PHYSICAL PROCESSES IN THE FLASHOVER OF INSULATORS WITH CONTAMINATED SURFACES

by

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ABSTRACT

This study represents both an experimental and a theoretical approach to the problem of contamination flashover of transmission line insulators. To facilitate mathematical modeling, experiments were done on an insulator of mathematically simple geometry. In order to determine the factors governing surface flashover this insulator was exposed to salt fog and then subjected to high voltage stress. The effects of inert porous surface deposits, fog salt percentage, surface orientation, reignition, and polarity were investigated. A theoretical model was constructed based on previously published theories. Although the theory was consistent with the observations it provided no physical insight into how an electrical discharge bridges a moist film. Several possible physical mechanisms were suggested, but none could be verified from the data at hand.

Slow salt fog tests were done on standard suspension insulators. The effects of porous surface layers, fog salt concentration, voltage, and surface condition were studied, and the effect of voltage on contaminant deposition was investigated. Naturally contaminated insulators were subjected to various conditions of dew formation, fog, and wind to determine the factors most responsible for insulator failure in service.

Specially shaped insulators were tested to determine how geometry affects performance. Insulators with semiconducting glazes were found to suffer no reduction in insulation strength even under severe fog conditions.

Based on the results of the thesis, several interesting lines of investigation were suggested for the future.

THESIS SUPERVISOR: Herbert H. Woodson
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Many people have made important contributions to this study. Particularly helpful was the guidance and counsel of the thesis supervisor, Professor Herbert H. Woodson. His previous experience with the problem assured the continuity of this study with the earlier effort here, and his intuitive insights often led to profitable avenues of research. The other members of the thesis committee, Professors James R. Melcher and Gerald L. Wilson, provided helpful suggestions during the critical final stages of the work. Professor Siggia of the University of Massachusetts carried out the careful chemical analysis of natural contaminants.

The author's predecessor, Dr. Alan J. McElroy of AEP, deserves special mention for laboriously setting up the contamination laboratory and designing the fog chamber. Without this equipment and without his extensive preliminary results, the author would have been unable to concentrate directly on the contamination problem.

A great deal of credit for the success of the experimental phase belongs to Jim Griffiths, an aeronautical engineering graduate employed during the summer of 1970 as a lab technician. All experiments of Chapter 2 and most in Chapter 4 were done with his careful assistance. As other contamination flashover investigators have remarked, finding a technician with a "low standard deviation" is not easy. His cheerful motto, "Photoflo the surface right -- then spray it with bentonite," will long be remembered.

A number of students have worked in the laboratory during

the course of this study. T.C. Cheng assisted with some experiments in the later stages and checked the thesis text for accuracy. Andrew Frederick, Everett Ayers, and Robert Newell conducted Bachelors Thesis research on contamination. Andrew Frederick deserves special mention for making plaster casts of the insulators of Section 5.2 and the painstaking graphical computation of creepage paths, areas, and form factors. Allen Ho assisted with data taking while working on a lab project.

The largest share of credit belongs to the American Electric Power Service Corporation and Mr. Howard C. Barnes in particular for the generous financial support which made this study possible. Two of AEP's operating companies, Ohio Power Company and Wheeling Electric Company, provided field contaminated specimens for testing. The Ohio Brass Company and Lapp Insulator provided special insulator specimens for testing. Discussions with Messrs. Bob Flugum of O.B. and Tom Pinkham of Lapp, as well as with Mikio Kawai of Project UHV were especially helpful in acquainting the author with many practical aspects of the problem.

The expert secretarial skills of Mrs. Barbara Morton and Mrs. Henrietta Jackson were indispensable in preparing the rough and final drafts. Mr. Norman Darling and his drafting staff are responsible for the professional appearance of the figures.

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CHAPTER 1

INTRODUCTION

1.1 Nature of the Problem

The steady growth in the demand for electric power requires the construction of transmission lines of ever increasing capacity. This increased capacity is most easily obtained by increasing the transmission voltage. Overhead lines of 765 kV are now in use and higher voltages are contemplated. Underground cables are also used to transmit power but they are not soon likely to become economically competitive with overhead lines for long distance transmission.

