desirable On-Line Continuous Inspection and Monitoring						
Thermomechanical bending	Strain sensing, sidewall pressure sensing	HPFF, HPGF, SCFF	New	On-line monitoring desirable	Sensor development opportunities	On-line monitoring desirable
Lead sheath fatigue	Strain sensing	SCFF	New	On-line monitoring desirable	Sensor development opportunities	On-line monitoring desirable

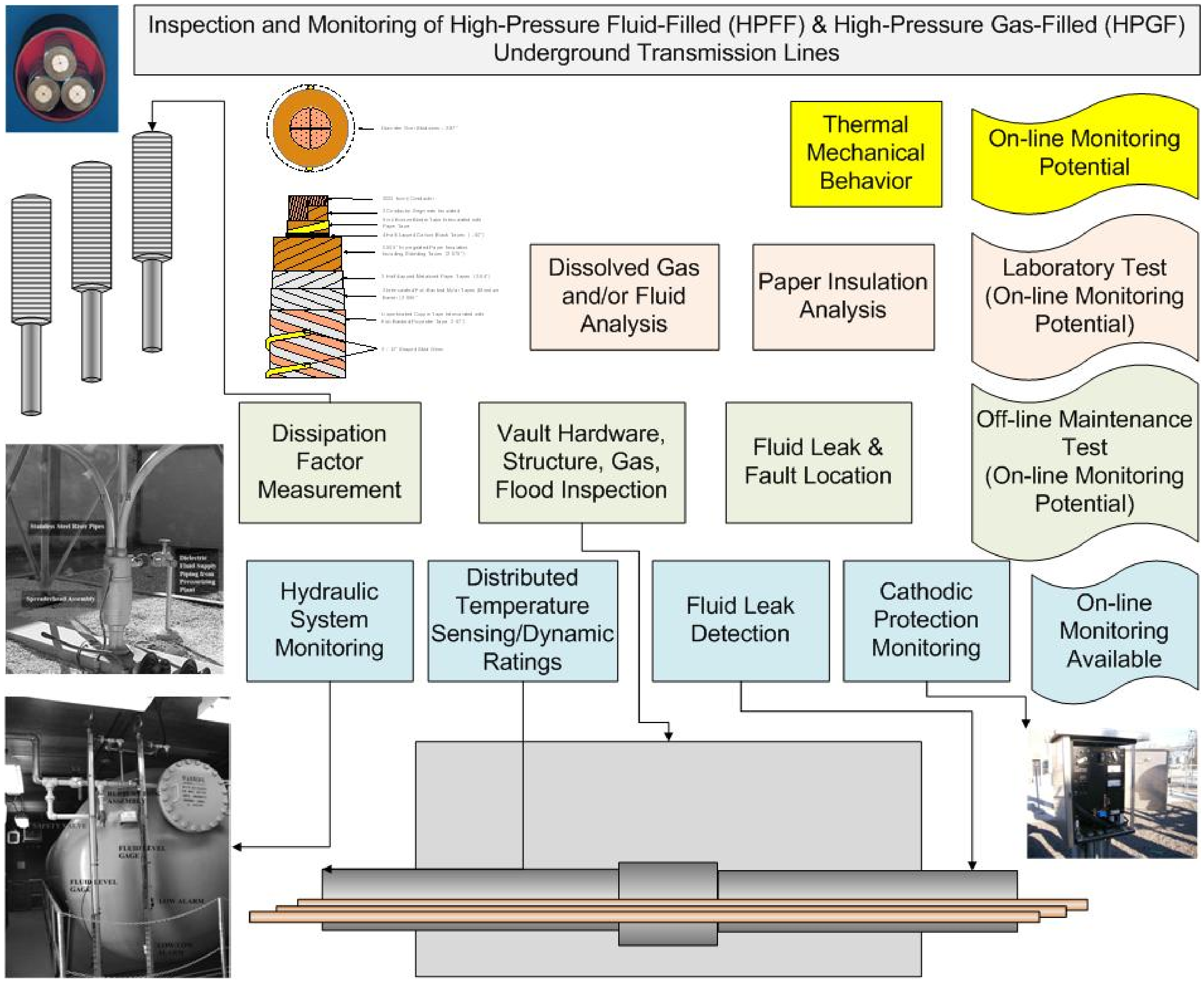

Figure 3-1
Inspection and Monitoring of HPFF and HPGF Underground Transmission Lines

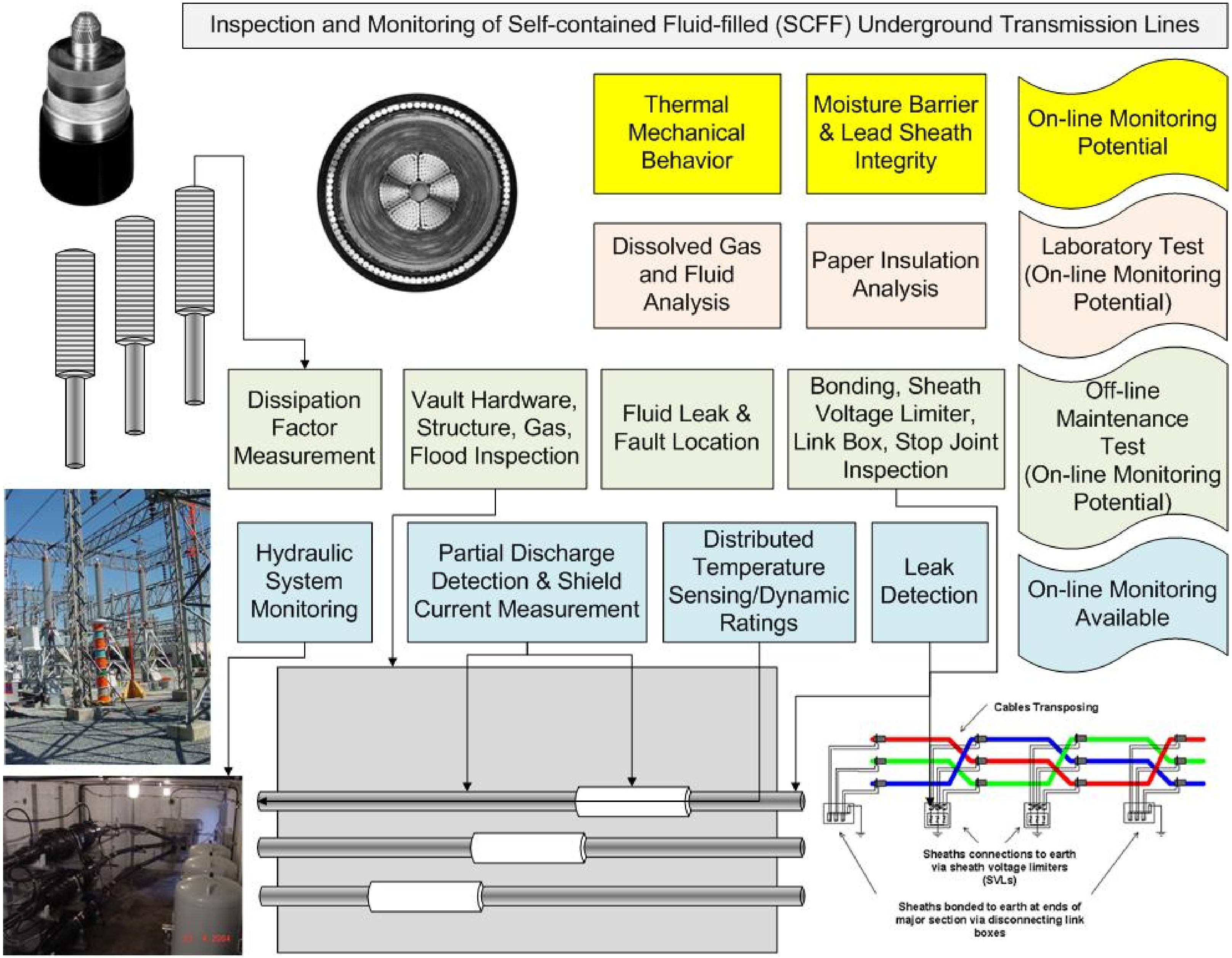

Figure 3-2
Inspection and Monitoring of Self-Contained Fluid-Filled Underground Transmission Lines

3.2 Temperature Monitoring and Surveys

Temperature monitoring and surveys are noninvasive techniques. Temperatures are measured using fiber-optic sensing or thermocouples. Fiber-optic sensing has been in use for several decades to detect various physical and chemical parameters. The characteristics of the fibers and the way light interacts with the fiber and fiber coating, or the environment around the fiber, are the basis for various sensor technologies. Fiber-optic sensors have many advantages over conventional sensors:

- They are immune to electromagnetic interference.
- They can be configured as distributed sensors as well as point sensors.
- They can operate at high electrical potential.
- They are resistant to humidity and corrosion.
- They can be made small in size and light in weight.

In remote-sensing applications, a segment of the fiber is used as a sensor gauge while a long length of the same or another fiber is used to convey the sensed information to a remote station. No electrical power supply is needed at the sensor locations. A distributed sensor can be constructed by multiplexing point sensors along the length. Signal-processing devices (for example, splitters, combiners, multiplexers, filters, and delay lines) can also be made of fiber elements.

Both point sensors and distributed sensors are used for measuring temperatures. Point sensors use a phosphorescent material at the end of the fiber. The temperature of transmission cable splices, for example, can be monitored using point sensors.

Distributed temperature sensors (DTSs) realize the technology of laser injection into the optical fiber. A fraction of the laser pulses is absorbed in the fiber and backscattered as Raman light signals. The local temperature determines the intensity of the Raman signals. The intensity is used to calculate the temperature at that location. The time of flight of the laser light, optoelectronics, and a computer are used to determine location of the specific backscattered Raman light. Multimode or single-mode fibers are used for distributed temperature sensors. In multimode systems (1ºC accuracy), about 1 meter of fiber length is needed to create a significant backscatter signal, while 4 to10 meters is needed for the single-mode fiber (2.5ºC accuracy). These requirements designate the spatial resolution of the multimode and single-mode fibers. Multimode optical fibers are suitable for most DTS applications, with a maximum range of 8 to 10 km. They are typically used for short-range communication systems—for example, within office buildings. Single-mode optical fibers are used only for very long range DTS applications, with a maximum range of 30 to 40 km. They are commonly used for long-distance communication systems.

The sensors can be installed in a spare duct or a separate duct designed for this purpose. The installation can be used for hot spot management, overload detection, and real-time dynamic thermal circuit ratings. Figure 3-3 shows DTS optical fibers in a 3-inch PVC conduit adjacent to a pipe-type cable pipe [EPRI 2002].

EPRI began using this technology in underground cable systems in the mid-1990s with a York DTS-80 system (in 2003, the equipment was updated to a Sensa DTS-800) to measure distributed temperatures along underground cable routes. In addition to their use for dynamic thermal rating and hot spot identification, applications of optical fiber temperature sensing could be expanded to fault location, fire detection, and other uses.

Figure 3-3
Distributed Temperature-Sensing Optical Fibers in a 3-Inch PVC Conduit Adjacent to a Pipe-Type Cable Pipe

3.3 Insulation Dissipation Factor Measurement

Insulation dissipation factor or tan δ measurement is a primary quality control measurement for fluid-impregnated paper insulation. It influences the dielectric losses in the cable system and is a routine factory acceptance test for all production cables. It has also been used for long-term qualification testing to determine the amount of deterioration of fluid-impregnated cable insulation. If there are consistent increases in the cable insulation dissipation factor, then either the insulation has been contaminated or aging of the cable insulation has occurred.

Several phenomena can result in an increased dissipation factor for fluid-impregnated paper insulation.

- Decomposition products of cellulose, such as water, and fluid molecules produced by high temperatures
- Moisture ingress through the cable moisture barrier
- Electrical ionization of gases
- Ionic contaminants of the insulating fluids

Section 4 presents detailed discussions of insulation dissipation factor measurements.

3.4 Dissolved Gas Analysis and Fluid Quality Tests

Comprehensive electrical, chemical, and physical property tests can be performed on samples of dielectric fluid taken from cable circuits. Two types of tests are used to determine the condition of the cables:

- Dissolved gas analysis
- Fluid quality tests

Dissolved gas analysis is routinely applied to both transformer and cable diagnostics. It is well-known that DGA measurements are an effective means of identifying localized defects in HPFF and SCFF cable systems. DGA can be applied through periodic sampling and measurement or continuous monitoring to develop trending indications. Fluid samples can be collected from cable circuits using syringes or the EPRI-developed EPRI Disposable Oil Sampling System cells [EPRI 1998b] to maximize repeatability and to facilitate comparison.

The following tests can also be performed on the dielectric fluid samples to determine the quality of the fluid:

1. *Moisture content test*—directly measures whether the dielectric fluid has been contaminated with water from external sources or from cable deterioration
2. *Electric breakdown strength test*—indicates whether water or other contaminants have degraded the electrical strength of the dielectric fluid
3. *Electrical dissipation factor test*—offers a sensitive indicator of polar contaminants in the dielectric fluid such as peroxides or water
4. *Peroxide content test*—directly measures a relatively common contaminant that will eventually degrade the dissipation factor of the dielectric fluid
5. *Neutralization number* test—indicates the acidity of the dielectric fluid, which increases with oxidation of the fluid
6. *Gas absorption test*—indicates the ability of the fluid to absorb gaseous by-products of insulation ionization, which is especially important for extra high voltage SCFF cable fluids (see ASTM D-2300)
7. *Furfural content test*—measures a cellulose decomposition by-product that is a sensitive indicator of uniform thermal aging

Results of the first six tests indicate the general quality of the dielectric fluid. Results of the furfural concentration measurements indicate thermal aging of the cable insulation.

The best use of fluid quality tests is to conduct periodic fluid sampling and measurement and monitor their trends over time. For fluid-filled transformers, periodic sampling and testing have been taken a step further: several commercially available on-line gas-monitoring systems are now available that provide almost continuous sampling, measurement, and trending. So far, this approach has not been put into practice with HPFF or SCFF cable systems because of the added complexity posed by their high-pressure operating conditions.

EPRI is developing novel on-line DGA monitoring systems for use on transformers. One technology is the metal-insulator-semiconductor (MIS) chemical sensor, which is a solid-state device that detects multigases such as hydrogen and acetylene. EPRI also funded a study in fiber-optic sensors for the on-line detection of hydrogen and acetylene inside power transformers. Novel holey fibers were recently developed to detect hydrogen, and optical laser photoacoustic spectroscopy has been proposed for acetylene detection.

The monitoring device that uses the MIS technology and fiber-optic methods for detecting dissolved gases would be attractive for fluid monitoring of HPFF or SCFF cable systems. An EPRI study examined the feasibility of using on-line DGA monitoring equipment on static, oscillating, and circulating HPFF pipe-type cable systems and addressed the added complexity posed by the high pressure under which fluid-filled cables operate [EPRI 2009c]. Several commercially available on-line gas-monitoring systems primarily used for transformers are available, such as the multigas analyzers from Serveron and Kelman and the single-gas analyzers from GE Energy (HYDRAN®) and Morgan Schaeffer [CIGRE 2010]. The study recommended performing a laboratory study to investigate effectiveness of these analyzers in monitoring HPFF cables.

In addition, on-line monitoring of the fluid dissipation factor and moisture content is also of value to assess fluid condition. Planning of these projects is in progress within EPRI.

3.5 Invasive Paper Property Tests

Invasive paper property tests include a series of electrical, mechanical, and chemical tests performed on the impregnated and/or dry paper tapes, depending on the type of test. The tests performed on the prepared paper samples include the following measurements, in accordance with the cited ASTM procedures:

- Moisture content, ASTM D-3277
- Dissipation factor @ 80°C, ASTM D-150
- Radial dissipation factor, IEEE 83
- Dielectric breakdown strength, ASTM D-149
- Dry tensile strength, ASTM D-828
- Wet tensile strength, ASTM D-829
- Degree of polymerization, ASTM 4243
- Folding endurance, ASTMD-2176
- Magenta dye

The cable piece should be carefully examined during the dissection process for general appearance, butt-gap width, and paper impregnation. The butt gaps should be uniformly distributed, and the paper tapes should be well saturated with the impregnating dielectric fluid.

