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Dissolved Gas Analysis and Condition Assessment of PSE&G High-Pressure, Fluid-Filled Feeders

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PRODUCT DESCRIPTION

How underground transmission cable systems—an indispensable, intrinsic part of every utility's infrastructure—operate and age is a major concern for all utilities. This report presents information on an undertaking by Public Service Electric & Gas Company (PSE&G) to study the degrading effects of minimal operational pressures on high-pressure, fluid-filled, pipe-type cable (HPFF-PTC) insulation.

The results of this study should be used in conjunction with the Electric Power Research Institute (EPRI)/PSE&G report *Dissipation Factor Measurement of High Pressure Fluid Filled Pipe Type Cables Subjected to Prolonged Operation at Low Hydraulic Pressure* (EPRI report 1011366), which establishes guidelines for inspection of cable insulation degradation.

Results and Findings

The project was conceived to test and review data collected on four existing 138-kilovolt (138-kV) and 230-kV transmission cables that were subjected to full operational loads while operating under extremely low to no hydraulic pressures during a 2003 blackout. This report documents the results from the first of the four circuits.

Dissipation factor (DF) measurements performed after the blackout on the four affected cable circuits found no general deterioration, but the technique was unable to verify whether localized deterioration had occurred. In a collaborative venture, PSE&G and EPRI decided to apply dissolved gas analysis (DGA) to detect any localized issues at the terminations and/or manholes. As part of the project described in this report, PSE&G compared the cost and efficacy of its existing DGA method with the EPRI Disposable Oil Sampling System (EDOSS), an innovative sampling technique developed by EPRI and licensed to and administered by DTE Energy.

Challenges and Objectives

Utility management and underground technicians will benefit from the information in this report. Data collected from this project, would help PSE&G develop an insulation degradation baseline on HPFF-PTC circuits. Having similar trend data for given circuits could lower a utility's operational costs by helping the utility to avoid premature replacement of cable circuit and to identify necessary corrective action for potentially expensive impending failures.

Applications, Value, and Use

The data collected in the course of this project will not only depict the existing condition of the circuits, but will also provide an opportunity for future testing, data collection, and evaluation of damage to cables, including shortened life expectancy as the result of extraneous operational conditions. Are older transmission cables a source of significant future problems and expenses for utilities, as their 40-year life expectancy predicts? Is there a correlation between low-pressure operational conditions of HPFF-PTC systems and cable life expectancy? If so, is it linear or exponential? Can HPFF-PTC circuit failures be predicted with reasonable accuracy? The project addresses these and other important questions.

EPRI Perspective

PSE&G has approximately 220 miles (354 kilometers) and 52 circuits of HPFF-PTC systems operating at voltages of 138 kV, 230 kV, and 345 kV, with many of them now operating beyond their 40-year life expectancy. Because four of its 52 circuits were exposed to blackout conditions in 2003, PSE&G has an opportunity to evaluate, for its own benefit and that of the entire industry, the effects of abnormal operating conditions on cable insulation. EPRI—whose interest in cable insulation deterioration was behind the development of EDOSS and co-authorship of the 2004 report *Dissipation Factor Measurement of High Pressure Fluid Filled Pipe Type Cables Subjected to Prolonged Operation at Low Hydraulic Pressure* (EPRI report 1011366)—joined forces with PSE&G to examine the affected circuits. PSE&G and EPRI recognize that real savings can be derived from a systematic method of predicting the health of cable systems and detecting deterioration.

Approach

The project's goals are twofold. First, PSE&G seeks to determine what localized degradation, if any, has taken place at four cable systems in response to the 2003 blackout. For the first study, DGAs of O-2267, the circuit extending from Waldwick Switching Station to Fairlawn Switching Station, was performed in April 2006. The DGA results showed a high acetylene level, which indicates arcing, and PSG&E determined that it would be prudent to add valves and perform additional sampling on this circuit.

The second goal of this first phase of the project was to consider whether EDOSS, a new sampling method, offers substantial improvements in terms of timeliness, accuracy, or cost. Two tables and a report from DTE Energy constitute a detailed report on the results of the analysis.