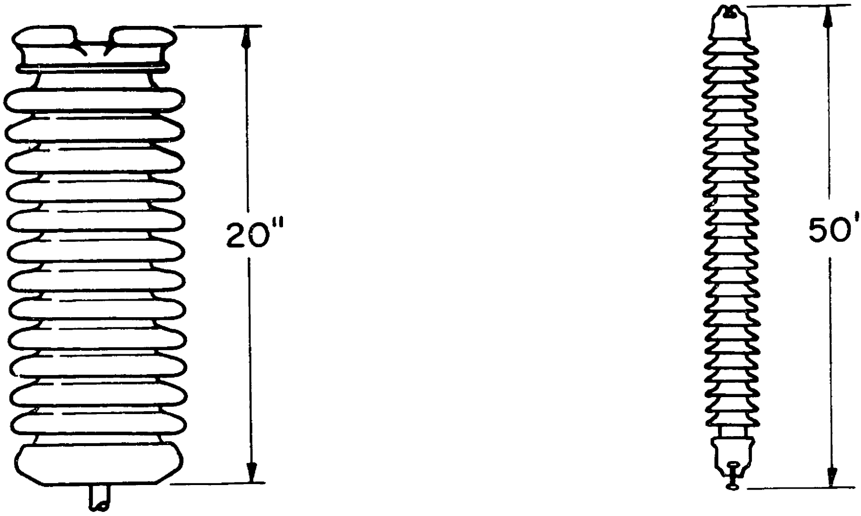
The exposed nature of overhead lines makes their insulation a troublesome affair. The insulation must be resistant to rain, snow, ice, and airborne deposits, as well as to lightning and switching overvoltages.

To meet these demands, the four major types of insulators depicted in Fig. 1.1 have been developed for overhead line use. The earliest appears to have been the pin type insulator which was based on the successful telegraph insulator. It is nothing more than a porcelain shell structure with a groove on top for the conductor and a receptacle on the bottom for the mounting pin. As transmission voltages increased, nested porcelain shells of larger diameter were adopted but eventually voltages were reached where weight and cost made this type impractical.

In the decade before 1910, to meet insulation needs for lines of 100 kV and above, the suspension insulator was developed. These

(a) Locke 35 kV pin insulator manufactured around 1900 showing 3 nested porcelain shells

(b) Modern 10" diameter Ohio Brass suspension insulator



(c) Modern Lapp 66 kV line post insulator

(d) Modern Siemens long rod insulator for 110 kV

Fig. 1.1 Major Types of Line Insulators

insulators can be linked in series to give a string of whatever length is necessary for adequate insulation. The familiar cap and pin type and the Hewlett interlink type found widespread early use, but the cap and pin is now standard because of greater mechanical strength and ease of manufacture. The great advantage of the suspension type is its flexibility. Any number can be hooked in series for electrical strength, strings can be paralleled for mechanical strength and either vertical mounting or horizontal mounting in tension is possible. Since the same basic insulator can be used for many different voltage levels, inventory problems are substantially reduced.

Another type in general use today is the line post. This is simply a porcelain column with rain sheds which has sufficient mechanical and electrical strength for the intended application. Both horizontal and vertical mounting are possible. This type is in use up to 230 kV.

The long rod type is sometimes used and is particularly favored by the Germans. Although various mounting arrangements are possible, it is usually used to suspend the conductor below the tower cross-arm. Like the suspension type they can be linked in series for higher voltages. They are not popular in this country partly because they are vulnerable to gunfire.

At the higher transmission voltages a problem known as contamination flashover becomes increasingly important relative to other insulation troubles. This type of flashover usually occurs after insulators have been coated with airborne particles containing conducting salts. If the insulator surface is then moistened, say by fog or dew, the surface becomes conducting and dry bands form due to power dissipated in the film. The voltage stress is then concentrated on these narrow dry bands which often break down, causing visible scintillations on the insulator. If the contamination is severe enough, these scintillations can bridge the insulator and trigger a power arc.

