WATER TREEING AS A CAUSE
OF POLYETHYLENE POWER CABLES REPEATED FAILURES

1. Introduction

It has been known from in service experiences that presence of moisture in contact with various types of insulation can greatly accelerate its deterioration [1, 2]. The extent of insulation deterioration occurs because of water treeing, independently on species of polyethylene (thermoplastic, crosslinked) and kind of cable construction. Water treeing have been found to cause premature cable failure [3, 4]. It has been also observed that after first failure, irrespective of its cause, there are other successive break-downs after some months in service [5, 6]. Laboratory tests has been performed to explain this phenomenon.

2. Environmental exposure of cable insulation under service and test conditions

There are some the most important factors affecting destructively on polyethylene insulation under moist conditions:

1) temperature, its gradient and fluctuation;
2) electric field, its frequency and gradient;
3) mechanical stress;
4) compounds dissolved in water.

Each of these factors exerts an influence on water treeing and this is impossible to describe its interaction by theoretical way.

Insulation temperature depends on conductor load current. This current should be near to the rated one in a correct designed and used power line. The natural temperature drop exist between conductor and outer insulation layer under steady-state. The lengthwise temperature difference can be observed in some particular cases too. Insulation temperature fluctuations are caused by load current variations and environmental temperature changes.
ging. It has been assumed that the operating temperature of thermoplastic polyethylene cable insulation should not exceed 70°C, and 150°C under short-circuit conditions near by inner conductor as well as 25°C near by outer one.

Electrical stress is practically constant in service and its average value for Polish cables varies from 1.4 MV/m at rated voltage 3,6/6 kV to 2.25 MV/m at voltage 18/30 kV. This stress amounts to 1.7 MV/m and 2.6 MV/m respectively for maximum admissible power line operate voltage. Furthermore, we can observe overvoltages existence caused by switching processes or earth fault. Switching surge duration is too short (a few milliseconds) to make an influence on water treeing growth. Earth fault overvoltage, having longer duration (1–2 s) can involve some water treeing effect.

Electric field distribution in cable insulation depends on its geometry. Usually we have a single-core polyethylene insulated cables with radial electric field distribution. Electric field gradient always exists in this kind of insulation form and its quantity depends on conductor diameter (cross-section). Electrical stress difference between inner and outer insulation layer doesn’t exceed a few tens of percent for all rated conductor cross-sections (50–625 mm²).

Electric field frequency is constant in service conditions. Mechanical stress may occur in some moments of cable life. The first and probably the most dangerous mechanical stress can be formed in insulation during cabling using too much bending and tensile forces. Microcracks made by this stresses will render under service insulation life. Moreover, mechanical stress may appear in cable insulation because of soil layer displacement especially in mining and urban area.

Chemical constitution of water which affects on polyethylene insulation is unknown. Undoubtedly, it is mineral compound solution rinsed out in soil and their concentration varies in every case.

2. Results

Basing on this analysis and previous experiences, insulation ageing program was elaborated. Ageing process consist of mechanical, electrical and thermal stresses. Thermal stress is produced by loading conductor current. Three current values have been selected to make three different insulation temperatures. Measured on the conductor shield it was respectively 30, 54 and 75°C for current 100, 150 and 270 A.

Other measured temperatures are shown in Table 1.

The maximum temperature value at this samples is near to the admissible operating temperature of thermoplastic polyethylene insulation.
<table>
<thead>
<tr>
<th>Sample</th>
<th>Current [A]</th>
<th>Temperature °C</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>K8</td>
<td>100</td>
<td>36</td>
</tr>
<tr>
<td>K9</td>
<td>100</td>
<td>36.4</td>
</tr>
<tr>
<td>K3</td>
<td>180</td>
<td>54.2</td>
</tr>
<tr>
<td>K4</td>
<td>120</td>
<td>51.4</td>
</tr>
<tr>
<td>K7</td>
<td>180</td>
<td>53.8</td>
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<tr>
<td>K10</td>
<td>270</td>
<td>74.3</td>
</tr>
<tr>
<td>K11</td>
<td>270</td>
<td>74.6</td>
</tr>
</tbody>
</table>

Table 1

The voltage applied during laboratory test had a value to generate overage electrical stress:
- Approximately twice higher than maximum operating stress, namely 4.4 MV/m,
- \( \sqrt{3} \) times less than former one, namely 2.5 MV/m.