Keywords

Cable insulation
Degradation
Dissipation factor (DF)
Dissolved gas analysis (DGA)
EPRI Disposable Oil Sampling System (EDOSS)
Underground transmission

ABSTRACT

How underground transmission cable systems operate and age is a major concern for all utilities. This report presents information on an undertaking by Public Service Electric & Gas Company (PSE&G) to study the degrading effects of minimal operational pressures on high-pressure, fluid-filled, pipe-type cable (HPFF-PTC) insulation. PSE&G has approximately 220 miles (354 kilometers) and 52 circuits of HPFF-PTC systems operating at voltages of 138 kV (kilovolts), 230 kV, and 345 kV, with many of them operating beyond their 40-year life expectancy. The project was conceived to test and review data collected on existing transmission cables that were subjected to full operational loads while operating under extremely low to no hydraulic pressures. Dissipation factor (DF) measurements performed after a 2003 blackout in New Jersey found no general deterioration in four circuits, but the DF technique was unable to verify whether localized deterioration had occurred. In a collaborative venture, PSE&G and the Electric Power Research Institute (EPRI) decided to apply dissolved gas analysis (DGA) to detect any localized issues at the terminations and/or manholes. As part of the project described in this report, PSE&G compared the cost and efficacy of its existing DGA method with the EPRI Disposable Oil Sampling System, an innovative sampling technique developed by EPRI and licensed to and administered by DTE Energy.

CONTENTS

1
INTRODUCTION AND BACKGROUND

Underground transmission cable systems are an indispensable and intrinsic part of every utility's infrastructure. Understanding their operational and aging mechanisms as influenced by their operating history is a major concern for all utilities, including Public Service Electric & Gas Company (PSE&G). The project that is the subject of this report studied the effects of minimal operational pressures on aging, in-service, high-pressure, fluid-filled, pipe-type cable (HPFF-PTC) insulation by analyzing the gases in the fluid. In addition, the project introduced PSE&G's underground technicians to the latest sampling technique used by DTE Energy. The results of this study should work in conjunction with the Electric Power Research Institute (EPRI)/PSE&G report *Dissipation Factor Measurement of High Pressure Fluid Filled Pipe Type Cables Subjected to Prolonged Operation at Low Hydraulic Pressure* (EPRI report 1011366) published in 2004 to establish guidelines with respect to cable insulation degradation.

PSE&G has approximately 220 miles (354 kilometers) of HPFF-PTC systems operating at voltages of 138 kilovolts (kV), 230 kV, and 345 kV in its grid. These circuits contain approximately 700 manholes, 175 terminators, and 50 hydraulic plants.

The pipe-type cable circuits selected for this project were subjected to abnormal hydraulic conditions that greatly exceeded the acceptable minimal operational pressures recommended. This project was conceived to test and review data collected on existing PSE&G 138-kV and 230-kV transmission cables that were subjected to full operational loads while operating under extremely low to zero hydraulic pressures. This report documents the results from the first of these cable circuits to be analyzed.

Objectives

Using internal data and information, combined with field dissolved gas analysis (DGA) data collected, PSE&G's Transmission Plant and Engineering (TP&E) Department will establish cable insulation degradation as a result of unusual operational hydraulic pressures. From the data collected, TP&E will develop an insulation degradation baseline on the four HPFF-PTC circuits. The data will not only depict the existing condition of the circuits, but also provide an opportunity for future testing, data collection, and evaluation of damages to cables, including shortened life expectancy as the result of extraneous operational conditions. PSE&G's underground transmission technicians will be present to observe the new sampling technique. This new sampling technique will be administered by DTE Energy personnel.

This project will address issues and questions such as the following:

- Are older transmission cables a source of significant future problems and expenses for utilities, as their 40-year life expectancy predicts?
- Is there a correlation between low-pressure operational conditions of HPFF-PTC cables and cable life expectancy? If so, is it linear or exponential?
- Can HPFF-PTC circuit failures be predicted with reasonable accuracy?
- Is it possible to project where failures are going to occur and allocate replacement funds accordingly?
- What impact does the sampling technique have on the results?
- What are the advantages of the new sampling technique?