The measured moisture content is expressed as the mass of water retained by a unit mass of impregnated paper in parts per million, as opposed to the typical representation in terms of mass of water per unit mass of dry fluid-free paper.

The dissipation factor of the paper piece is to be determined on selected tape(s) in each reversal at 80°C at 500 V/mil using a cell with rectangular electrodes.

The dry tensile strength of fluid-free paper tapes decreases with thermal aging. This is due to both the weakening of the paper fiber strength and the interfiber bonding. Paper is not known to age electrically in a gradual manner, as holds for thermal aging; electrical problems result in a serious and much more rapid loss of dielectric strength. If the same paper is used, the tensile strength of thermally aged tapes near the insulation shield is the highest, and it gradually decreases toward the conductor, where temperature is the highest.

Wet tensile strength, which is a measure of the tensile strength of water-soaked, fluid-free tapes, indicates the degree of interfiber bonding in paper. Unlike the traditional mechanical properties of paper (such as tensile strength and folding endurance) that gradually decrease with thermal aging, wet tensile strength initially increases to a peak and then decreases as the thermal aging progresses. This peak, a characteristic of wet tensile strength in all cellulose papers, is singularly governed by temperature and time. A cable whose tapes have experienced some aging does exhibit the wet tensile strength peak, to some extent, within the insulation wall. Since the tapes near the insulation shield are exposed to temperatures lower than those near the conductor shield, a marked difference in wet tensile strength is expected between the inner and outer paper tapes of a well-aged cable, similar to dry tensile strength.

Unlike mechanical properties such as tensile strength and folding endurance, the degree of polymerization shows the least variability during measurements. Whereas the two former mechanical properties are related to the bulk properties of paper, DP represents a fundamental measurement. DP is related to the length of the cellulose strand (or cellulose molecules) in the paper fiber.

Although the length of these strands is affected by the source of the cellulose material and the pulping process, papers with a DP below 400 are considered too weak to perform a reliable insulation function, as an EPRI study has demonstrated [EPRI 1998a]. It is noteworthy that industry standards and specifications, such as IEC 141-1 and AEIC CS2 or CS4, do not presently require measurement of DP as a factory test (nor the other tests described in this section), so initial condition benchmarking is difficult to establish with certainty.

Paper's folding endurance is relatively sensitive to degradation at temperatures above 65°C (an uncommon situation for the vast majority of HPFF and SCFF cables under normal operating conditions) and not below this temperature. Below 65°C, the loss rate of folding endurance is not any faster than the corresponding loss rate of dry tensile strength or DP. Thus, folding endurance measurements are not so useful for operating cables, where temperatures are usually well below the rated temperature of 85°C. However, they can be useful aging indicators if cables have been overloaded for significant periods.

The magenta dye test is a staining procedure. In this test, fluid-impregnated paper is soaked in a solution of acid fuchsine that turns the paper purple. The so-called wax formed as a result of ionization does not absorb this dye.

3.6 Radiographic Inspection of Splices, Terminations, Trifurcators, and Cables

Radiographic (X-ray) inspection has been one of the most commonly used noninvasive inspection methods for detecting signs of thermomechanical behavior in HPFF cable systems.

The inspection can be performed using conventional X-ray film or digital X-ray imaging techniques. The exposure times of digital radiographic inspection are significantly shorter than those for the conventional radiographic inspection.

3.7 Partial-Discharge Measurements

Partial-discharge (PD) measurements are diagnostic tests to determine if there are localized discharges in the cable insulation caused by weak spots or localized intensification of electric field in the insulation. They can be used to verify proper installation of a cable circuit or to assess insulation aging or degradation if applied continuously or at certain intervals. Several measurement methods can be used to detect partial discharges. High-frequency current transformers (HFCTs) can be used as inductive couplers placed around the cable pipe and bonding leads, or around SCFF cable bonding leads, at multiple locations.

PD measurements can be made using on-line testing methods, where the cable is energized at rated voltage from the power system, or off-line measurements where the cable is energized from a high-voltage source, such as a variable frequency (VF) resonant test set, other than the power system. VF resonant test sets generate an ac test voltage with a frequency of 20 to 300 Hz depending on the parameters of the cable being tested and the test equipment. The output of the frequency converter is adjusted until series resonance is achieved (for example, the reactance of the inductor is equal to the reactance of the cable).

Advantages of a VF series resonant test set are:

- Minimal risk of damage if a failure occurs.
- Adjustable test Voltage. The magnitude of the test voltage is continuously adjustable, and the applied test voltage is higher than the rated system voltage to increase the chances of detecting incipient failures indicated by partial discharges.
- Elimination of electrical transients. Energization of the cable circuit from the transmission system inevitably creates transient overvoltages that are higher than the peak of the normal power frequency voltage. When the cable is energized from a VF series resonant test set, the voltage is slowly increased in a controlled manner, eliminating any energization transients. Eliminating the transients is especially important since the surge voltage protection device may need to be removed for the measurements.

The main disadvantage of using a VF test set to raise the voltage above normal operating levels is the high cost and size of the equipment, especially for long cable systems with high capacitance.

The primary advantages of on-line PD measurements are that the cable system does not have to be removed from service to conduct the tests, and the tests can be performed at normal operating temperatures. The on-line PD measurements can be performed by recording both frequency and time-domain signals from the HFCT. The measurement results can be interpreted based on laboratory test results and previous measurements on similar cable systems.

A disadvantage of PD measurements for HPFF cable systems is that signal attenuation is higher than that for SCFF and extruded dielectric cables, such that the measurements are presently only effective for detecting PD near joints or terminations. In addition, because the joints are contained within a steel casing, installing PD sensors is difficult. Additional information on the relative effectiveness of PD measurements on different cable types is described in an EPRI report [EPRI 2006].

Off-line PD measurements can also be performed by ultrasonic PD detection. The principle of acoustic PD measurements is to detect mechanical vibrations on the cable caused by shock waves created by partial discharges. The acoustic to electrical transducer can be moved along the cable—for example, in a tunnel—until the location with the highest acoustic signal is detected and the measurements are carried out at this location by positioning the transducer at 0, 120 and 240° angles from the cable axis. The magnitude, frequency, and synchronization of the signals with the power frequency are used to perform an assessment of the acoustic signals.

3.8 Pressurization System Inspection

Laminar dielectric cable systems are designed to operate under positive fluid pressure at all times. On HPFF circuits, pumping plants are used to maintain the fluid pressure within a preset operating range. When the system pressure drops below or rises above the preset range, fluid is introduced into or relieved from the hydraulic circuit. Abnormal conditions, such as high or low pressures, frequent pumping, and low fluid level are alarmed. Though the pressurization units are designed for automatic operation, periodic maintenance and testing are required to ensure that all components are operating properly.

Older pressurization units were equipped with pressure recorders requiring chart changes about once a week. During these regular visits, the operator was expected not only to examine the charts for unusual pump or relief valve operations but also to visually inspect the area for potential problems and arrange for necessary repairs. Newer pressurization units are equipped with electronic pressure transducers, programmable logic controllers, and human-machine interface displays, as well as remote monitoring systems for most critical parameters of the pressurizing system. Alarms are annunciated via a utility's supervisory control and data acquisition (SCADA) system.

Most HPGF cable circuits incorporate gas supply cabinets for maintaining proper pressure levels. The cabinets contain a pressure gauge, high- and low- pressure alarm switches, nitrogen bottles, and a pressure regulator. The bottles are not normally connected to the circuit but are there in the event of a low-pressure alarm. Once a year, the alarm circuits should be tested for proper operation. Remote monitoring systems are also available for HPGF circuits. Gas analysis sampling should also be done on these circuits.

SCFF cable circuits operate at pressure levels based on the maximum hoop stress of the cable sheath or the design of the sheath reinforcement and the cable route elevation profile. Maintenance procedures for these systems vary depending on the type and location of the pressurizing units. Most cable circuits rely on prepressurized fluid reservoirs connected at the termination ends and at intermediate stop-joint locations, as required to maintain positive fluid pressure throughout the circuit under all operating conditions. Abnormal fluid pressures are alarmed, as with the other laminar insulation cable systems. A positive feature of SCFF cable systems with prepressurized reservoirs is that each phase is usually pressurized separately. This allows monitoring of differential pressures between phases, which can provide early detection of leaks during individual phases. For SCFF cable systems using prepressurized reservoirs and differential pressure alarms, fluid pressure alarm systems should normally be tested annually. SCFF cable systems pressurized with pumping plants, as with submarine cable circuits, should have their fluid-pressurizing systems inspected monthly.

3.9 Buried-Pipe Corrosion and Cathodic Protection System Inspection

This section applies only to pipe-type cables with impressed current cathodic protection systems, since cathodic protection systems are rarely applied to SCFF cable systems and sacrificial anode systems are also rarely applied.

3.9.1 Potential Surveys

Cathodic protection facilities should be monitored to ensure that the required level of protection is in force and the system is operating reliably. A variety of methods exist for determining whether a structure is being effectively protected by a cathodic protection system. Performance can be monitored by measuring the dc potential of the structure, the current input, or both. The potentials of the surfaces of a structure with respect to a reference electrode are the most widely used criteria for determining whether a structure is being effectively protected by a cathodic protection system. For an impressed current system, the monitoring also includes rectifier readings (such as voltage, ampere, and tap settings) and inspection. Some methods may not be practical for certain conditions and environments. Engineering judgment should be used to determine which methods are required and how often tests should be performed to satisfy the criteria. In some situations, a single criterion for evaluating the effectiveness of cathodic protection is not satisfactory. Often a combination of criteria is needed even for a single structure.

Table 3-2 shows some of the criteria that can be used to determine the adequacy of a cathodic protection system, with respect to the required negative potential between the pipe and a copper/copper sulfate reference electrode.

Table 3-2
Criteria for Cathodic Protection

Structure	Structure Potential to Copper/Copper Sulfate Reference Electrode	Cathodic Polarization Potential Between Structure and Stable Reference Electrode	Reference
Underground or submerged steel and cast iron pipe	-0.850 Vdc or more negative	0.1 Vdc	NACE RP0169
Underground or submerged steel structures	-0.850 Vdc or more negative	0.1 Vdc	NACE RP0285

The aboveground potential readings indicate the corrosive activity on the structure and the effectiveness of the cathodic protection system. The readings can be measured at all aboveground or manhole connection points and test stations along the cable route. The readings can also be measured by a close interval survey (CIS). This potential survey uses external corrosion direct assessment methodology to identify and define diminished cathodic protection and external coating damage of buried steel pipes.

3.9.2 Structure Connection (Bond) Current Measurements

When there is stray dc current interference between a secondary structure and the primary one of interest, an electrical connection may be needed to direct the current from the secondary structure. This electrical connection is called a bond. The resistance bond check is an operational check of two metallic structures connected with a semiconductor or resistor to ensure that the structures affected by the bond are maintained at proper potentials. The bond can be a 100% bond or a resistance bond. The 100% bond allows all the current collected on one structure to flow back to the source. The resistance bond allows only a portion of the current to flow through the bond back to the source. The purpose of the resistance bond is to limit the amount of secondary current that can collect on a structure so that the potential does not exceed the maximum allowable, or if the primary structure does not require cathodic protection. The resistance bond check is performed while the cathodic protection system(s) is operating. The potential measurements are compared to previous readings to indicate trends.

3.9.3 Stray DC Current Measurements

In an impressed current system, electrical shielding/interference occurs when a secondary structure in the vicinity of the cathodic protection system interferes with the expected distribution of current to the cathodically protected primary structure (that is, a cable pipe). The secondary structure provides an alternate low-resistance path. For example, stray dc currents from poorly insulated dc-powered railway systems can follow the underground system as a low-resistance path back to their source. Interference may be minimized by ensuring careful design of the primary cathodic protection system, operating at the lowest possible current density, and maintaining the greatest possible separation between the primary structure to be protected and

the secondary interfering structure, and between the ground beds or anodes and the secondary structure.
The stray dc currents can affect the cathodic protection system on a nearby primary structure since cathodic protection currents sufficient to protect other parts of the structure may not be adequate to protect it at the discharge point where the stray dc currents travel back to their source. Tests must be performed to identify the stray current interference so that protective measures can be taken. A current interrupter is inserted into the cathodic protection circuit of the secondary structure that may be causing the stray current problem. The potential of nearby structures is then measured with the current on and off. Potentials are measured where the structures are closest. If the potential of the primary structure becomes less negative with the current on, cathodic interference is identified and corrective measures are required. In some cases, this could entail excavating the cable pipe and repairing the pipe coating in the vicinity of the measured interference.

When interference is found, it is necessary to determine if the point of crossing from one structure to the other is actually the point where current is the greatest. This can be done by moving the CIS reference electrode in the vicinity of the crossing. Generally, the point of maximum current discharge corresponds to the point of the greatest voltage change. “Accidental” interference can be a serious problem. Information obtained in these analyses will help determine the need for and required level of cathodic protection.

3.9.4 Remote Cathodic Protection Monitoring

Cathodic protection real-time remote monitoring has been used in the industry. The system generally consists of monitoring and communication devices, a centralized database, and data processing software. The monitoring device is installed next to the cathodic protection facilities. The monitored data are communicated to the database via an existing SCADA system, a “drive-by” remote monitoring vehicle, or cellular, radio, or satellite communication systems. The data are processed at the locations of the monitoring device and the remote database. An alarm system can be established to notify system users if the monitored data are outside of user-configured limits. Examples of the measurements include rectifier dc output voltage, dc output current across a shunt of known resistance, input ac voltage, structure-to-soil potential located at a distance from the cathode protection equipment, ac/dc measurement at critical bonds, electrolyte level of polarization cells, dynamic stray currents, and drainage connections.

3.9.5 Aboveground Coating Surveys

After the pipe has been installed, several techniques are used in the pipeline industry to inspect coating integrity. Some techniques need to be refined to be used in pipe-type cables because of the grounding paths encountered in power systems. Direct current voltage gradient (DCVG) surveys, alternating current voltage gradient (ACVG) surveys, close interval surveys, ac attenuation surveys, and Pearson surveys are examples of inspection methods for buried coated pipes to evaluate coating conditions, locate coating flaws, and assess flaw severity. Combining these inspection methods enables detection of coating flaws and cathodic protection adequacy.

3.9.6 DCVG Surveys

DCVG surveys are used to locate and size coating holidays. In DCVG measurements, an interrupted dc signal is injected into the steel pipe to distinguish the interference with other dc current sources such as cathodic protection currents or other stray currents. The voltage gradient created by the current traveling to the holiday is measured with one probe over the pipe and the other probe perpendicular to the pipe as far as is comfortable. The level of voltage gradient indicates the flaw location and holiday size. The location precision can be within 1 m. DCVG is suitable for complex piping arrangements such as those in urban areas and for piping beneath reinforced-concrete paving and near other power lines.

3.9.7 ACVG Surveys

ACVG surveys are also used to locate and size coating holidays. An ac signal using a low-frequency transmitter is applied to the pipe, and signal direction is measured above the pipe at specific intervals. Once the holiday is passed, the direction is reversed and at the holiday location, the magnitude should be 0. ACVG surveys can generally be carried out more quickly than DCVG surveys. ACVG surveys can work in various soil conditions and are more sensitive over pavement than other voltage gradient surveys. However, they are less susceptible to existing or stray direct currents. They are highly accurate in locating defects and are also suitable for complex piping arrangements, such as those in urban areas.

3.9.8 CISs

Close interval surveys are used to determine cathodic protection levels, electrical contact with other structures, areas of current shielding, and large coating holidays. In CIS measurements, the profile of potential (IR) between the steel pipe and a portable reference cell electrode above the pipe is recorded along the entire route. CISs can identify possible interference areas and shorted casings.

3.9.9 AC Attenuation and Pearson Surveys

AC attenuation and Pearson surveys are used to locate large coating holidays. An ac signal using a low-frequency transmitter is applied to the pipe for the ac attenuation surveys. Measurements can be taken at large intervals (50 ft, 100 ft, or larger) and over various types of covers (concrete, rocks, pavement, and water) without detrimental effects. The surveys can be performed very quickly to evaluate bonds, shorts, or other concerns and then followed by more detailed and time-consuming surveys.