According to a recent survey (Nasser, 1970) there are many sources of dangerous contamination including for example, sea salt, road salt, cement, fly ash, bird droppings, fertilizer, and many types of industrial emissions. Flashovers have occurred in weather ranging from fog and dew to drizzle and wet snow. Troubles occasionally comes from unexpected sources as in one case after a sugar plantation became infested with a certain insect. After feeding on the sugar, the bloated insects would struggle into the air looking for a safe place to land. This turned out to be on transmission line insulators which were provided at convenient intervals. While dozing on the insulators they would excrete a sugary substance which eventually formed a coating. During heavy tropical dews this would turn into a sticky syrup leading to flashover. There seems to be no record of the countermeasures employed in this case, but for more ordinary cases the insulators are periodically washed or greased, the string length is increased, or specially designed insulators are used. These methods meet with mixed success which is not surprising considering the wide range of contaminants encountered. What works in one case is often useless in another.

1.2 Previous Attacks on the Problem

The contamination flashover problem has a long and unpleasant history. According to Taylor (1948) an oil filled anti-fog insulator was patented as early as 1878. A few years later an insulator with an internal heating element to keep the surface warm and dry was patented in Norway. Later designs included increased creepage path length, exposed creepage path for washing by rain, complicated labyrinth shapes to maintain a dry surface inside, metal hoods to keep fog away, pumping hot oil through the insulator, capacitive voltage grading, and semi-conducting glazes. Most of these methods met with little acceptance, not because they didn't work, but because they were expensive and impractical.

Much of the research in this area has been done by the Germans. Dr. Weicker of Hermsdorf considered the problem early in the century Somewhat later, around 1930, Dr. Obenaus carried out experiments on his famous water filament model which solidly established the importance of surface resistivity and of dry zone formation. Recent scientific attempts to understand the flashover mechanism began with the work of Drs. von Cron at Siemens (1952) and Frischmann at Dresden (1956). In 1958 Professor Obenaus outlined the method of calculating discharge extinction which was worked out in detail by his pupil Neumärker (1959). The investigations of Reverey (1955) on test methods and the interesting theoretical work of Näcke (1966) on arc stability should also be mentioned.

In Britain serious research seems to have begun around 1930 as lines installed after the war began to get into contamination trouble. In that year the Central Electricity Board asked the National Physical Laboratory to look at the problem, but the study apparently didn't get too far (Standring, 1934). Messrs. Ryle and John and Dr. Clark carried out some other early studies. Over the years Dr. Forrest has carried out long term tests on insulators exposed to natural contamination. Recently Alston (1963), Hampton (1964), and Wilkins (1969) have considered the theoretical aspects of flashover.

Pioneering work was done in the U.S. by Austin of Ohio Brass who studied the importance of surface resistance (1911). One of the most comprehensive early studies was begun in 1929 at the Ryan High-Voltage Laboratory at Stanford University (Cozzens and Blakeslee, 1948). This study was prompted by frequent flashovers during fog of a 115 kV line and complaints of audible and radio noise. Considerable efforts were made to artifically simulate natural conditions. A detailed chemical analysis of natural contaminants led to the selection of an artificial contaminant containing eight separate ingredients. Comparative tests were done on different insulator shapes and the merits of artificial washing were studied. These tests were fairly extensive and represented a great deal of time and expense. The results aided in the selection of insulation for the Boulder Dam-Los Angeles line, which, after all was said and done, turned out to be standard suspension units. Other early studies include those of Wood (1930), Frey (1948), and Adler, Wickham, and Oldacre (1948).

Recent studies, particularly those of Kawai, Macchiaroli, and Turner, have contributed to the development of testing procedures. Kawai (1970) has experimentally confirmed theoretical predictions of Boehne (1967) concerning the non-linear variation of flashover voltage with string length. Extensive research has been carried out by the insulator manufacturers as well as by some of the affected utilities, but unfortunately only a few of the results are made generally available (Flugum, 1971 for example).

Research has been done in other countries, notably France, Japan, the Soviet Union, and Italy, but the results are by and large similar to those of the countries discussed.

Anyone wishing to delve more deeply into early or recent investigations will find ample material in the reference list at the end of this thesis.