2
DGA TESTING

Background

During the blackout of August 2003, several 138-kV and 230-kV HPFF-PTC circuits were operated with little or no fluid pressure. The following circuits were affected:

- E-1331: North Avenue to Passaic Valley Sewerage Commission (138 kV)
- T-1346: North Avenue to Bayway (138 kV)
- Q-1369: Bayway to Doremus (138 kV)
- O-2267: Waldwick to Fairlawn (230 kV)

Operation of the system at pressures less than 100 pounds per square inch (689.4 kilopascals) is likely to subject the cable system to an irreversible process of partial discharges in the insulation of the cable, splices, and terminations as well as gasification of the dielectric fluid. Partial discharges in the cable insulation will shorten the life of the cable system. Gasification of the dielectric fluid results in a loss of its dielectric strength. The extent of damage caused to the previously listed cable circuits needed to be assessed by available diagnostic tests.

Immediately following the blackout, PSE&G’s TP&E conducted a number of tests, including bleeding or venting of gas, DGA, and measurement of dielectric fluid moisture content. In addition to these tests, one measurement that is recognized to yield a good indication of the general condition of paper-insulated cable systems is the insulation dissipation factor (DF). This test is recognized as a primary dielectric measurement in industry standards. The capability to perform this test in the field was developed under an EPRI research project in 1993 and is now available through a licensed EPRI contractor (Power Delivery Consultants [PDC]) to measure the DF on existing 138-kV and 230-kV pipe type cable systems. A recommendation was made by TP&E to conduct field tests on the four circuits affected by the 2003 blackout. Many of PSE&G’s HPFF-PTC systems are operating beyond their 40-year life expectancy.

Cable System Condition Assessment Activities

In 2004, a project was put together as an EPRI-PSE&G tailored collaboration project, and PDC was contracted to perform the measurements and provide an overall condition assessment of cable insulation based on the DF. Testing on all four circuits was completed by the end of June 2004. The 2004 project concluded that the failure did not result in any significant general deterioration of the previously listed circuits. However, the DF measurements could not detect localized deterioration. DGA testing should be used to detect any localized issues at the terminations and/or manholes.

As a follow-up to the DF testing, PSE&G and EPRI joined again to perform DGA on the four circuits. Funding of the project limited the DGA test to a single circuit—the O-2267. This circuit has the following descriptors:

- Waldwick Switching Station to Fairlawn Switching Station
- Original circuit installed in 1982
- Copper, 138-kV, 2000 thousand circular mils (kcmil), compact segmental, and 3-1/C

DTE Energy was contracted by EPRI to perform the DGA testing using an innovative sampling technique—the EPRI Disposable Oil Sampling System (EDOSS)—developed by EPRI and licensed to DTE Energy. Therefore, this project strived to accomplish two goals: to analyze the impact of low pressure on the circuit and to introduce the EDOSS technique to PSE&G employees (training).

This project recovered EDOSS samples from manholes 5A and 6A and terminations at Waldwick and Fairlawn substations. The samples were then taken back to DTE Energy for analysis. DTE Energy's report on the results of this analysis are fully documented in Appendix A. A summary of the conclusions is presented in the following section.

Evaluation of New Sampling Technique

The project served as a training session for PSE&G Transmission, which was administered by DTE Energy, and as an opportunity to evaluate a new sampling method. The EDOSS method of sampling used a vacuum-sealed jar to receive the fluid, thereby minimizing the potential for contamination. The results are analyzed with dedicated EDOSS equipment at DTE Energy. In contrast, the existing PSE&G sampling and analysis method uses a cleaned and heat-dried syringe to capture the fluid. Samples are taken to PSE&G's Maplewood Lab for analysis. Both methods result in a good sample and valid results.

For PSE&G, EDOSS represented a new sampling and analysis method for performing a DGA on the dielectric fluid used in the HPFF-PTC systems. To evaluate the new method, a cost comparison was made for two different EDOSS scenarios against the existing PSE&G method. The two EDOSS options were as follows: (1) upgrade PSE&G's Maplewood Lab to receive and process EDOSS samples or (2) mail the EDOSS samples to DTE Energy.