During Pearson surveys, a signal of various frequencies can be applied to the pipe. The audio frequency signal and its intensity are measured by a receiver, indicating coating flaw location. Pearson surveys can locate coating defects and foreign metallic objects close to the pipe that can cause a potential gradient in the soil. This method may be affected by nearby ac power lines or other electrical interference.

3.10 Detection of Jacket Faults and Sheath Voltage Limiter Failure in SCFF Cable Systems

For SCFF cable systems, one of the most expensive maintenance activities is the periodic testing of cable jackets (serving tests). Jacket damage can result in water ingress and sheath corrosion. Jacket faults can also cause electrical safety hazards as sheath currents are injected into the ground, possibly causing high local ground potential rises and step and touch potentials. If the effectiveness of the special bonding systems to improve ampacity is lost, cables can also overheat. Industry practice is to apply a dc test voltage between the sheath and ground to verify integrity. The test is expensive and disruptive because it requires line outages, all manholes must be entered to change and restore sheath bonding connections, and for double circuits sharing a duct bank, safety hazards can exist due to induction.

There would be many benefits if such maintenance could be eliminated (or the interval increased) and jacket condition could be measured remotely, perhaps in real time. Possible methods include placing small current transformers around each sheath bonding connection and each sheath voltage limiter (SVL) connection, to check for irregular readings indicative of a jacket fault or a SVL failure. Currents and phase angles would be relayed to a hub and then to a control center for action, if needed. Alternatively, alarm levels could be established so that only alarm signals would be telemetered to a control center. Of course, the sheath currents vary proportionately to load currents, so conductor currents would also need to be considered, as well as the effects of cross-bonding interconnections. It is recommended that jacket tests and SVL inspections be done every five years as a maximum.

4
A METHOD FOR ON-LINE CABLE INSULATION DISSIPATION FACTOR MEASUREMENTS

4.1 Dissipation Factor

Insulation losses are fundamentally a result of charge carrier movement when the insulation is under electric field stress at power frequency. The charge carriers include ions and electrons. The ions are part of impurity, contamination, and oxidation products within the insulation that is a combination of paper and insulating fluids for pipe-type cables.

The insulation dissipation factor is defined as the amount of dielectric losses divided by the voltamperes of the charging current, both per unit of cable length (Eq. 4-1)

$$\text{Dissipation Factor} = \frac{P}{V\,I} \qquad \text{Eq. 4-1}$$

where P = dielectric losses (W/ft or W/m); I = cable charging current (A/ft or A/m); V = voltage (line to ground) (V). The dissipation factor is typically between 0.2% and 0.3% for high quality fluid-impregnated paper insulation used in extrahigh voltage transmission cables at room temperature.

The dielectric of a cable can be represented by an equivalent circuit of one capacitor (C) and one resistor (R), as shown in Figure 4-1. When an ac voltage (V) is applied to the insulation, the actual total charging current (I) flowing through the insulation is a vector sum of the ideal charging current (I_C) and resistive loss current (I_R). Figure 4-2 shows the phasor diagram of Figure 4-1 where Φ is the phase angle between the voltage (V) and the actual total charging current (I), and δ is the phase angle between the actual total charging current (I) and the ideal charging current (I_C). The dissipation factor is numerically equal to tan δ. Then the dissipation factor (tan δ) in terms of I_R and I_C is:

$$\tan\delta = \frac{I_R}{I_C} \qquad \text{Eq. 4-2}$$

where I_R is V/R and I_C is V/(1/ωC), then

$$\tan\delta = \frac{1}{\omega RC} \qquad \text{Eq. 4-3}$$

where ω is the angular frequency of the voltage.

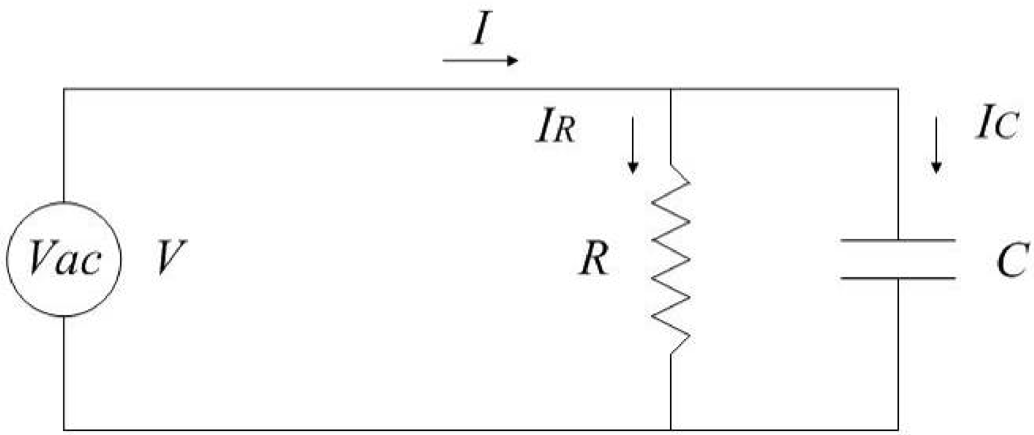

Figure 4-1
Equivalent Circuit of Cable Dielectric

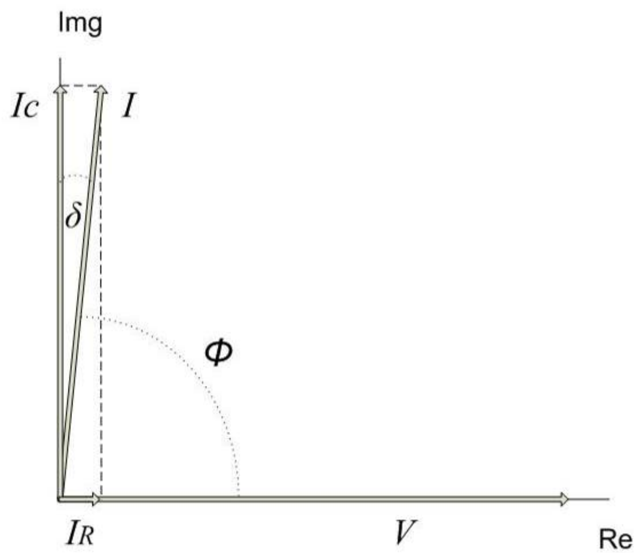

Figure 4-2
Phasor Diagram of Voltage and Currents of Cable Dielectric

The phase angle (δ) can also be derived from the waveshape shift between the total current (I) and the charging current (I_C). The charging current (I_C) is 90º apart from the applied voltage (V). The phase angles are shown in Figure 4-3.

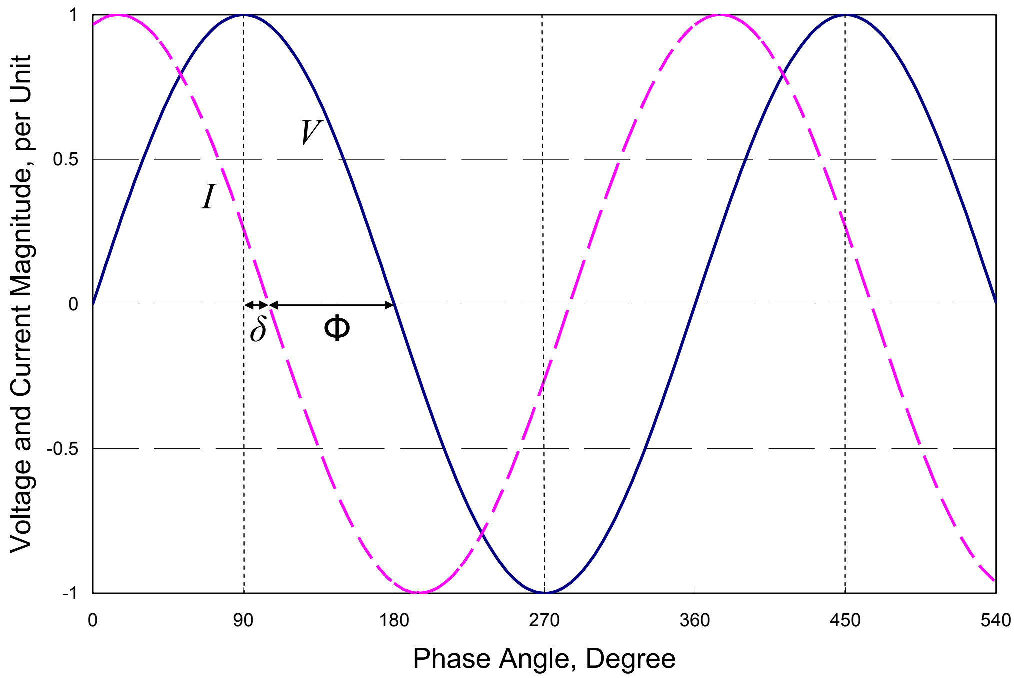

Figure 4-3
Waveshapes of Voltage (V) and Current (I) in Figure 4-1

As demonstrated above, the quantity to be measured for the dissipation factor is the tangent of the angle between the actual cable charging current with both capacitive and resistive components and the ideal charging current with no power losses. Then the losses (P) of the cable insulation can be estimated by Equation 4-4, which shows that the losses are directly proportional to the dissipation factor.

$$P = \omega C V^2 \tan\delta \qquad \text{Eq. 4-4}$$

The capacitance of a cable can be determined by the following equation.

$$C = \frac{\varepsilon_r}{18 \ln D_i / D_c} \times 10^{-3} \, \mu F / m \qquad \text{Eq. 4-5}$$

where ε_r is the dielectric constant of cable insulation; D_i is the diameter over cable insulation; and D_c is the diameter over conductor shield. The typical values of ε_r are 3.5 and 2.8 for impregnated paper insulation and for impregnated paper-polypropylene-paper insulation, respectively.

4.2 Field Circuit Dissipation Factor MeasurementsInsulation dissipation factor measurements indicate the average condition of cable high-voltage insulation for the entire length of cable, splices, and terminations being measured. This type of diagnostic test is well suited for detecting uniform deterioration of cable high-voltage insulation.

The dissipation factor of fluid-impregnated cable insulation remains relatively constant with time provided that there is no thermal decomposition of the insulation or that no contaminants are introduced into the cable system (such as water or peroxides shipped with the pipe-filling fluid). If thermal aging of the cellulose insulation does occur, carbon oxides (carbon monoxide and carbon dioxide) as well as water are produced. The water, in turn, increases the dissipation factor of the insulation. Consequently, the cable insulation dissipation factor is an indirect measurement of cable thermal aging. Test results indicate that there is a sharp upturn of the insulation dissipation factor as cables approach end of life [EPRI 1998a].

The insulation dissipation factor for fluid-impregnated paper is lowest at approximately 65 to 75ºC and increases for temperatures above and below, as shown in Figure 4-4. Consequently, an estimation of the cable temperature when the dissipation factor is measured is useful in evaluating the results of the measurements. HPFF cable system pipe or fluid temperatures may give a good indication of cable insulation temperature.

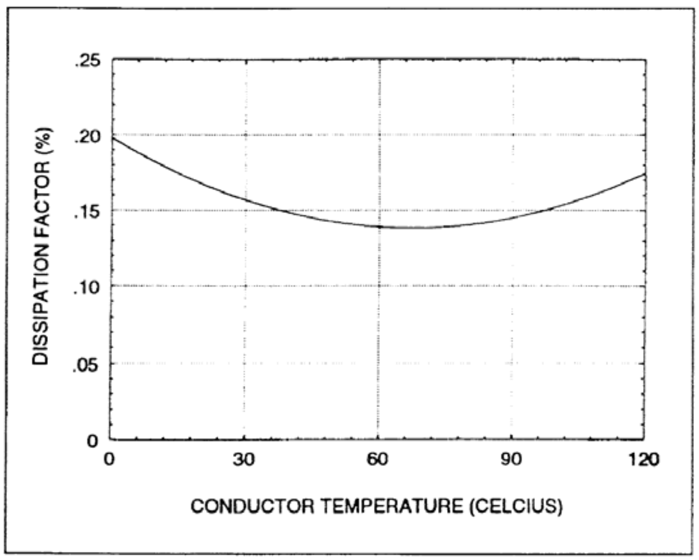

Figure 4-4
Typical Variation of the Cable Dissipation Factor with Temperature

The dissipation factor values may increase with applied voltage, because the increased electric field forces the ions to move more freely. However, space charge or interfacial polarization may occur, blocking the movement of ions, resulting in a decrease of the dissipation factor with the increase of the electric field. Therefore, any marked changes with voltage may implicate ion contamination. It is not desirable to measure the dissipation factor at a lower voltage than the nominal line-to-ground voltage in the field.

The AEIC CS2 specification for HPFF cables [AEIC 1997] and AEIC CS4 specification for SCFF cables [AEIC 1993] contain dissipation factor limits for different cable conductor/insulation temperatures. The limits can be used as a basis for evaluating the field dissipation factor measurements. However, the most suitable basis for interpreting the results of the dissipation factor measurements is to compare the field measurements with the initial factory dissipation factor measurements at the same temperature. This is because the dissipation factor of fluid-impregnated paper insulation depends on the moisture content of the paper at the time of impregnation and on the density of the paper tapes. Higher-density paper tapes have higher impulse breakdown strength, but the dissipation factor increases with the density of the tapes. Consequently, the dissipation factor of new cables varies from one manufacturer to another and, to a lesser extent, on the manufacturing process at the time that the cable was manufactured.

Repeating dissipation factor measurements every three to five years is one of the better methods for identifying significant changes in the condition of the cable insulation. This method is particularly useful when there is a significant variation in dissipation factor values for the three phases of the cable circuit.

Testing experience and a review of factory test data show that the dissipation factor for different reels of cable may vary as much as 20%; however, the composite dissipation factor for installed cable systems should not deviate more than 15%, because the field dissipation factor measurements yield the average value for multiple reels of cable.

Most transmission pipe-type cable systems ground the metallic shield at multiple points—for example, where the skid wires contact the cable pipe. For field dissipation factor measurements, it is desirable to have the cable charging current flow through the dissipation factor measurement instrument if a traditional bridge method is used, as in the factory tests on cable reels. However, this approach is impractical for field installations because of the multiple insulation shield grounds. To overcome this problem, the EPRI off-line field dissipation factor measurement method was developed, as described below.

The method is not well suited for detecting localized insulation defects for typical-length transmission cables because increased losses at local defects are "averaged out" by the losses of the majority of the cable circuit. The dissipation factor measurements do not address discrete components such as splices, terminations, or any isolated defects. For relatively short cable system lengths, the dissipation factor measurements may detect some localized defects.

Although dissipation factor measurements may indicate that the majority of the cable insulation is in good condition, such test results do not rule out the possibility of deterioration of short sections of cable or joints. Other diagnostic tests should be used in combination with insulation dissipation factor measurements when assessing the condition of laminar dielectric cable systems.

4.3 EPRI Field Dissipation Factor Measurement System

Dissipation factor measurements are routinely performed on different types of power system equipment as a diagnostic test. However, capacitance charging currents are usually much higher for laminar dielectric cables, which presents difficulties. EPRI developed an instrument for measuring the insulation dissipation factor of transmission cable systems in the field at rated voltage [EPRI 1993]. The prototype unit, which was developed in 1992, has been used to perform field dissipation factor measurements on numerous HPFF and SCFF transmission cable systems in North America. The equipment considers the high capacitance charging power requirements of most cable circuits. Figure 4-5 presents a schematic diagram of the dissipation factor measurement.