For this reasons, applied voltage has value respectively 20 and 12 kV.

Some tested cables were exposed to overvoltages modelling switching process. This overvoltages were applied periodically twice an hour for 2 seconds, increasing voltage \( \sqrt{3} \) times in relation to 20 kV. The increased overvoltage frequency in comparison to service conditions, was applied to intensify their influence on water treeing, if any.

Some samples were exposed to mechanical stress before voltage applying. These stresses were produced by cable six-couple winding up around a drum 400 mm diameter. Two cables were stressed at 20°C and the next one at 30°C temperatures.

Polyethylene insulation was wet by putting distilled water or 0.5% and 3% NaCl solution under outer cable jacket just before applying voltage.

Table 2 shows ageing conditions list for all samples.

Considering the above criteria, ageing tests were performed on full size 25 kV, 3 m long, LSF, Al single-core cables, which had extruded conductor shield and tape-graphite insulation shield.

During the test, at the certain time intervals, 30 cm long sections were cut from the part of the cable which was submerged in water. The samples were cut into 0.2 mm thick slices and dyed in methylene blue solution. After 16 hours dying process in 90°C temperature the samples were microscopically examined. The number of trees and volume of examined samples were noted.

Insulation samples of cables removed from service were microscopically examined this way too.
This samples were removed from cables after their second failure. The second break-down place was near to the first one on this cables (a few meters distance).

**Table 2**

<table>
<thead>
<tr>
<th>Sample Nr</th>
<th>Voltage</th>
<th>Load current</th>
<th>NaCl solution density</th>
<th>Over-voltage</th>
<th>Mechanical stress at</th>
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<td></td>
<td>12</td>
<td>20</td>
<td>0 100 180 270</td>
<td>0 0.3 3</td>
<td>5 2 3</td>
</tr>
<tr>
<td>K1</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>K3</td>
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<td>+</td>
<td>+</td>
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<tr>
<td>K4</td>
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<td></td>
</tr>
<tr>
<td>K20</td>
<td>+</td>
<td>+</td>
<td>+</td>
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<td></td>
</tr>
</tbody>
</table>

### 3.1. Laboratory aged cables

Fig. 1, 2 and 3 show water trees density in cables aged laboratory, as a function of time of voltage application. Basing on these diagrams we can describe:

\[ n_y = b \cdot a^{c \cdot t} \]  

or

\[ \log n_y = A \cdot t + \log b \]  

where:

- \( n_y \) — water trees density (mm\(^{-3}\)),
- \( A = c \cdot \log a = \text{const.} = \text{material constant} \)

Expressions \( \log b \) value should be dependent on ageing conditions, e.g., temperature, type of water solution, overvoltages existence, etc.
Fig. 1

- K6 0A
- K8 100A
- K7 180A
- K10 270A
- K3 270A

0.3% NaCl
0% NaCl

20 kV
stresses etc. Equation (2) suggests that \( \log n_v = f(t) \) lines in diagram should be seen as straight lines with a slope \( A \). These lines should be parallelly displaced dependent on ageing conditions. Experimental results are in a good agreement with equation (2) for \( A = 0.01 \) (1/day).

The second term of equation (2) is the most dependent on temperature, as we can conclude from experimental results in Fig. 1-3. Fig. 4 shows water tree density temperature dependence after 150 days of cables ageing. This is logarithmic correlation too, so we can write:

\[
\log n_v = A \cdot t + B \cdot T + C
\]  

(3)

where:

- \( A, B, C \) - parameters,
- \( t \) - ageing time (days),
- \( T \) - temperature (°C).

A quick numerical analysis shows that \( B = 0.092 \) (1/°C). The coefficient \( C \) value would depend on other ageing conditions (mechanical stresses, overvoltages, existence etc.).