The results of the analysis are described in Tables 2-1 and 2-2. The comparison assumes 100 DGA samples analyzed in a year. (The transmission average is currently 30 per year.)

Table 2-1
Option A: Upgrade PSE&G Lab

Consideration	EDOSS Method	Existing PSE&G Method
Upgrade Maplewood Lab (include training)	$100,000	N/A
Sample jars (100)	$10,000	$5,000
Sample time	15 minutes	25 minutes
Dollar value of sample time difference (assume 100 samples per year)	N/A	$1,666

Table 2-2
Option B: Mail Results to DTE Energy

Consideration	EDOSS Method	Existing PSE&G Method
Delivery cost, annual	$3,000	N/A
Sample jars (100)	$10,000	$5,000
Sample time	15 minutes	25 minutes
Dollar value of sample time difference (assume 100 samples per year)	N/A	$1,666

From reviewing the costs, staying status quo makes the most sense. In addition to the financial impact, by using the local Maplewood Lab, we gain by getting faster results.

Any real savings are believed to be derived from the ability to better predict the health of our cable systems and to better detect deterioration in the cable system in a more systematic way so that future asset replacements can be more effectively planned. While DGA samples are taken on circuits randomly, it would be most beneficial to sample on a more routine basis and to collect and trend all results obtained. Having trend data for a given circuit over time could lower operational costs and improve reliability by helping PSE&G to avoid premature replacement of cable circuit and to identify necessary corrective action for an impending failure, the price tag of which failure could reach $1.5 million.

Conclusions

The following conclusions can be made:

- A couple of the DGA results showed a high acetylene level, which is indicative of arcing. Therefore, it would be prudent to add valves and perform additional sampling on this circuit.
- This project was limited to analysis of one of the four circuits impacted by the power failure of 2003. Therefore, testing on the other three circuits is advisable.

- The EPRI DGA sampling method EDOSS is purer and swifter than the DGA method used at PSE&G. The results from EDOSS are analyzed at Detroit Edison Lab; this would impede quick results but would provide for technical analysis. If PSE&G's Maplewood Lab were to receive the EDOSS samples, the lab would have to purchase testing equipment. Also, Maplewood Lab provides only results and no analysis or recommendations. TP&E's opinion is that EDOSS is only marginally more sophisticated than the DGA system currently used at PSE&G. We do not see the need to deploy the EDOSS at PSE&G because the current DGA method is satisfactory.

A
REPORT ON DGA AND FLUID RESULTS FOR PSE&G'S 230-KV CABLE SYSTEM, CIRCUIT O-2267

Report by Nirmal Singh of DTE Energy (edited), April 19, 2006

The purpose of this report is to convey the highlights and recommendations of the recent DGA of PSE&G's Waldwick-to-Fairlawn, 230-kV circuit (O-2267) so that PSE&G can plan further action. The DGA and related fluid results on samples taken April 4–5, 2006 are presented in the attached table. The samples were taken April 5–6, 2006 and analyzed on April 8–9, 2006. While other business delayed this report, had the data raised some serious concerns, we would have, of course, contacted you on April 10.

Analysis

Based on a careful review of the data and its relationship to DTE Energy's extensive laboratory and field data generated over a large number of EPRI projects and otherwise, the following comments are made:

1. Of all the gases, acetylene is the single most important gas. A review of the table (Row 7) shows that acetylene was present in all the samples, ranging from 1.2 parts per million (ppm) to 13 ppm. Acetylene is associated with strong electrical activity involving a visible discharge, however faint. Literature mentions that acetylene results from an arcing, and arcs always show visible light. The formation of this gas is not very common and should be taken seriously. This demonstrates that the previous loss of pressure experienced by this 230-kV cable resulted in this arcing. It is important to compare these observed acetylene levels with any previous data.
2. Compared to HPFF terminations, acetylene is seldom observed in splices. Thus, the acetylene in the two splices, namely, 5A (Column 2) and 6A (Column 3), as shown in the table, poses concern. All other splices should be sampled, regardless of the elevation, to establish how their acetylene behavior differs from that of 5A and 6A.
3. Once we find acetylene in an appreciable amount in a splice (or a termination, for that matter), as is the case here for the two splices, it is important to establish the maximum level by moving fluid and taking DGA sample(s). It is recommended to access the fluid around the factory insulation and the hand-applied interface and into the cable—say, about 10 feet (3.05 meters). During draining, the fluid would essentially come from the pumping side. Two draining installments for the splice (depending on the fluid volume in the splice) and one to reach into the cable (again, depending on the volume per foot of pipe) would suffice. Depending on the determined acetylene levels, a better assessment of the cable and any possible action can be made. A situation involving stable or decreasing acetylene will be preferable.