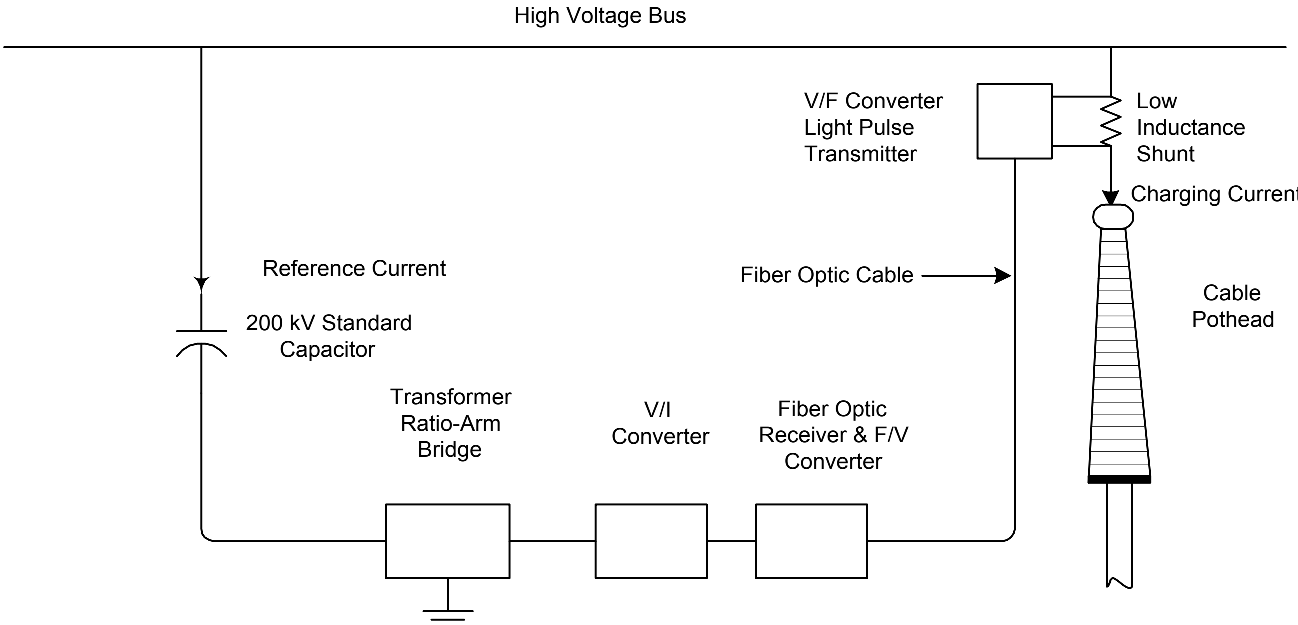

Figure 4-5
Dissipation Factor Measurement Schematic Diagram

As the figure shows, the high-voltage cables are energized by the power system at rated voltage or by a separated source at one of the two cable terminations (potheads). The insulation dissipation factor is measured by a modified transformer ratio-arm bridge [EPRI 1993]. The bridge measures the phase angle difference between the charging current flowing through the high-voltage cable insulation and the reference current that flows through a standard capacitor, which provides a reference current 90ºout of phase with each of the three voltages applied to the three cable phases.

Commercially available transformer ratio-arm bridges or Schering bridges are commonly used in high-voltage laboratories or manufacturing plants to measure the cable dissipation factor. Because most transmission cable systems are grounded at multiple points, the bridge circuit was modified for the field measurement of cable systems so that the cable charging current would flow through one winding of the bridge. The instrument measures the charging current through a low-inductance shunt. A voltage-to-frequency (V/F) converter and a light pulse transmitter are used for the analog fiber-optic cable to transmit this information. The frequency signal is then converted to voltage through a fiber-optic receiver and frequency-to-voltage (F/V) converter, then to current through a voltage-to-current (V/I) converter, and transmitted to the transformer ratio-arm bridge at ground potential to measure the phase angle between the cable charge current and the charging current in the standard capacitor.

A compact high-voltage standard capacitor with polypropylene insulation is used. The capacitor is purposely selected to have a very low dissipation factor to obtain the required reference current.

Although the cable circuit is energized only at one cable end to eliminate losses caused by load current, the cable charging current still creates losses in the cable conductor. Since the dissipation factor measurement considers only the dielectric losses, the bridge readings need to be adjusted to account for the resistive conductor losses. It is also a standard measurement procedure to disconnect any surge arresters at the far end of the cable circuit to eliminate unnecessary loading, although the losses in the surge arresters are negligible in most cases.

Measurements using the single-phase instrument are sometimes time-consuming and require planned circuit outages. Typically, the dissipation factor measurements on the three phases of an underground transmission circuit require from 5 to 10 hours depending on the availability of utility line switching personnel and the time necessary to obtain line clearances. Appendix A provides a detailed guide for field laminar dielectric cable dissipation factor measurements using the EPRI-developed instrument.

It will be a major improvement in the measurement process if the instrument is expanded so that measurement is possible on all three phases of the underground line at one time. This will ultimately reduce the time to perform the measurements by approximately 50% and will significantly reduce the cost of having crews at both ends of the circuit. It will also reduce the number of circuit-switching operations by two-thirds. The transformer ratio-arm bridge of the EPRI-developed instrument can be used to perform measurements on all three phases. A high-voltage standard capacitor must be connected to each of the three phases. Three sets of equipment must also be connected to the top of each cable termination to transmit a signal to ground level via a fiber-optic cable. Two new V/I and fiber-optic analog data links must be fabricated. An attempt was made by EPRI in 2005 to expand the EPRI field dissipation factor measurement instrumentation with three-phase measurement capability. However, the plan was not executed.

4.4 On-Line Field Dissipation Factor Measurement Issues

The EPRI-developed instrument makes it possible to measure the dissipation factor in the field on many installed cable circuit configurations. As discussed above, an obvious disadvantage of the system is that the measurements need a circuit outage and are time-consuming. The system also needs a standard capacitor connected to the phase conductor. Adding such a device permanently to the system would be costly and have high maintenance requirements.

The ultimate goal of dissipation factor measurements is to determine the insulation integrity of the cable system through measuring insulation losses at a rated voltage. On-line insulation dissipation factor measurements have been discussed to develop trending, starting by comparing the measured dissipation factor values to the original factory tests. On-line dissipation factor measurements are attractive to minimize the need for line outages. However, the challenge of on-line monitoring is the fact that the circuit is in operating condition. Therefore, the load current of each phase conductor creates additional losses, compared with an unloaded circuit with only the charging current, as in the off-line test. The load current dependent losses include:

- Conductor losses as determined by the ac resistance of the conductor as a function of conductor materials and construction. Conductor losses are also referred to as I^2R_{ac} losses, where I is the conductor current and R_{ac} is the equivalent conductor ac resistance at the operating temperature. Correction for pipe effects for a pipe-type cable system, conductor segmenting, and skin/proximity effects must be taken into account to determine the conductor losses.

- For pipe-type systems, steel pipe losses, also referred to as hysteresis losses and eddy-current losses, and as determined by the return currents in pipes. For pipe-type cables, the pipe losses can be as high as 50% of the conductor losses. For pipe-type systems, helically applied skid wire and metallic tape losses are determined by the induced currents and eddy currents, since the shield for pipe-type cables is normally grounded at multiple points. For pipe-type cables, the sheath current losses are relatively small due to the high shield resistance, and the eddy-current losses are mostly negligible.
- For SCFF cable systems, losses in cable metallic shield/sheaths.

As discussed, the dielectric losses of the cable insulation are a function of the square of the operating voltage (Equation 4-4). For conventional impregnated paper insulation, at 69 kV and below, the dielectric losses are negligible. The losses account for about one-third of losses at 345 kV and about half at 500 kV for pipe-type cables with conventional Kraft paper insulation. For paper-polypropylene-paper insulation, the losses are reduced to less than 10% of the total at 345 kV and slightly more than 10% at 500 kV. For pipe-type cables, the shield and skid wire losses are usually less than 5% of the total losses.

In addition, some external losses and variances may influence the total loss monitoring system:
- Loss variations caused by temperature variation along the cable circuit
- Surge arrester losses that are mostly negligible
- Losses on termination external surfaces that are affected by moisture in the external environment

4.5 A New Concept for On-Line Cable Insulation Dissipation Factor Measurements

The new concept of an insulation loss monitoring system uses quantities measured from both terminals of a cable circuit, such as voltages, currents, and phase angles, to determine the dielectric losses of the cable insulation. With present synchronization and communication technologies, measurements can be made at an exact moment from both cable terminals. The data can then be transmitted to a central data processing unit to determine the dissipation factor of the cable circuit. A schematic diagram of a single-phase cable circuit is shown in Figure 4-6.

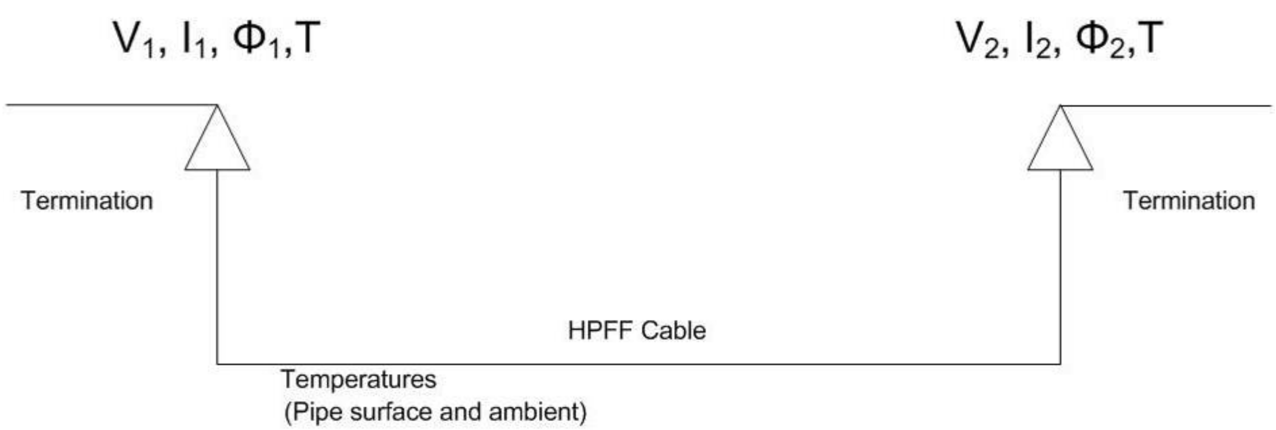

Figure 4-6
Schematic Diagram of a Single-Phase Cable Circuit—System Inputs

4.5.1 System Inputs

The quantities that can be obtained readily from each end of a cable circuit are voltages (V_1 and V_2), currents (I_1 and I_2), and phase angles (Φ_1 and Φ_2), including waveshape and magnitude information. With present synchronization and communication technologies and accurate satellite clocks, measurements can be made from both ends of the circuit at an exact time (T), and data transmitted to a central data processing unit. Temperatures, for example, on the pipe or SCFF cable surface can also be measured along the circuit.

4.5.2 System Components

At each end of a cable circuit:

- Voltage transducers (power frequency, all phases)
- Current transducers (power frequency, all phases)
- Phase angle transducers (power frequency, all phases)
- Signal conditioning
- Data acquisition unit
- Power source

At locations near and far from the pipe surface:

- Temperature sensors for pipe or cable surface and for ambient air and soil

For synchronization and communications:

- Synchronized measurements from both ends of the cable circuit
- Communications from signal transducers to the central data processing unit

For data processing, circuit modeling, and display:

- Data processing unit and display
- Software for data processing and alarm systems

4.5.3 Circuit Modeling

A data processing unit is required to calculate the following quantities from the measured data and system modeling to derive a value of insulation losses for the cable circuit loaded and energized by the system voltage.

- Power losses going into a cable circuit
- Power losses going into the load supplied by the cable circuit
- Conductor losses
- Steel pipe losses
- Skid wire losses

- Sheath losses
- Losses through grounding loops
- Insulation temperature
- Losses caused by temperature variation
- Insulation losses
- Dissipation factor (tan δ)
- Trending and alarms

4.5.4 System Requirements

Installation and operation:

- The monitoring system is designed for HPFF and SCFF cable systems from 138 kV to 345 kV.
- The transducers for voltage, current, phase angle, and temperature measurements are installed in an outdoor environment.
- Installation of the monitoring system must minimize the downtime of the cable circuit to be monitored, if any is required.
- Installation and operation of the monitoring system components do not affect the operation of the cable circuit.
- The monitoring system provides protection from high-voltage, initial charging current, transient overvoltage, and environmental impacts.

Sensitivity and accuracy:

- The phase angle measurement sensitivity to determine the dissipation factor for a fluid-impregnated cable circuit must be in the range of 0.02 to 0.1 milliradian. Typical values of the dissipation factor for fluid-impregnated paper and paper-polypropylene-paper insulation are 0.2% and 0.1% radian, respectively, which correspond to 0.12 and 0.06° of δ.
- Accordingly, the measurements of voltages, currents, and phase angles from both ends of a cable circuit must all be accurate enough to meet the dissipation factor measurement requirements.
- The system must apply correction factors for all noninsulation losses in the measuring systems.

Output:

- The system must display measurement results, including trending and alarms.

4.6 Feasibility Study of On-Lin Field Cable Dissipation Factor Measurement

4.6.1 Pipe-Type Cable Example

This section demonstrates the on-line dissipation factor measurement system concept using a pipe-type cable example [EPRI 1992].

Cable circuit information:

- System voltage: 345 kV
- Voltage frequency: 60 Hz
- Loss factor: 0.62
- Circuit total length: 52,800 ft (16,100 m)
- Two identical circuits in parallel in the same trench
- Number of manholes: 9
- Shunt reactors: none

Cable information:

- 2500 kcmil (1267 mm^2) segmental copper conductor, 1.824 inch diameter, 5.343 μΩ/ft dc resistance at 85ºC
- Impregnated Kraft paper insulation, 0.905-inch thickness, 3.5 dielectric constant, 0.23% dissipation factor, 600Cº-cm/W thermal resistivity
- Stainless steel shield tapes (1), 0.005-inch thickness, 0.75 inch wide, and 0.25-inch overlay
- Stainless steel skid wires (2), 0.1by 0.2 inch, 3-inch lay
- Mineral oil
- Steel pipe, 10.75-inch outside diameter and 10.25-inch inside diameter,0.070-inch polyethylene coating (Pritec), 350 Cº-cm/W thermal resistivity

Installation dimensions:

Figures 4-7 and 4-8 show the installation dimensions and image of the cable circuit example.

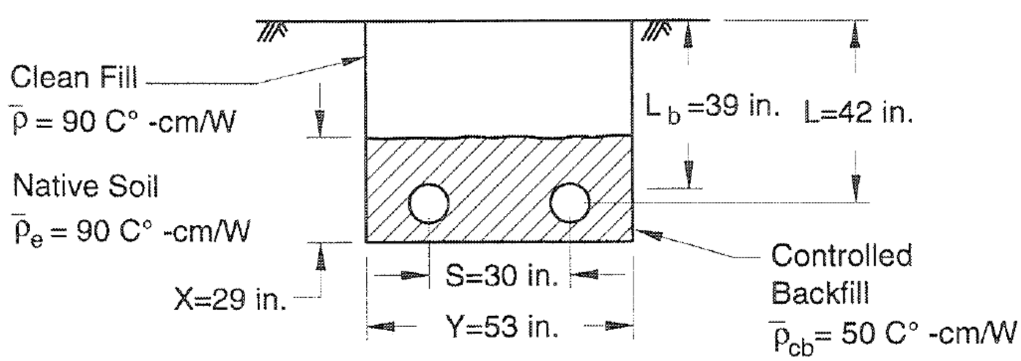

Figure 4-7
Installation Dimensions of the Cable Circuit Example

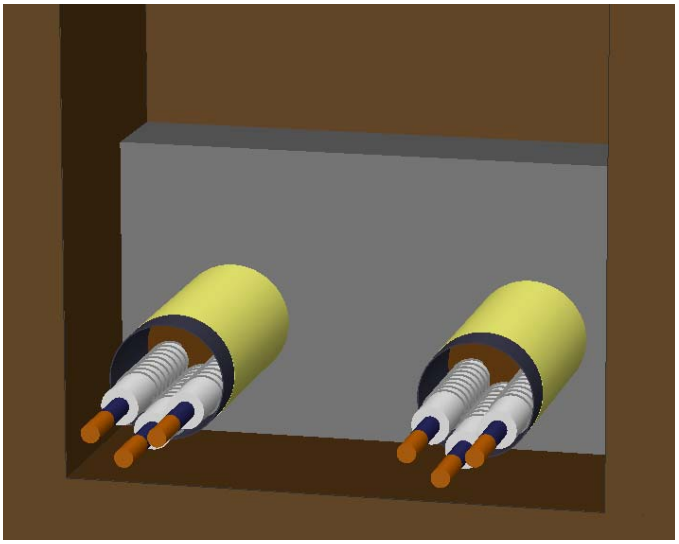

Figure 4-8
Three-Dimensional Image of the Cable Circuit Installation Configuration

Calculated parameters per phase of each of the two cable circuits:

The example circuits were simulated in the EPRI-developed Underground Transmission Workstation. The following parameters were obtained through the simulation and additional calculations [EPRI 1992, Chapter 5; and EPRI 2007, Chapter 11].