Basing on experimental results it could be calculated that:

- \( C_1 = -3.36 \) - for salted water (0.3 and 3% solutions),
- \( C_2 = -4.6 \) - for distilled water,
- \( C_3 = -2.45 \) - in presence of mechanical stresses or overvoltages.

Fig. 1-3 show experimental data (points) and calculated from eqn. (3) results (lines) which are with a good agreement in spite of experimental points scatter. Now, transforming eqn. (3), it is possible to calculate order of magnitude of water tree density in aged cables as:

\[
n_v = 10^N
\]  

(4)

where:

\[
N = A \cdot t + B \cdot T + C
\]

Equation (4) give an easy possibility to watch progress in water treeing in service and laboratory ageing test. So, it could be imagine that a triple change of average insulation temperature induce \( 10^3 \) times (some thousands) change in water tree density; water salting increase that number \( 10^{1.24} \) times (over a dozen or so) because of difference \( C_1 - C_2 \); and mechanical stress give \( 10^{0.81} \) times (several times) change in water tree density caused by \( C_2 - C_1 \) difference. It is clear that temperature influenced the most effects on water tree density.

Conversely proceeding, it is possible to estimate a wet condition time for in service cable knowing water treeing density on its insulations.

It was observed during laboratory tests, some thousand of water trees
growing in 1 mm³ polyethylene insulation, aged at the temperature somewhere round to admissible one. This water tree density produce serious insulation degradation.

3.2. Cables recovered from the field

As it was said before, cables after their second failure were microscopically examined. The second break-down places were found near to the first one, in a few meter distance. This kind of cables failure happens about 1 year after the first one, which have been observed by Bialystok Power Plant Cable Service. This observation may suggest that the water penetrates into the cable after the first failure. The water trees growth degrade an insulation, leading to its second break-down.

The following cables have been tested:

K101 - YHAKX 15 kV, 1x240 mm² Al, 1979-83 in service,
K102 - YHAKX 15 kV, 1x120 mm² Al, 1976-85 in service,
K104 - YHAKX 15 kV, 1x120 mm² Al, 1977-85 in service.

It was concluded above, that counting water trees density in insulation, it is possible to estimate a wet condition time for examined cables. Making an assumption that the average value of insulation temperature in above-mentioned cables ranged 30-35°C, determination of wet condition time have been made. It has been also assumed that the water had a salt solution property at this process.

Effect of overvoltage and mechanical stress were neglected. Results of calculations are shown in Table 3.

<table>
<thead>
<tr>
<th>Cable</th>
<th>( n_v ) (mm⁻³)</th>
<th>Service time (years)</th>
<th>Calc. wet time (days)</th>
<th>Assumed coefficients</th>
</tr>
</thead>
<tbody>
<tr>
<td>K101</td>
<td>1850</td>
<td>4</td>
<td>366-340</td>
<td>A = 0.01</td>
</tr>
<tr>
<td>K102</td>
<td>294</td>
<td>9</td>
<td>307-261</td>
<td>B = 0.092</td>
</tr>
<tr>
<td>K104</td>
<td>132</td>
<td>7</td>
<td>272-226</td>
<td>C = -3.36</td>
</tr>
</tbody>
</table>

Although these results can be taken as an approximate values, it is clear, however, that the cables insulation wetting time was app. one year. It corresponds with service observations.
4. Conclusions

The quantitative investigations of water treeing in laboratory aged and recovered from service polyethylene insulation show that the water treeing phenomenon could be a reason of power cables repeated failures. Water penetrates into the cable after the first break-down and insulation degradation caused by water treeing leads to the second damage in a short time.

In order to prevent cables from repeated failure water retardant polyethylene should be used in a new products as an insulation. The lifetime of buried cables could be extended by permeating a liquid dielectric into the insulation via the conductor or by drying insulation with an inert gas.

An investigation of this methods should be undertaken for Polish cables.

References


5. J. Karczewski: private information, Zakład Energetyczny Białystok.