4. As to the terminations, the very first sample for Phase 3, Waldwick Substation (Column 4), was taken at the pipe (referred to as the *lower pipe sample*), with the sample yielding 13 ppm of acetylene, the highest level measured. Since the fluid came from the riser pipe, with some influence of the facing fluid feed line, it follows that the riser pipe may have higher concentrations of acetylene that need to be established. This can be readily accomplished by draining the riser fluid. It is noteworthy that the Phase 3 (or Phase C), which is within a foot (0.3 meter) of the lower valve, also showed a higher acetylene level, 9.5 ppm. The acetylene concentrations for Phase C at the top and around middle were found to be 2.8 ppm and 3.4 ppm, as shown in Columns 7 and 8. For Phase 2 (or B), the highest acetylene was observed at the bottom of the termination (lower portion of the spool), at 7.9 ppm (Column 10). The acetylene data for the two samples at the top of Phase 2 were much lower and constant at 1.2 ppm, irrespective of draining, indicating that the high acetylene level of 7.9 ppm falls to stable values. For Phase 1, only the top samples were taken, resulting in 3.8 ppm and 4.0 ppm of acetylene. According to the data sheet provided by PSE&G, the bottom of the Phase 1 (or A) termination was not sampled, presumably due to inclement weather.
5. For Fairlawn Substation terminations, the three samples (one at the bottom and two at the top) showed basically the same acetylene trend. Again, the highest acetylene value at the bottom is noteworthy.
6. The formation of acetylene is almost invariably accompanied by a larger concentration of ethylene than ethane, resulting in a ratio of these two gases being greater than one (or close to one). This was true for the entire applicable data, as shown in the table. The relatively higher presence of saturated hydrocarbon gases (methane, ethane, propane, isobutene, and so on) in the Phase 1 termination (Columns 14 and 15), particularly in its upper portion, is ascribed to some contamination of the original pipe filling fluid with such gases. The concentrations of the rest of the gases, other than those already mentioned, are in order.
7. The low concentrations of carbon oxides observed in the splices demonstrate that the cable insulation has experienced minimal, if any, aging based on the comprehensive EPRI report *Transmission Cable Life Evaluation and Management* (EPRI report TR-111712) on the Waltz Mill HPFF cable aging project.
8. The quality of samples taken by PSE&G personnel was good, except for two cases showing high nitrogen content (Columns 5 and 10). However, it does not impact the results.
9. All the fluid data shown in the lower portion of the table (moisture, dielectric strength, percent DF at 100ºC [212ºF], and peroxide content) are excellent, showing that the fluid was well degassed and is characterized by high dielectric quality.
10. The extremely low furan content shows that the paper has experienced minimal, if any, aging, supporting the conclusion drawn from the carbon oxides levels.
11. The specified viscosity of alkylbenzene fluid for HPFF cables is 100 Saybolt Universal Seconds (SUS) at 100ºF (37.8ºC). The PSE&G specifications should conform to this 100-SUS viscosity. However, the measured viscosity was found to be 70 SUS at 100ºF (37.8ºC); it is the lowest we have ever measured for an HPFF cable system. The low viscosity means that there would be a greater mixing of the pipe and impregnating fluid over time. This situation can be accepted in this case. However, such a low viscosity should be avoided. In fact, the vast majority of static cables employ a viscosity of 500 SUS or more (even 750 SUS at 100ºF [37.8ºC]).