- Cable insulation capacitance: 86×10^{-3} μF/1000 ft.
- Charging current: 6.77 A/1000 ft, or total charging current: 357 A.
- Inductance: 48 μH/1000 ft.
- Conductor ac resistance for cables in pipes: 6.305 μΩ/ft (a correction factor of 1.5 was used). This value is used to include conductor losses in the study.
- Total shield and skid wire resistance: 56,040 μΩ/ft.
- Mutual reactance between conductor and shield/skid wire: 19.8 μΩ/ft.
- Shield/skid wire circulating current increment: 0.0013.
- Shield/skid wire equivalent ac resistance considering loss increment in pipes: 0.010 μΩ/ft (a correction factor of 1.5 was used). This value is used to include conductor and shield/skid wire losses in the study.
- Pipe loss increment: 0.575 (cradled configuration assumed).
- Pipe equivalent ac resistance: 3.072 μΩ/ft. This value is used to include pipe losses in the study.
- Total ac resistance: 9.387 μΩ/ft. It is a sum of the conductor ac resistance for cables in pipes, the shield/skid wire equivalent ac resistance considering the loss increment in pipes, and the pipe equivalent ac resistance, to include total ac resistance for loss calculations.
- Allowable total current: 937 A rms.
- Allowable real current: 867 A rms.

4.6.2 Equivalent Circuit for Circulation

One phase of the cable circuits was simulated in a circuit analysis program. One cable was represented by a π equivalent circuit as shown in Figure 4-9. Cable conductor inductance is not considered in the equivalent circuit since the inductance is considerably smaller than the resistance in series. In the figure,

R_I is cable insulation resistance;
C_I is cable insulation capacitance;
R_C is cable conductor ac resistance;
R_S is cable shield equivalent ac resistance;
R_P is equivalent ac resistance for losses in pipe;
V_{AC} represents the voltage source applied at one end of the cable;
R_L and L_L represent the resistive and inductive load, respectively, at the other end of the cable.

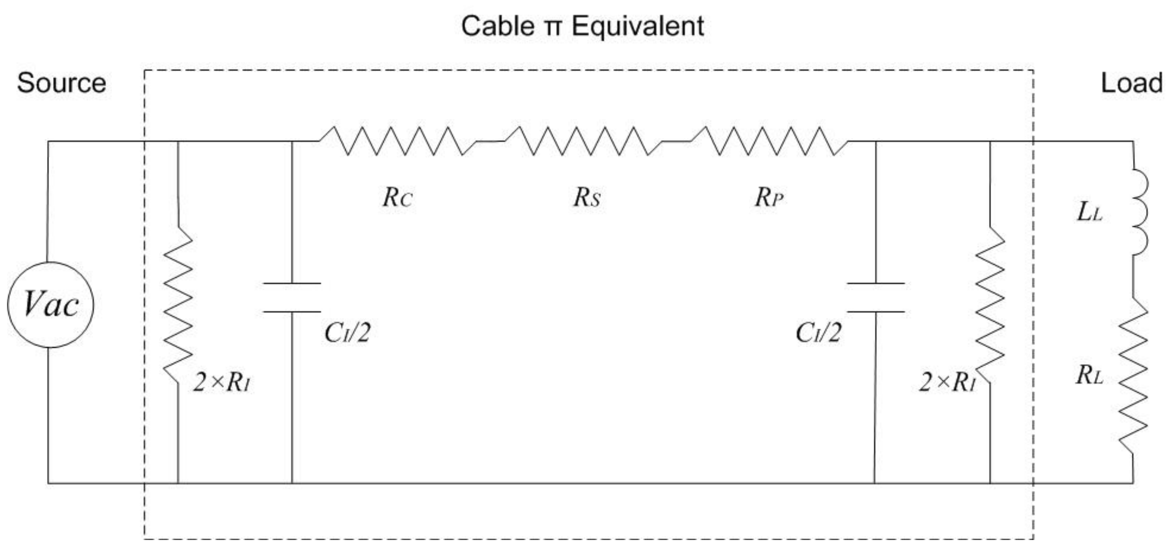

Figure 4-9
Equivalent Diagram of One Phase Cable of the Example Circuit

Values of the parameters are obtained from the circuit information given and are listed in Table 4-1.

Table 4-1
Values Used in the Equivalent Circuit in Figure 4-9

Parameter	Value	Unit	Comment	Simulation Case
V_{AC}	281.691	kV peak	345 kV nominal	All
C_I	4.54	μF	Determined by cable geometry and length and insulation material	All
R_I	254	kΩ	Determined by given tan δ—Equation 4-3	Cases 1, 2, and 3
R_I	203	kΩ	Determined by given tan δ—Equation 4-3	Case 4
R_C	0.33	Ω		All
R_S	0.0005	Ω		All
R_P	0.16	Ω		All
R_L	∞		Open load	Case 1
L_L	∞		Open load	Case 1
R_L	230	Ω	Selected to produce maximum allowable real current	Cases 2, 3, and 4
L_L	0	H	Selected to produce 1.0 power factor load	Case 2
L_L	0.3	H	Selected to produce 0.9 power factor load	Cases 3 and 4

4.6.3 Simulation Results

Case 1: Simulation Without Load (Open Circuit)

The simulation was first performed for an open circuit by disconnecting the load from the cable load side. This case represents the off-line dissipation factor test as performed using the EPRI-developed instruments described in Section 4-3.

Figure 4-10 shows the plots of source voltage (V_1) and current (I_1) as indicated in Figure 4-6. The phase angle (Φ_1) between V_1 and I_1 is 89.852º. Then the real power going into the open circuit (P_1) is determined by Equation 4-6.

$$P_1 = V_1 \times I_1 \times Cos(\Phi_1) \qquad \text{Eq. 4-6}$$

This power is consumed by the cable and can be divided into the real power consumed by the conductor resistance, sheath loss, and pipe loss (R_{TS}—total series resistance) due to the charging current and the real power loss by the insulation. R_{TS} is a sum of R_C, R_S, and R_P, as shown in Figure 4-9. The power consumed by the total series resistance can be estimated by Equation 4-7, assuming that half of the input current is going through the series resistance.

$$P_{TS} = R_{TS} \times (\frac{I_1}{2})^2 \qquad \text{Eq. 4-7}$$

Tan δ is then determined by Equation 4-8 as derived from Equation 4-1.

$$Tan(\delta) = \frac{P_1 - P_{TS}}{V_1 \times I_1} \qquad \text{Eq. 4-8}$$

Table 4-2 summarizes the simulation results.

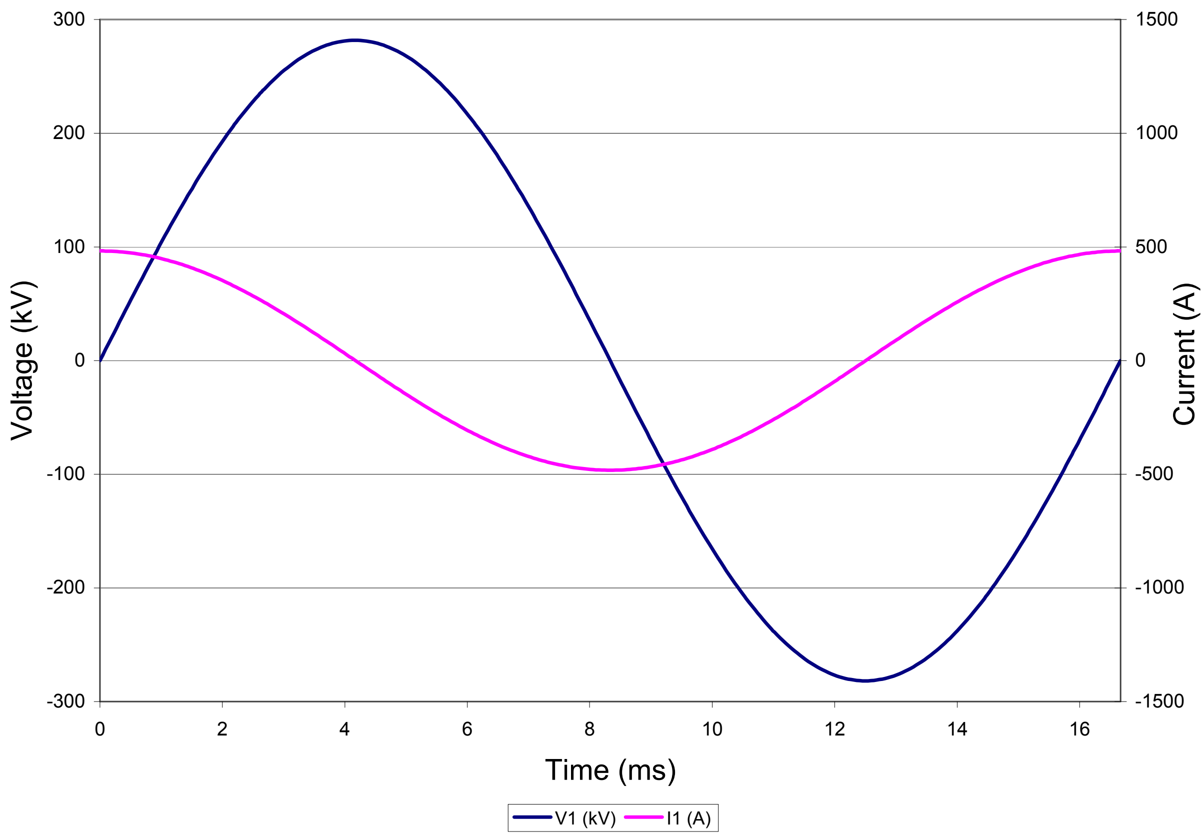

Figure 4-10
Waveshapes of Source Voltage and Current—Open Load Circuit

Table 4-2
Summary of Simulation Results—Open Load Circuit

Measured			Calculated	Estimated	Calculated
V_1 (kV rms)	I_1 (A rms)	Φ_1 (º)	P_1 (kW)	P_{TS} (kW)	tan δ (%)
199.19	340.92	89.852	175.02	14.24	0.237

The results show that the dissipation factor can be determined by accurately measuring the voltage, current, and phase angle from the energized end of the cable circuit when the load side of the cable circuit is set open.

Case 2: Simulation With a 1.0 Power Factor Load and Maximum Allowable Real Current

The simulation was then performed for a circuit with a load of 1.0 power factor. A load (R_L) of 230 Ω is used to produce the maximum allowable real current. Figure 4-11 shows plots of source voltage (V_1) and current (I_1), and load voltage (V_2) and current (I_2) as indicated in Figure 4-6. The phase angle (Φ_1) between V_1 and I_1 is 89.85º and the phase angle (Φ_2) is 0º, resulting in a power factor of 1.0. The charging current I_{CHARGE} flowing through the cable insulation is equal to the magnitude of vector subtraction of I_1 and I_2 as shown in Equation 4-9.

$$I_{CHARGE} = \vec{I}_1 - \vec{I}_2 \qquad \text{Eq. 4-9}$$

Hence, the real power consumed by the cable due to the charging current (P_{CHARGE}) is determined by Equation 4-10.

$$P_{CHARGE} = V_1 \times I_{CHARGE} \times Cos(\Phi_{CHARGE}) \qquad \text{Eq. 4-10)}$$

where Φ_{CHARGE} is the phase angle difference between V_1 and I_{CHARGE}.

The power consumed by the total series resistance (R_{TS}) due to the charging current can be estimated by Equation 4-11, again assuming that half of the charging current is going through the series resistance.

$$P_{TS} = R_{TS} \times \left(\frac{I_{CHARGE}}{2}\right)^2 \qquad \text{Eq. 4-11}$$

Tan δ is then estimated by Equation 4-12 as derived from Equation 4-1.

$$Tan(\delta) = \frac{P_{CHARGE} - P_{TS}}{V_1 \times I_{CHARGE}} \qquad \text{Eq. 4-12}$$

Table 4-3 summarizes the simulation results.

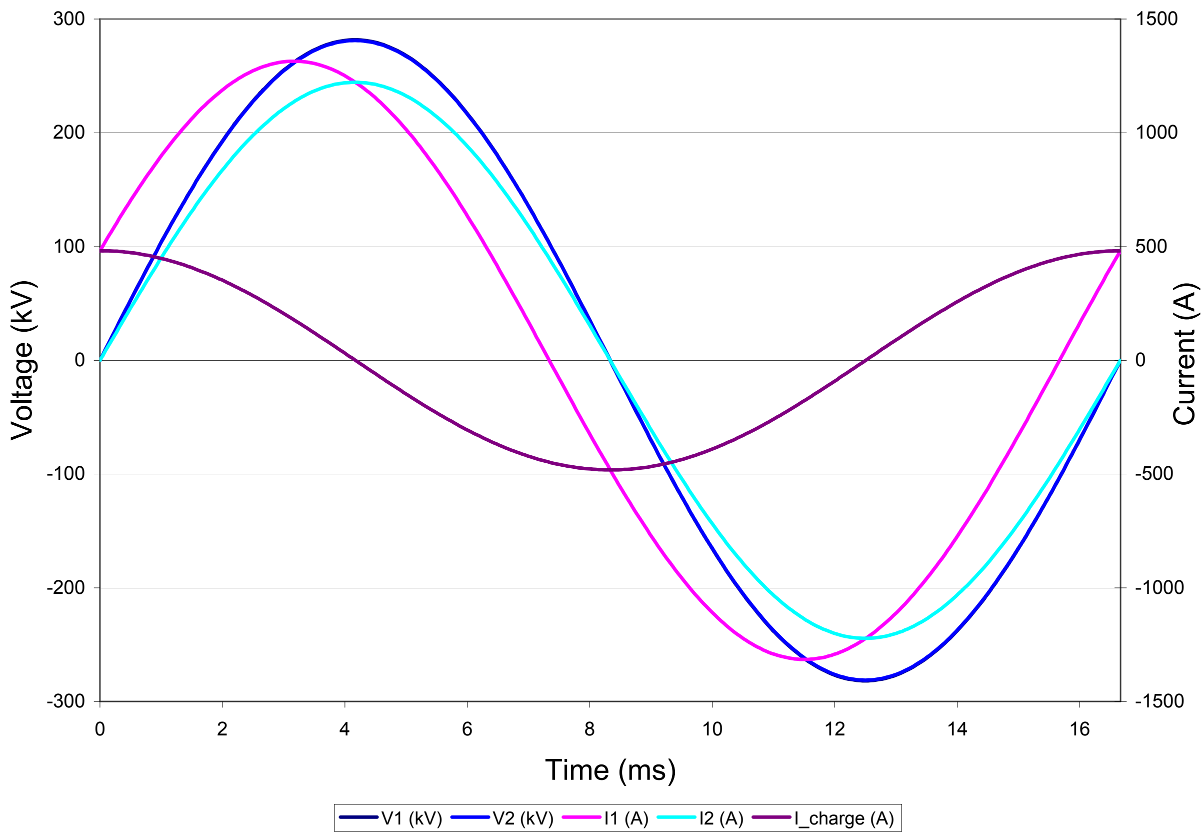

Figure 4-11
Waveshapes of Source and Load Voltage and Current—1.0 Power Factor Load, Maximum Allowable Real Current

Table 4-3
Summary of Simulation Results—1.0 Power Factor Load, Maximum Allowable Real Current

Measured			**Estimated**				**Calculated**
V_1 (kV rms)	I_1 (A rms)	Φ_1 (°)					
199.19	929.56	21.47					
V_2 (kV rms)	I_2 (A rms)	Φ_2 (°)	I_{CHARGE} (A rms)	Φ_{CHARGE} (°)	P_{CHARGE} (kW)	P_{TS} (kW)	tan δ (%)
198.76	864.16	0.00	340.55	89.855	172.28	14.21	0.233

The results indicated that if a load of unity power factor is connected to the load side of the cable, the dissipation factor can be determined by accurately measuring the voltage, current, and phase angle from the source side and at least the current from the load side, with synchronized measurements between the source side and load side to determine the charging current and phase angle relative to the source voltage. The load voltage may not be required to determine the dissipation factor for a radial system. For a looped system, it is then necessary to measure the voltage, current, and phase angle from both ends of the cable.