1.3 Scope of this Study

The present investigation began in the Fall of 1969 and represents a continuation of the study begun by A.J. McElroy in 1966. The principal motivation was the need to understand the cause of contamination flashovers occurring on the American Electric Power System. It became clear early in the study that the physical processes involved in contamination flashover needed further investigation. To this end McElroy constructed an artificial fog chamber which closely duplicated natural conditions. He studied dry zone formation and discharge processes on naturally and artificially contaminated insulators as well as on a flat plate model. Significant results were obtained pointing the way to future research. These results have been described in detail (McElroy, 1969; McElroy et al., 1970; Woodson and McElroy, 1970 a,b).

The present work concerned itself with several aspects of the problem. Since it was felt that the way in which initial small scintillations elongated to bridge an insulator was not yet understood, extensive discharge experiments were carried out, and the results compared with the theoretical predictions of others. Some of the contradictions between various theories were resolved by suggesting physical mechanisms more consistent with experimental results obtained here and in other testing laboratories.

Once the discharge mechanism was better understood, tests could profitably be carried out on actual insulators. Many tests were done on standard suspension insulators with artificial contamination. Interesting results were obtained concerning the effect of fog conductivity, applied voltage, and the presence of non-conducting porous surface layers. To relate the study to operating experience tests were done on naturally contaminated insulators removed from service. The effects of wind and condensation were particularly studied. A test procedure was carefully developed which, it is felt, can help determine how close an insulator removed from the field is to flashover.

Another group of tests was done on specially shaped insulators to see if shape variations might improve upon the contamination performance of the standard suspension type. Insulators with semi-conducting surface glazes were also tested.

In addition to these experiments, a relatively thorough search was made of both the U.S. and foreign literature. About a dozen complete translations were made of German papers with fragments of other being translated. This study of the literature turned up results of many excellent early investigations, some of which seem to have been forgotten over the years. It was originally intended to compile a complete contamination bibliography, but this was soon discovered to be impractical. Nevertheless most major papers are included in the references. A search of patents back to 1960 was made which turned up some novel ideas but nothing of any real relevance to the present study.

CHAPTER 2

DISCHARGE EXPERIMENTS

2.1 Introduction

This chapter describes a series of experiments done with models in an attempt to simulate the flashover process. The first part of the chapter describes experiments on a simple concentric electrode flat plate insulator. Various effects were investigated, including the dependence of the flashover voltage on the contamination level, the effect of the inert contaminant, and the effect of plate orientation. At the end of the chapter, another experiment is described in which an arc was drawn out between two fine copper wires in series with a resistor, the object being to simulate the discharges occurring on a contaminated suspension insulator.

2.2 Description of the Flat Plate Insulator

Actual suspension insulators are difficult to analyse theoretically since they have a mathematically complex shape. It is much more conveninet to experiment with a simpler shape for which the resistive form factor between the arc root and the opposite electrode can be calculated directly. Deducing the series resistance indirectly from the data is thus avoided, resulting in less ambiguity of interpretation.

Two electrode arrangements have particularly simple mathematical expressions for the resistance in series with the arc: a long cylinder with electrodes at each end, and a flat plate with an inner disc and a concentric outer ring for electrodes. Smooth glass cylinders, one meter long, have already been used by von Cron (1957) to investigate the flashover of long rod insulators. However, the flat plate better simulates the standard suspension insulator, and has been used by McElroy (1969) in this connection. The same insulator was used in this study. Figure 2.1 depicts the insulator. The insulating plate is a 12" square slab of pyrex. Provisions are made for mounting a 1 3/4" diameter inner disc electrode and a 10" inner diameter outer ring, both made of brass. A guard ring, which may be put in place during the application of fog will keep a 1/8" strip around the inner electrode dry, simulating an initial dry band.

2.3 Flat Plate Test Procedure

The usual procedure for flat plate testing consists of two parts. First the pyrex insulator surface is prepared, and second, the insulator is subjected to fog followed by the application of voltage.

To prepare the surface, it is first cleaned with hot tap water and detergent, then rinsed thoroughly with hot water and wiped with Kimwipes.* Seven drops of Kodak Photoflo-200** are applied and spread evenly over the surface with the corner of a Kimwipe. The entire surface is then lightly wiped with a dry Kimwipe to remove any excess Photoflo. The result is a surface with a uniform thin detergent film. This film serves to break up the surface tension of water drops on the surface, causing a more uniform deposition of both bentonite and fog.