Conclusions

Based on the DGA and fluid data, the following comments are made:

- The cable has experienced minimal aging.
- However, the situation of acetylene must be addressed at splices 5A and 6A as well as the riser pipe associated with Phase 3 (or C) termination at Waldwick Substation, following the outline procedure. The objective is to establish the highest possible acetylene level generated in the cable system during its inadvertent loss of pressure incident.
- It is important to sample all the remaining splices—an easy first step to address. Depending on the PSE&G safety rules, the lower pipe of the Phase C termination at Waldwick Substation can be sampled live with due prudent care.
- A minimum viscosity of 100 SUS at 100ºF (37.8ºC) is recommended as a pipe fluid for static HPFF cable systems. However, it is highly preferable to employ a viscosity of 500 SUS at 100ºF (37.8ºC) for static lines, as is the normal industry practice.

Table Column #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
MH#	5A	6A	PH3, lower	PHC Bottom	Top PH 3-1	Top PH 3-2	Top PH 1-1	Top PH 1-2	Phase 2	Top PH 2-1	Top PH 2-2	PH1 body	Top PH 1-1	Top PH 1-2	PH2 body	Top PH 2-1	Top PH 2-2	PH3 body	Top PH 3-1	Top PH 3-2
Methane, ppm	44	39	29	31	31	30	30	29	32	30	30	54	234	222	18	19	17	19	16	16
Ethane, ppm	24	22	19	19	19	19	19	19	19	19	19	38	135	124	18	22	20	19	19	19
Ethylene, ppm	25	27	38	32	23	23	24	24	30	18	18	46	100	97	32	30	30	34.5	28	27
Acetylene, ppm	**6.5**	**7.2**	**13**	**9.5**	**2.8**	**3.4**	**3.8**	**4.0**	**7.9**	**1.2**	**1.2**	**11**	**7.2**	**8.8**	**10**	**5.0**	**6.5**	**11**	**5.8**	**5.6**
Propane, ppm	67	58	43	42	40	41	42	42	41	41	41	99	266	239	66	72	68	65	66	66
Propylene, ppm	30	30	35	33	29	30	30	30	32	28	28	66	196	176	38	36	36	40	36	35
Isobutane, ppm	8.3	8.0	8.6	8.2	8.2	8.2	8.1	8.2	8.1	8.2	8.4	11	30	27	6.4	7.1	6.8	7.1	6.6	6.4
n-Butane, ppm	14	21	14	14	14	14	14	15	15	15	14	37	75	67	30	33	32	30	31.5	31
t-2-Butene, ppm	0.0	0.0	0.4	0.0	0.0	0.0	0.3	0.3	0.5	0.4	0.2	1.4	5.2	3.2	0.3	0.5	0.3	1.0	1.1	0.9
1-Butene, ppm	25	22	18	17	18	16	17	16	18	17	16	51	126	103	34	53	52	42	52	49
Isobutylene, ppm	98	93	105	95	90	91	90	91	95	87	87	155	527	451	81	77	77	85	68	69
Hydrogen, ppm	260	228	67	105	87	80	83	93	106	104	92	84	109	114	69	88	97	73	86	92
C. Monoxide, ppm	43	45	13	48	45	49	52	48	63	93	103	12	15	16	14	15	16	17	18	19
C. Dioxide, ppm	415	435	426	416	400	391	381	389	395	406	358	219	243	272	266	228	229	269	231	232
Nitrogen, ppm	117,216	117,800	120,405	179,527	126,149	126,431	126,695	127,958	189,297	129,417	130,498	128,467	132,577	149,282	112,504	134,051	134,363	128,016	137,543	134,636
Moisture, ppm	6.01	9.90							4.00						4.59					
Dielectric Strength ASTM D877, kV	46.6	47.1							46.4						49.8					
Dissipation Factor (DF) @ 100C, %	0.524	0.495							0.740						0.619					
Peroxide content, ppm	n.d.	n.d.							n.d.						n.d.					
Refractive Index @ 20C	1.4938	1.4933							1.4924						1.4947					
Viscosity (SUS) @100F	70	70.1							72.1						70.3					
Furan, ppb	1.2	n.d.							2.1						n.d.					

n.d. = none detected

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