Case 3: Simulation With a 0.9 Power Factor Load

The simulation was then performed for a circuit with a load of 0.9 power factor. A load (R_L) of 230 Ω and 0.30 H in series is used. Figure 4-12 shows plots of source voltage (V_1) and current (I_1), and load voltage (V_2) and current (I_2) as indicated in Figure 4-6. The phase angle (Φ_1) between V_1 and I_1 is 0.1° and the phase angle (Φ_2) is 26.2°, resulting in a power factor of 0.9. The equations for determining the charging current, the real power consumed by the cable due to the charging current, the power consumed by the total series resistance due to the charging current, and tan δ are the same as described for Case 2. Table 4-4 summarizes the simulation results.

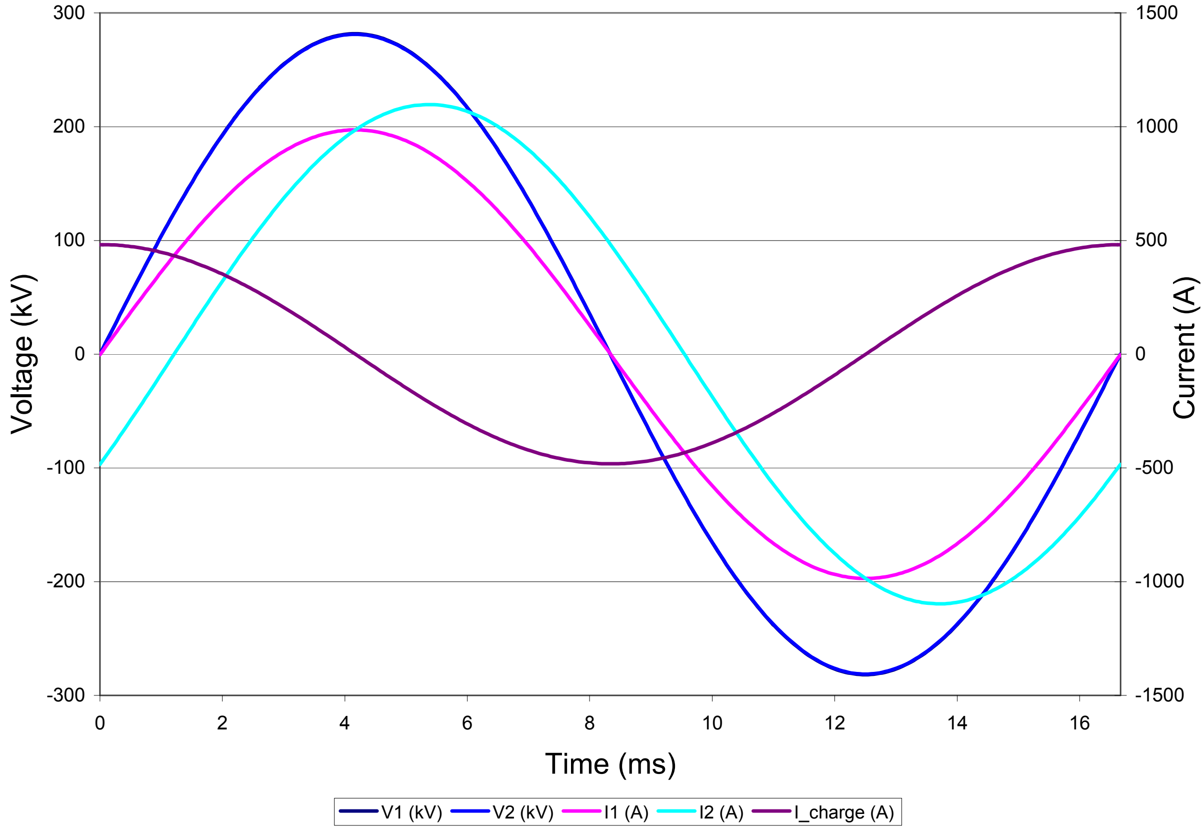

Figure 4-12
Waveshapes of Source and Load Voltage and Current—0.9 Power Factor Load

Table 4-4
Summary of Simulation Results—0.9 Power Factor Load

Measured			**Estimated**				**Calculated**
V_1 (kV rms)	I_1 (A rms)	Φ_1 (°)					
199.19	697.06	0.1					
V_2 (kV rms)	I_2 (A rms)	Φ_2 (°)	I_{CHARGE} (A rms)	Φ_{CHARGE} (°)	P_{CHARGE} (kW)	P_{TS} (kW)	tan δ (%)
198.84	775.84	26.2	340.62	89.861	164.64	14.21	0.222

The results indicated that if a load of 0.9 power factor is connected to the load side of the cable, the observations in Case 2 are still valid.

Case 4: Simulation With a 0.9 Power Factor Load and 25% Higher Dissipation Factor

The simulation was then performed for a circuit with a load of 0.9 power factor as for Case 3. The resistance of the cable insulation was reduced by 20% to simulate an increase in cable dissipation factor. Figure 4-13 shows plots of the source voltage (V_1) and current (I_1), and load voltage (V_2) and current (I_2) as indicated in Figure 4-6. The phase angle (Φ_1) between V_1 and I_1 is 0.1° and the phase angle (Φ_2) is 26.2°, resulting in a power factor of 0.9. The equations for determining the charging current, the real power consumed by the cable due to the charging current, the power consumed by the total series resistance due to the charging current, and tan δ are the same as those for Case 2. Table 4-5 summarizes the simulation results.

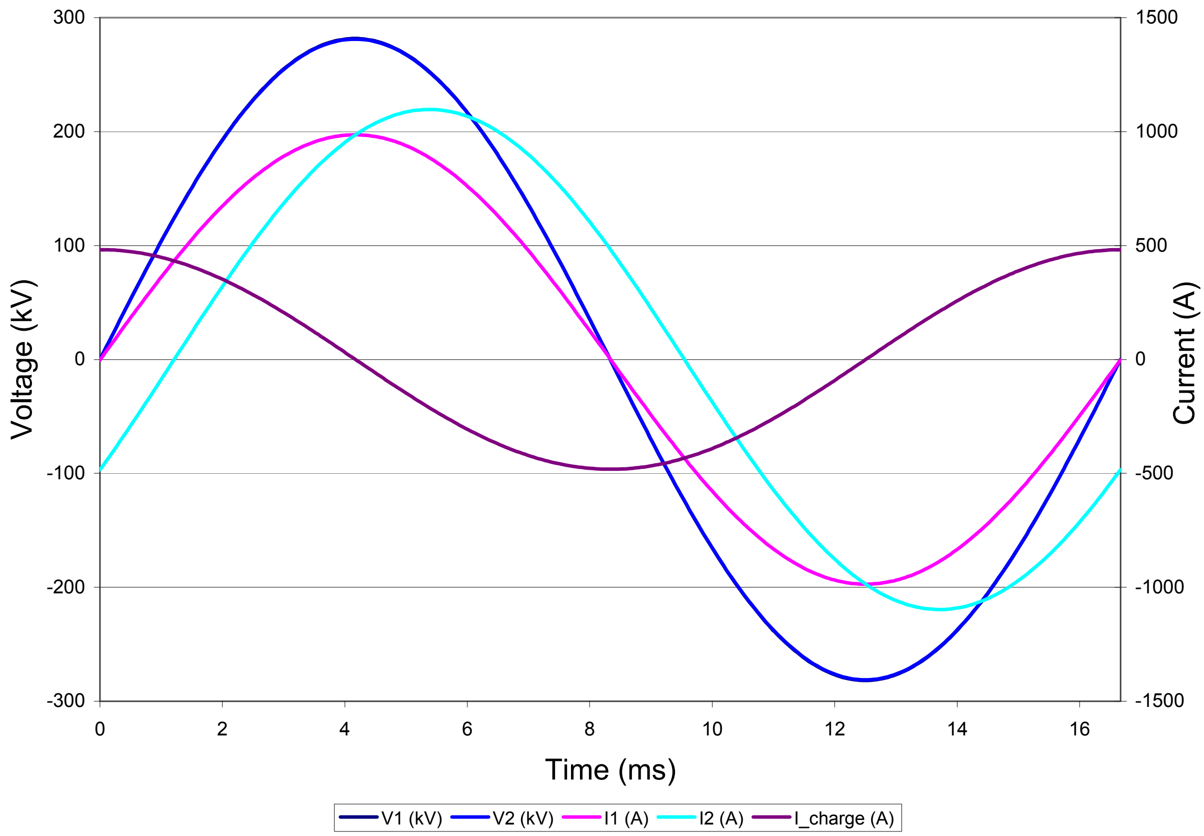

Figure 4-13
Waveshapes of Source and Load Voltages and Current—0.9 Power Factor Load, 25% Higher Dissipation Factor

Table 4-5
Summary of Simulation Results—0.9 Power Factor Load, 25% Higher Dissipation Factor

Measured			Estimated				Calculated
V_1 (kV rms)	I_1 (A rms)	Φ_1 (º)					
199.19	697.26	0.1					
V_2 (kV rms)	I_2 (A rms)	Φ_2 (º)	I_{CHARGE} (A rms)	Φ_{CHARGE} (º)	P_{CHARGE} (kW)	P_{TS} (kW)	tan δ (%)
198.84	775.84	26.2	340.62	89.829	203.01	14.21	0.278

The results indicated that if a load of 0.9 power factor is connected to the load side of the cable, the dissipation factor can be determined if it is increased by 25%, and the observations in Cases 2 and 3 are still valid.

4.6.4 Discussions of Simulation Results

Simulation Result Accuracy

Table 4-6 summarizes the results of the four simulation cases. Compared with the nominal dissipation factors for each case, the calculated values are all within 5%, which is considered acceptable for field measurements. The difference is most likely caused by the way in which the phase angles are determined. In these simulations, the phase angles were determined by reading the maximum values from the voltage and current magnitude and the time of each value. Hence, the time resolution on the display of the plots alternatively determines the accuracy of the readings. In these simulations, the time resolutions were all set at 100 MS/s.

Table 4-6
Summary of Results of the Four Simulation Cases

Case	Description	Nominal Dissipation Factor (%)	Simulated Dissipation Factor (%)	Difference (%)	Φ_{CHARGE} (º)
1	Open load	0.23	0.237	2.9	89.852
2	Load with 1.0 power factor	0.23	0.233	1.3	89.855
3	Load with 0.9 power factor	0.23	0.222	-3.6	89.861
4	Load with 0.9 power factor and 25% dissipation factor increase	0.288	0.278	-3.4	89.829

Synchronized Measurements from Both Terminals of a Cable Circuit

The alternative on-line approach to monitoring the dissipation factor requires synchronized measurements of voltages, currents, and phase angles from both ends of the cable circuit. A real-time data processing system is also required to determine the charging current and phase angle, based on the measurements. The technologies for the synchronized measurements and communications have advanced considerably in recent years. High-speed data acquisition and data processing systems are also readily available.

Measurement Accuracy

The simulation results show that the accuracy of the calculated dissipation factor values is greatly affected by the accuracy of the determination of the phase angle between the source voltage and the charging current, either directly measured (for example, open load circuit) or derived from the source current and the load current. However, the effect of the magnitudes of the voltages and currents is not as significant as the phase angles. Table 4-6 lists the phase angles (Φ_{CHARGE}) for each case. While all other conditions are the same in Cases 3 and 4, the phase angle difference is only about 0.032º. Therefore, for a reliable measuring system, the level of accuracy for the phase angle (Φ_{CHARGE}) needs to be in a range of 0.001º and 0.005º (or 0.02 and 0.1 milliradian) based on the simulation results.

Instrumentation for the measurements can include current transformers, voltage transformers, and devices to determine phase angles. Traditional instrument transformers can have errors from 0.1º to as high as 0.5º and may not be used for the application. Instruments for power system protection, such as various types of digital relays (for example, synchrophasors), may be applied for phase angle estimation. A data acquisition system with a sampling rate of 100 MS/s or higher may serve this purpose. Time synchronization may also introduce some errors, which are usually in the range of 1 μs peak or 0.02º. The accuracy of the devices needs to be investigated to understand and confirm their applicability.

Other Factors

As indicated before, dissipation factor monitoring seeks to determine the dielectric losses of the cable at the rated system voltage. These losses can be estimated by the known dissipation factor as determined by, for example, the factory tests on the cable reels. After the cable is put into operation, the dielectric losses are affected by many other factors. A typical one is the temperature of the cable insulation (see Section 4-2). During the monitoring, the temperature effect can be included by monitoring the pipe temperature, and the measured values can then be corrected as necessary. A dynamic rating system or a simplified version of the dynamic rating system can be used to estimate cable temperatures and losses with reasonable accuracy.

Similarly, the conductor resistance is a function of conductor temperature, and the resistance can be corrected by estimating the temperature. Pipe losses can be estimated by a linear resistance, as shown in the simulation cases. However, the effect of these losses is a function of many variables surrounding the pipe (such as adjacent circuits, soils, pipe coatings, or types of steel).

Daily or long-term load cycling affects the temperature of the cable and therefore the dielectric losses of the cable. It introduces another factor that affects the monitoring of the dissipation factor.

Data Processing and Control

With all the variables that may affect the dielectric loss monitoring, data processing and ultimately control of the system become challenging tasks. It may help to develop an artificial intelligence system to understand the behavior of the monitoring system and its reaction to various factors. The demanding requirements for the instrumentation of the system, as discussed before, may be reduced by applying advanced data processing algorithms. Trend changes among dissipation factor measurements for each phase can be used for the monitoring.

The equivalent circuit used for the simulations is a first degree of estimation of the cable. The cable is actually a distributed circuit. A higher level of equivalent circuit is easy to apply, and the circuits can be used to develop a high degree of estimation for conductor losses, pipe losses, and conductor inductance effect. The charging current can then be better estimated from the equivalent circuits.

Alternative Method of Determining Tan δ From Measurements

An alternative method of determining the dissipation factor from the measured values is to use the real power as determined by the voltage, the current, and their phase angle at each end of the cable circuit. The advantage of this method is that it can be more easily applied to the looped circuit than can the method demonstrated in the simulation cases in which the direction of the power flow may already be known.

The real power flowing into the cable circuit is calculated by Equation 4-13 (the same as Equation 4-6).

$$P_1 = V_1 \times I_1 \times Cos(\Phi_1) \qquad \text{Eq. 4-13}$$

The real power flowing out from the cable circuit is calculated by Equation 4-14.

$$P_2 = V_2 \times I_2 \times Cos(\Phi_2) \qquad \text{Eq. 4-14}$$

Hence, the real power consumed by the cable due to both the load current and the charging current is determined by Equation 4-15.

$$P_{CHARGE} = P_1 - P_2 \qquad \text{Eq. 4-15}$$

The charging current I_{CHARGE} flowing through the cable insulation is equal to the magnitude of vector subtraction of I_1 and I_2 as shown in Equation 4-16 (the same as Equation 4-9).

$$I_{CHARGE} = \vec{I}_1 - \vec{I}_2 \qquad \text{Eq. 4-16}$$

The power consumed by the total series resistance (R_{TS}) due to the charging current and load current can be estimated by Equation 4-17, again assuming that half of the charging current is going through the serious resistance.

$$P_{TS} = R_{TS} \times [(\frac{I_{CHARGE}}{2})^2 + (I_2)^2] \qquad \text{Eq. 4-17}$$

Tan δ is then estimated by Equation 4-18 (the same as Equation 4-12).

$$Tan(\delta) = \frac{P_{CHARGE} - P_{TS}}{V_1 \times I_{CHARGE}} \qquad \text{Eq. 4-18}$$

Since this method calls for the subtraction of two “big” numbers (Equation 4-15), additional error may be introduced. This method also requires accurate measurements of voltage, current, and phase angle from each end of the cable, while the method used in the simulation cases does not use the voltage measurement on the load side of the circuit.