The bentonite is next applied using an electric vibrator paint

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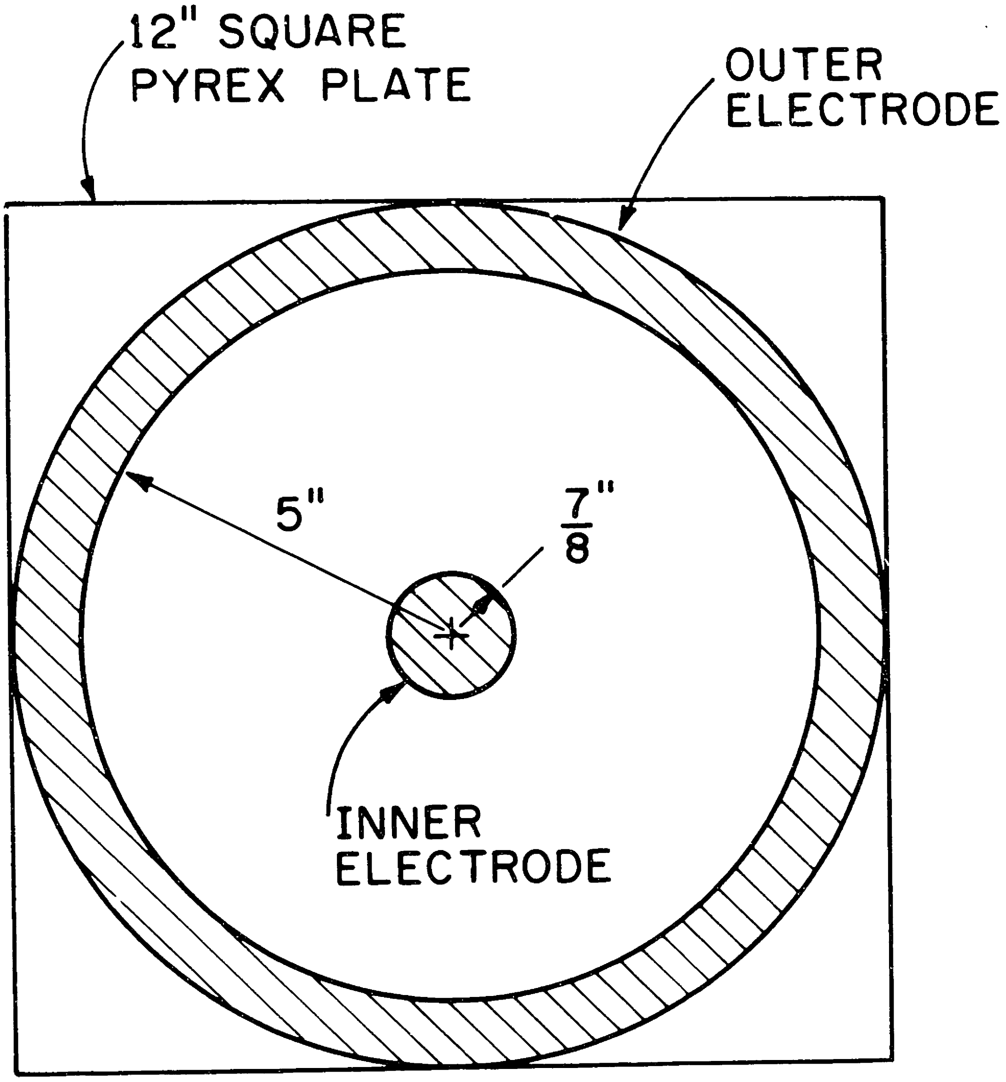
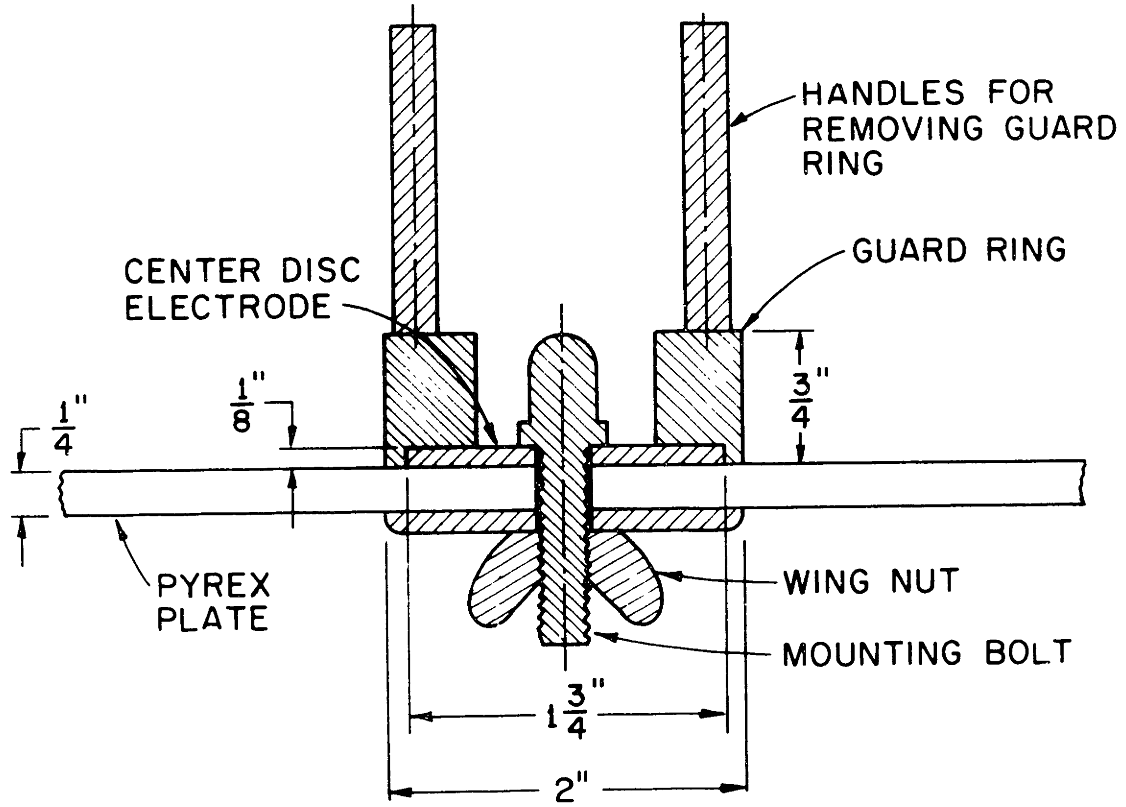
* Registered Kimberly Clark trademark.