5 CONCLUSIONS AND FUTURE WORK

Most failure mechanisms and failure modes of laminar dielectric cable systems are well understood, although EPRI is investigating the thermomechanical behavior of cables in pipes. Many diagnostic and assessment techniques are widely applied to inspect the condition of laminar dielectric cable systems. The techniques can be used off-line or on-line. Recent research and development have focused heavily on on-line monitoring. This report investigated a technique for on-line circuit dissipation factor measurements.

The new concept of the insulation loss monitoring system uses measurements from both terminals of a cable circuit, such as voltages, currents, and phase angles, to determine the dielectric losses of the cable insulation. With present synchronization and communication technologies, measurements can be recorded at an exact moment from both cable terminals. The data can then be transmitted to a central data processing unit to determine the dissipation factor of the cable circuit.

The on-line circuit dissipation factor system can include voltage, current, and phase angle transducers and a signal conditioning and data acquisition unit at each end of the cable circuit. Temperature measurements obtained through sensors for the pipe surface, ambient air, or soil can be used to correct dissipation factor measurement. Measurement synchronization and data communications are critical to this system and need to be investigated further. Data can be processed and displayed to set up alarms and warnings if one phase dissipation factor begins to deviate significantly from the other two.

Investigation of these and other condition assessment techniques will continue in the coming years. In addition to the continuing efforts to test and demonstrate the concept of on-line dissipation factor monitoring, this effort will explore other ideas. One example is on-line monitoring of fluid moisture, resistivity, and the fluid dissipation factor. An EPRI Technology Innovation project is in progress to investigate techniques for on-line dissolved gas analysis.

A series of guides will be developed to assist utility personnel in applying existing technologies to assess the condition of laminar dielectric cable systems. The guides will cover the following topics.

- Measurement of field laminar dielectric cable dissipation factor (2010)
- Dissolved gas analysis and paper insulation testing of laminar dielectric cable systems (2011)
- Radiographic inspection of splices, terminations, trifurcators, and laminar dielectric cables
- Inspection of pressurizing systems
- Partial discharge testing of laminar dielectric cable systems

6
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A
GUIDE FOR FIELD LAMINAR DIELECTRIC CABLE DISSIPATION FACTOR MEASUREMENTS

A.1 Introduction

Principles of dissipation factor measurements are discussed in Section 4 of this report. Field cable dissipation factor measurement instrumentation was developed by EPRI [EPRI 1993]. This guide captures the latest experiences in circuit dissipation factor tests using the EPRI-developed techniques and discusses their limitations.

A.2 General Requirements

During measurement of the cable dissipation factor, the cable circuit must be deenergized and reenergized three times, once for each of the three phases. The cable circuit must be energized from one end and kept open at the other end during the measurements, and any auxiliary equipment at the open end of the circuit that draws an appreciable amount of power must be disconnected during the measurements. For example, if there are shunt compensation reactors in the substation at the open end of the cable circuit, they must be disconnected (usually by means of a circuit switcher). The best measurement results are obtained if any surge arrestors at the cable open end are also disconnected; however, this is not absolutely necessary if the cable circuit is three or more miles long. It is necessary only that the cable charging current flow through the current shunt between the high-voltage bus and the cable termination at the energizing end. The dissipation factor instrument currently has a maximum charging-current limitation of 300 A.

Dissipation factor measurements can be made with the cable at any temperature; however, it is desirable to have as accurate a temperature as possible for the majority of the cable system at the time of measurement. This is because of the dissipation factor of the cable varies with temperature. It is impossible to determine if a change in the dissipation factor is due to a change in the cable insulation or a change in the temperature of the insulation if measurements are made at significantly different temperatures. It is best to make the dissipation factor measurements on a cable after it has been deenergized for at least 24 hours, as would be the case when the cable circuit has been out for repairs or maintenance. This is because a transmission cable, especially a pipe-type cable, takes a long time to cool down to the ambient earth temperature. After the cable has cooled down, its temperature should be fairly constant regardless of the air temperature. The amount of time that the cable has been deenergized before performing the measurements should be recorded along with the dissipation factor reading. If the cable has been carrying load within the past 24 hours, an estimate of the amount of load that the cable was carrying is also helpful for subsequent comparisons of measurements.

The charging-current transmitter of the dissipation factor measurement system is powered by standard D cell batteries. New batteries will provide power to the device for approximately three and a half hours. A radio-frequency remote control facilitates turning the charging current on and off to conserve battery life between measurements.

The insulation dissipation factor is determined by very accurately measuring the phase displacement between the charging current in a “loss-free” standard capacitor and the cable charging current.

A.3 Electrical Connections

Electrical connections must be made to the cable circuit and power system to make the measurements. A low-inductance shunt (several mΩ) must be connected between the high-voltage bus and the cable termination. Flexible copper straps are provided for this purpose. The second electrical connection must be established between a special high-voltage capacitor (standard capacitor) and the same phase of the station bus as the phase that the low-inductance shunt is connected to. A fiber-optic cable is then connected from the charging-current transmitter to an instrument at ground level.

If there is a flexible copper strap between the high-voltage bus and the aerial lug on the top of the termination (as is usually the case), then the connection of the low-inductance shunt requires no special hardware. If the termination supports one end of the high-voltage bus, then a minimal amount of special hardware must be provided to make this connection.

A.4 High-Voltage Equipment Ratings

The high-voltage standard capacitor for making the dissipation factor measurements has a continuous voltage rating of 200 kV (line to ground) and was tested at 220 kV ac. The basic insulation level (BIL) rating of the standard capacitor is 600 kV. Although the ac voltage rating of the standard capacitor is 50% higher than the line-to-ground operating voltage of a 230-kV system, the BIL rating is lower than that of a 230-kV system (1050-kV full-level BIL). It is believed that this reduced BIL of the standard capacitor presents no problems to the normal operation of the power system if the measurements are made in dry weather. Measurements have been made on six 230-kV transmission cable systems with no problems. However, the voltage rating of the equipment is not sufficient to perform dissipation factor measurements on 345-kV cable systems unless a resonant test set is used to energize the cable circuit without switching transient overvoltages.

The high-voltage standard capacitor is filled with SF6 gas at a pressure of 90 psig. Dissipation factor measurements should not be made when ambient temperatures are –5°C or lower. This is to avoid condensation of the compressed SF6 gas.

A.5 Duration to Perform the Measurements

It typically takes about 4 to 8 hours to make the three measurements on a given three-phase cable circuit. A major part of this time is spent getting clearances to take the circuit out of service and connecting and disconnecting safety grounds; though this time varies from one utility to another. For example, measurements were made on two 115-kV submarine cable circuits in 5.5 hours, with close coordination with utility personnel.

A.6 Planning

The most important coordination items are a detailed description of the mechanical connections between the high-voltage bus and the top of the termination to make sure that hardware is on hand before the measurements are made. This can be accomplished in the field; however, a few photos and some advanced planning are recommended. It is also important to determine an appropriate location for the high-voltage standard capacitor at ground level while it is connected to the high-voltage bus.

Provisions should also be made for some type of safety barrier in the vicinity of the high-voltage standard capacitor. (As a minimum, warning tapes should cordon off the area around the capacitor.)

A good estimate of the total cable charging current for the circuit must be determined during preparations for the measurements. If an accurate estimate of the charging current is not available from the utility, a drawing of the cable and an accurate length of the circuit must be obtained from the utility.

Current substation drawings or photos of the area around the cable terminations are needed to determine if there are sufficient electrical clearances to place the high-voltage standard capacitor at ground level during the measurements. A clear open space with at least the height of the cable terminations on all sides must be available to perform the measurements.

A.7 Transportation of InstrumentationThe equipment is shipped in advance via common carrier (four crates with a total weight of 380 lb [172 kg]).

A.8 Dissipation Factor Measurement Procedure

The following steps are required to perform dissipation factor measurements on a three-phase cable system. The times indicated for the various tasks are typical times based on measurements that have been performed.

1. Clearance is obtained for switching the circuit out of service.
2. The high-voltage bus that feeds the cable circuit is deenergized, and adequate safety grounds are connected by utility personnel. (30 to 60 minutes)
3. The charging-current transmitter is connected between the high-voltage bus and one cable termination. This is accomplished by unbolting the flexible leads connected to the aerial lug at the top of the cable termination and connecting the flexible lead to the insulated bushing on the charging-current signal transmitter. The metal flange (NEMA two-hole pad) of the current shunt is then connected to the cable aerial lug with a flexible copper strap provided with the charging-current signal transmitter. Alternatively, the NEMA two-hole pad of the charging-current transmitter can be bolted directly to a NEMA four-hole pad at the top of the cable termination, as shown in Figure A-1. (30 minutes)

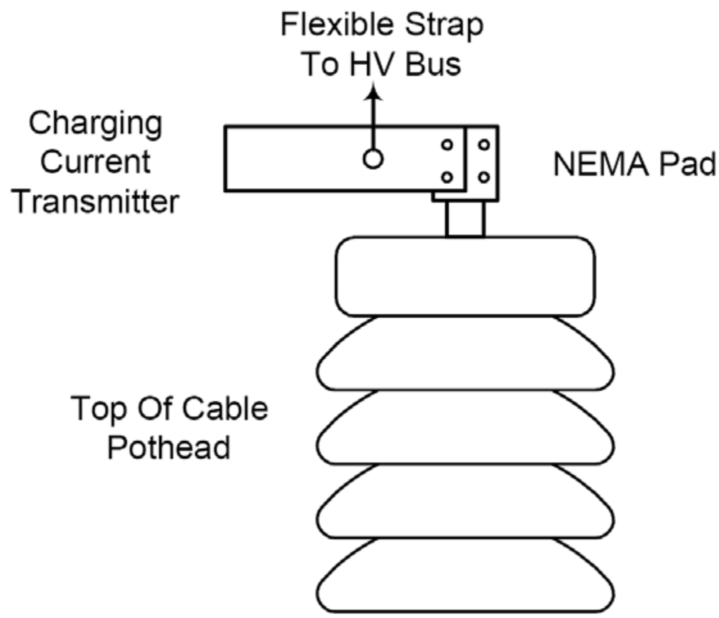

Figure A-1
Connection Detail at Top of Termination (Pothead)

4. The fiber-optic cable is connected between the charging-current transmitter and the dissipation factor bridge at ground level. The fiber-optic cable is run along and taped to the high-voltage bus so that it will clear the termination stand when it is lowered to ground level. The transmitter is subsequently turned on with a remote-control transmitter (similar to a garage door opener).
5. The standard capacitor is set up beneath a section of the bus to which the cable termination was connected in Step 2, and the base is connected to the closest station ground (see Figure A-2). The standard capacitor is located directly below the bus, if possible, and as far from grounded structures as possible.

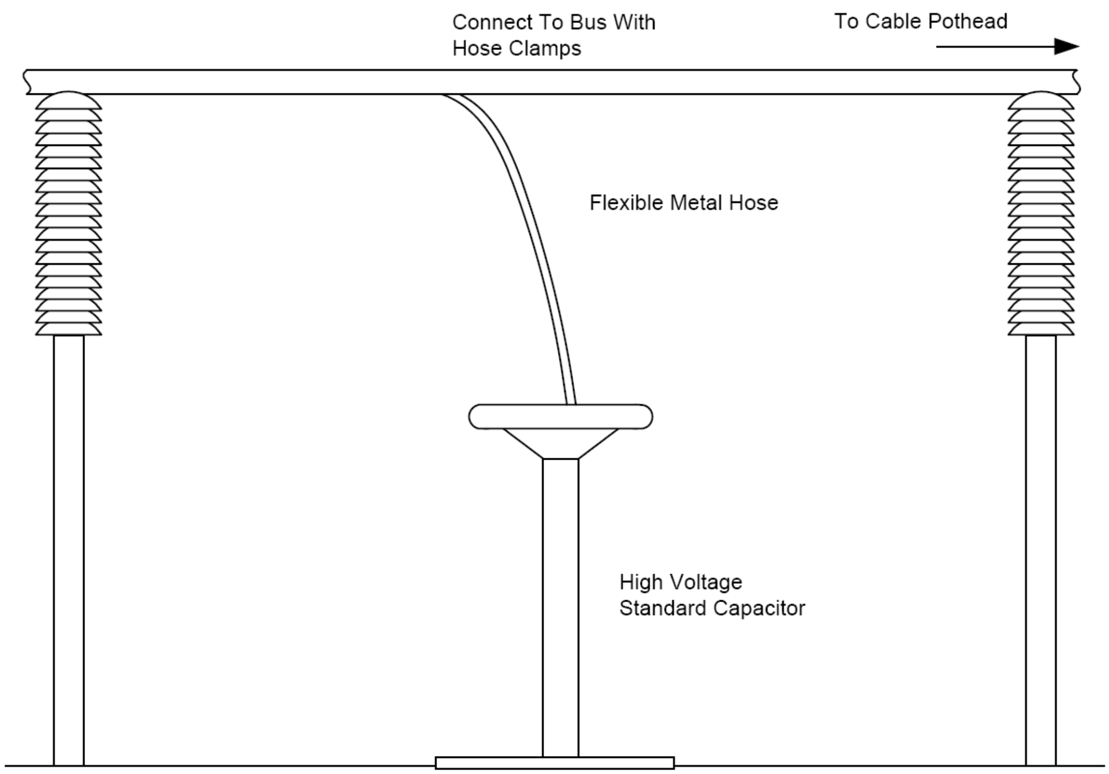

Figure A-2
Standard Capacitor Connection to High-Voltage Bus

6. A barrier warning tape is placed around the standard capacitor to warn of the presence of high voltage since the top of the capacitor will be energized at line potential. (30 minutes)
7. The dissipation factor bridge and charging-current receiver is located as far from the standard capacitor as permitted by the coaxial cable that runs from the bridge to the standard capacitor. An extension cord is required to power the bridge and fiber-optic receiver from 110-V ac service. A wire must be connected from the bridge ground to the closest station ground.
8. The coaxial cable from the standard capacitor is plugged into the “CN” connection on the back of the bridge. The optical fiber cable is connected to the charging-current signal receiver, and a short section of coaxial cable must also be connected from the charging-current transmitter to the “CX” connector on the back of the bridge.
9. The safety grounds are removed from the high-voltage bus and the cable circuit energized after clearance is obtained from substation operation personnel. (typically 30 minutes)
10. The dissipation factor bridge is balanced and the reading recorded. (5 minutes)
11. The circuit is deenergized and the safety grounds reconnected. (30 minutes)
12. The dissipation factor equipment is disconnected from the high-voltage bus and the cable termination.
13. Steps 2 to 8 are repeated if measurements are to be made on another phase of the cable circuit.
14. The safety grounds are disconnected and the cable reenergized. (30 minutes)

A.9 Interpretation of Measurement Results

If the measurements indicate that the dissipation factor of the cable exceeds the values in Tables A-1 and A-2, there may be some form of deterioration of the insulation or contamination of the dielectric fluid. It may also be necessary to determine the value of the dissipation factor when it was measured for the manufacturing lengths during the routine factory tests since the allowable dissipation factor was higher in past AEIC specifications. A dissipation factor over 1% indicates that either something is wrong with the cable or the measurements. A comparison of the measured values for the three phases of the same circuit may help in the interpretation of the measurement results.

Table A-1
Maximum Dissipation Factor (%) for High-Pressure Pipe-Type Cables

Cable Temperature (°C)	Paper Insulation			Laminated Paper Polypropylene Insulation
	69 to 161 kV	230 to 500 kV (A-Standard Design)	230 to 500 kV (B-Improved Impulse Design)	69 to 765 kV
20 to 40	0.35	0.25	0.28	0.13
80	0.30	0.23	0.25	0.10
90	0.35	0.25	0.28	0.11

Source: AEIC 1997

Table A-2
Maximum Dissipation Factor (%) for Self-Contained Fluid-Filled Cables

Cable Temperature (°C)	69 to 161 kV	230 kV	345 to 500 kV
20 to 40	0.35	0.30	0.25
80	0.30	0.25	0.23
90	0.35	0.28	0.25

Source: AEIC 1993

If a cable dissipation factor value is less than those shown in Tables A-1 and A-2, the results of the measurements are subject to interpretation since the dissipation factor varies with the temperature of the cable. Evaluation of the test results is straight forward if a history of the dissipation factor at similar temperatures is available. Otherwise, it is difficult to determine if the variations from the values in Tables A-1 and A-2 are the result of changes in the insulation or environmental factors. If the dissipation factor shows an increase of more than 20% over previous measurements at approximately the same cable temperature, further diagnostic measurements such as detailed dielectric fluid tests may be in order. If the dissipation factor of one of the three phases is more than 30% higher than that of the other phases in the same circuit, further diagnostic tests may be required.

A low dissipation factor means that the bulk of the cable is in good condition. It does not preclude the existence of a localized problem. For example, the dissipation factor of a cable circuit could be well within an acceptable range if a problem exists in a single joint—unless a joint is on the verge of failure.

A.10 Case Studies

A.10.1 Polk-Midtown-Garrott 138-kV HPFF Cable Circuit, CenterPoint Energy

Dissipation factor measurements were performed to assess the condition of a 36-year-old HPFF 138-kV cable circuit [EPRI 2002]. The measurements were performed at the Midtown Substation (Figure A-3). The 138-kV HPFF cables (Figure A-4) were manufactured by the Okonite Company in 1966. Figures A-5 and A-6 show linemen connecting the dissipation factor equipment to the high-voltage bus and cable terminations.

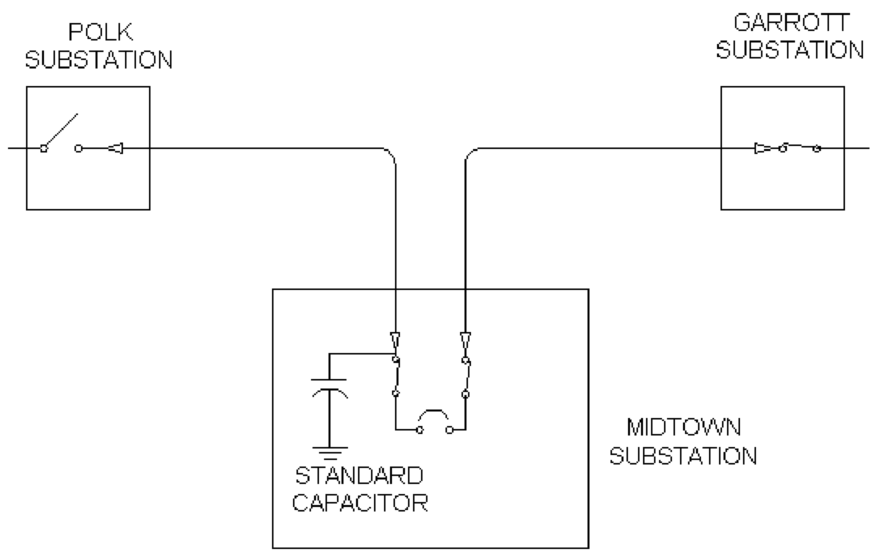

Figure A-3
Schematic of Polk-Midtown-Garrott Underground Transmission Line

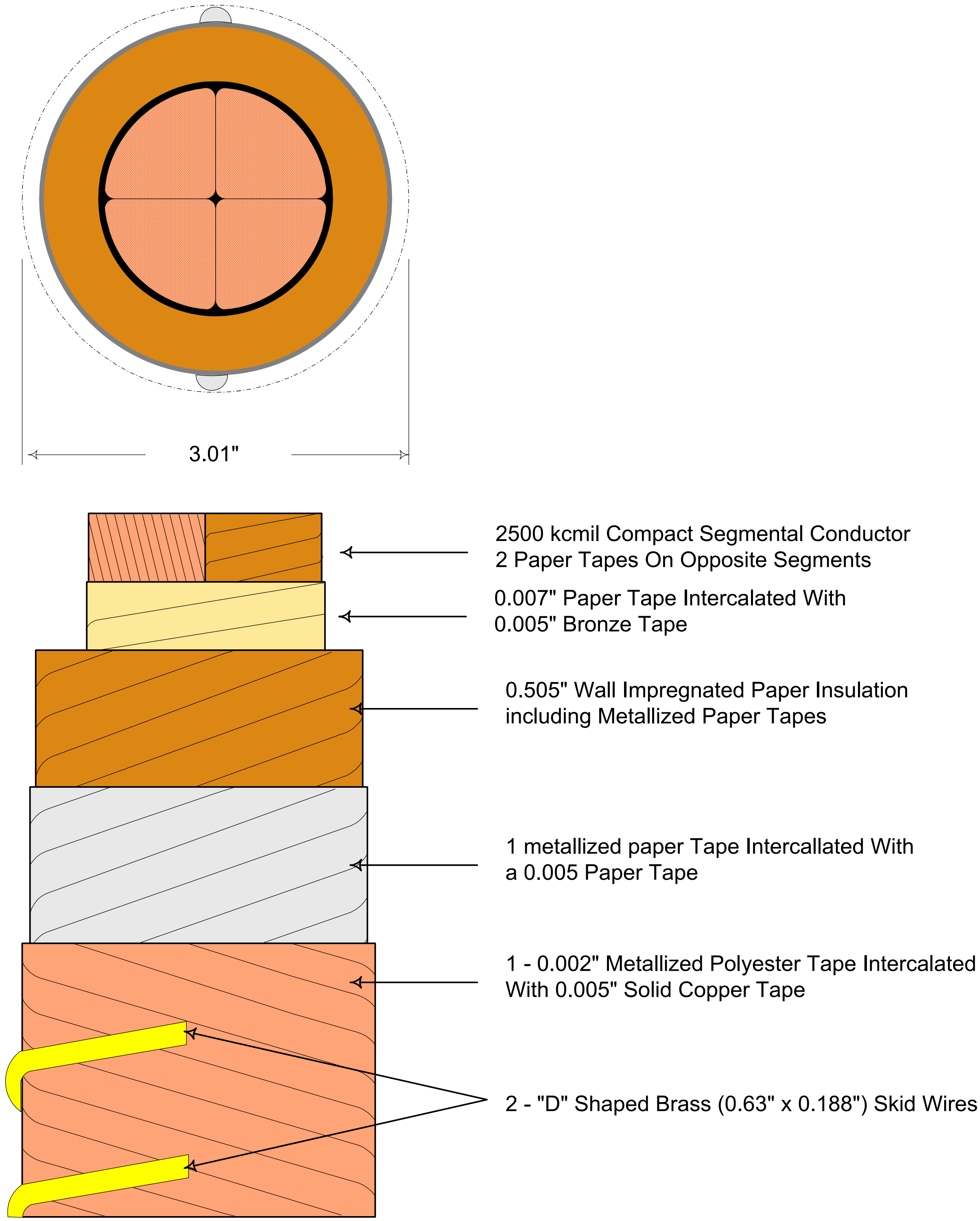

Figure A-4
Okonite 2500-kcmil, 138-kV HPFF Cable

Figure A-5
Standard Capacitor Connection in Midtown Substation

Figure A-6
Low-Inductance Shunt Connection

Values of the dissipation factor read from the instrumentation must be corrected for errors associated with the measurement circuit or the length of the cables. The corrected values of the cable dissipation factor measurements for the two cable circuits are shown in Table A-3.

Table A-3
Cable Dissipation Factor Measurements

Circuit	Phase	Dissipation Factor (%)
Polk-Midtown	A	0.218
Polk-Midtown	B	0.228
Polk-Midtown	C	0.224
Midtown-Garrott	A	0.238
Midtown-Garrott	B	0.248
Midtown-Garrott	C	0.237
Average		0.232

The correction factor for the cable series impedances adjusts the measured dissipation factor (for example, the value indicated by the bridge) for the joule losses in the cable conductor caused by the cable charging current and for the voltage drop caused by the series inductance.

$$DF_{corrected} = DF_{measured}\left(1 - \frac{bxL^2}{2}\right) - \frac{brL^2}{2}$$

Where: x = Cable series inductive reactance, Ω per ft
b = Cable shunt susceptance, Mho per ft
r = Cable ac resistance, Ω per ft
L = Cable length, ft

The cable parameters for calculating the series impedance correction factors are shown in Table A-4. These cable circuit parameters were calculated from the physical dimensions of the cable (Figure A-4).

Table A-4
Cable System Electrical Parameters

Parameter	Midtown-Garrott	Midtown-Polk	Units
Series inductive reactance (x)	43.6	43.6	μ Ω /ft
Capacitive susceptance (b)	$4.6\ 10^{-8}$	$4.6\ 10^{-8}$	Mho/ft
AC resistance (r)	6.58	6.58	μ Ω /ft
Circuit length, Midtown-Garrott (L)	1.06 (5,600)	1.30 (6,860)	Miles (ft)

The maximum difference among the dissipation factor values measured for the six cables was approximately 14%. Previous test experience and factory test reports for HPFF cables manufactured during this period indicate that the variations are not significant. Maximum variations of up to 15% have been reported for the reels of cable for a given order.
The AEIC specification for HPFF transmission cable at the time that the Polk-Midtown-Garrott cables were manufactured lists a maximum dissipation factor of 0.6% for cables with a rated

voltage of 15 kV to 161 kV at a temperature ranging from 20 to 60°C. The exact temperature of the Polk-Midtown and Midtown-Garrott cables could not be determined at the time of measurement; however, it was estimated that the cable temperature was between 30 and 40°C. The dissipation factors of the Polk-Midtown and Midtown-Garrott cables were well below the AEIC dissipation factor specification for new cables (at the time that they were manufactured). This may be due to the fact that the Polk-Midtown-Garrott cables were manufactured when there was a general trend of improving dissipation factors for HPFF cables. It is also known that the dissipation factors of the Okonite cables were generally lower than those manufactured by the other HPFF cable manufacturers in 1966 (Phelps Dodge, Anaconda, and General Cable).

The comparisons between the cables and the fact that the absolute value of the cable dissipation factors was well below the maximum value allowed by AEIC CS 2 at the time that they were manufactured indicate that the high-voltage insulation of the tested cables was in good condition.

A.10.2 PSE&G 230-kV and 138-kV HPFF Cable Circuits, Public Service Electric and Gas Company

Insulation dissipation factor measurements were performed on four HPFF cable circuits to assess the condition of the 22- to 45-year-old systems [EPRI 2004]. Figures A-7 and A-8 show the dissipation factor equipment at the Fairlawn Switching Station and the North Avenue Substation, respectively, of Public Service Electric and Gas Company (PSE&G).

Figure A-7
Dissipation Factor Measurements at the PSE&G Fairlawn Switching Station

Figure A-8
Dissipation Factor Measurements at the PSE&G North Avenue Substation

The corrected values of the cable dissipation factor measurements for the four HPFF cable circuits are shown in Tables A-5 to A-8.

Table A-5
Waldwick-Fairlawn (O-2267) 230-kV HPFF Dissipation Factor Measurements

Phase	Dissipation Factor (%)
Phase A	0.262
Phase B	0.284
Phase C	0.264

Table A-6
Bayway-Doremus (Q-1369) 138-kV HPFF Dissipation Factor Measurements

Phase	Dissipation Factor (%)
Phase A	0.370
Phase B	0.330
Phase C	0.354

Table A-7
Bayway–North Avenue (T-1346) 138-kV HPFF Dissipation Factor Measurements

Phase	Dissipation Factor (%)
Phase A	0.244
Phase B	0.236
Phase C	0.242

Table A-8
North Avenue–Passaic Valley Sewer Commission (E-1331) 138-kV HPFF Dissipation Factor Measurements

Phase	Dissipation Factor (%)
Phase A	0.236
Phase B	0.228
Phase C	0.234

For 230-kV HPFF cables manufactured during or after 1982, the maximum allowable dissipation factor was at 0.25% for temperatures between 20 and 40ºC. The dissipation factor for 230-kV cables manufactured before 1982 was slightly higher (0.35%). AEIC specifications for 138-kV HPFF cable systems manufactured before 1967 indicate that the maximum dissipation factor should not exceed 0.5%. However, the factory test values for 115- or 138-kV cables manufactured before 1967 indicate that 0.4% is a more typical upper limit for ambient temperature dissipation factor values. Testing experience and a review of factory test data show that the dissipation factor for different reels of cable may vary as much as 20%; however, the composite dissipation factor for installed cable systems should not deviate more than 15% because the field dissipation factor measurements yield the average value for multiple reels of cable.

Based on long-term accelerated life tests performed at the EPRI Waltz Mill Underground Transmission Test Facility and field dissipation factor measurements performed at other utilities, dissipation factor increases of up to 15% on 230-/345-kV cables with 30 or more years of in-service operation are considered normal for temperatures ranging from 20 to 40ºC. Increases in dissipation factor greater than 15% indicate that the cables have experienced thermal aging or been subjected to contamination of the insulation impregnant, or that there has been significant mechanical damage to the insulating tapes.

The maximum deviation of the field dissipation factor values and the maximum factory test value (0.25%) was 13%. The field dissipation factor measurements indicate that the maximum deviation between the lowest and highest values for the three phases of the Waldwick-Fairlawn (O-2267) was 8.4%. Based on the above dissipation factor evaluation, the high voltage insulation for the Waldwick-Fairlawn (O-2267) 230-kV HPFF cables is in good condition.

A summary of the insulation dissipation factor values for the three 138-kV HPFF cable circuits is shown in Table A-9.

Table A-9
Summary of 138-kV HPFF cable dissipation factor measurements

Dissipation Factor (%)	138-kV HPFF Circuit Numbers		
	Q-1369	T-1346	E-1331
Average value	0.351	0.241	0.232
Maximum value	0.370	0.244	0.236
Minimum value	0.330	0.236	0.228
Maximum deviation between phases	12	3.4	3.5

Based on long-term accelerated life tests and field dissipation factor measurements performed at other utilities, dissipation factor increases of up to 25% on 115/138-kV cables with 30 or more years of in-service operation are considered to be normal for temperatures ranging from 20 ºC and 40 ºC. The dissipation factor values for all of the three PSE&G 138-kV HPFF cable circuits had maximum dissipation factor values of less than 0.4% and maximum deviations in values between phases of less than 15%.

Based on the above evaluation criteria for 138-kV HPFF cable manufactured before 1967, the high voltage insulation for PSE&G 138-kV HPFF lines Q-1369, T-1346, and E-1331 are in good condition. The 12% deviation of the dissipation factor values between the phases of line Q-1369 is on the upper end of what is considered to be normal. Repeating the dissipation factor measurements at some time in the future (e.g., three to five years) would give an indication of whether this deviation is a normal occurrence or if it is due to a progressive problem with one phase.

A.10.3 Blenheim-Gilboa 345-kV HPFF Cables, New York Power Authority

Dissipation factor measurements for the Blenheim-Gilboa 345-kV HPFF transmission cables were performed using instrumentation developed by an EPRI project [EPRI 1993] and a variable frequency series resonant test set [EPRI 2005]. Figure A-9 shows the dissipation factor measurement equipment attached to one of the Blenheim-Gilboa 345-kV Cable #3 terminations. Measurements were made at 150 kV and 200 kV (line to ground) with normal pipe pressure (220 to 240 psig). The cable pipe temperature was 20 °C at the time of the measurements. Dissipation factor measurements were limited to the three phases of the Unit #3 cable because the diagnostic test was included as an indication of cable thermal aging and the four Blenheim-Gilboa 345-kV cables have been operated in similar load conditions.

Figure A-9
Blenheim–Gilboa Cable #3 dissipation factor measurements

Results of the dissipation factor measurements for the Unit #3 cable are shown in Table A.10.

Table A-10
Cable #3 dissipation factor values

Phase	Dissipation Factor (%)	
	150 kV (l-g)	200 kV (l-g)
A	0.224	0.226
B	0.216	0.214
C	0.220	0.225

Copies of the original Phelps Dodge Wire & Cable certified test reports were available at the Blenheim-Gilboa facility. A review of these test reports indicated that most reels of the cable had a dissipation factor between 0.212% and 0.238% at room temperature (25°C). A comparison between the initial dissipation factor and the dissipation factor measured at Blenheim-Gilboa indicates that there has been no significant change as a result of the past 30-years of operation.

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