** Registered Eastman Kodak trademark.



(a) Top view of flat plate showing arrangement of electrodes

Fig. 2.1 Flat plate apparatus



(b) Cross sectional detail of center electrode with guard ring in place

Fig. 2.1 (cont.)

sprayer. The slurry consists of 15 grams of bentonite in 500 ml. of distilled water. The coating is sprayed on with a scanning motion of four passes lasting about one second each. The plate is then dried with a fan, rotated 90°, and sprayed again. This procedure is repeated until the desired bentonite level is obtained. In a few trials to be discussed later, kaolinite was substituted for bentonite, but the procedure was otherwise identical. In several cases, no inert coating was used, in which case the process terminated with the application of the Photoflo.

After the plate has dried, the electrodes are bolted on, and the insulator is put in the fog chamber. The guard ring is placed over the center disc and a lead is attached to it in order to monitor the resistance. The lead runs to a Wheatstone bridge which near balance applies less than 50 volts a.c. across the surface. The bridge voltage is sometimes reduced in order to avoid any possible heating of the water film. The outer electrode goes to ground through the monitoring equipment and a knife switch. Figure 2.2 shows the arrangement of the test circuit.

Once the plate is in position with the sprayed surface facing upward, salt fog is applied. The resistance is monitored, and when the desired level is reached, the fog is shut off. The chamber door is then opened, the guard ring removed, the center electrode connected to the high voltage terminal, the chamber door replaced, the knife switch opened and the high voltage source readied. The voltage is then raised to the desired level, the discharge current recorder started, and the knife switch closed. After flashover or after all discharge activity has ceased the discharge recorder is stopped, terminating the test.

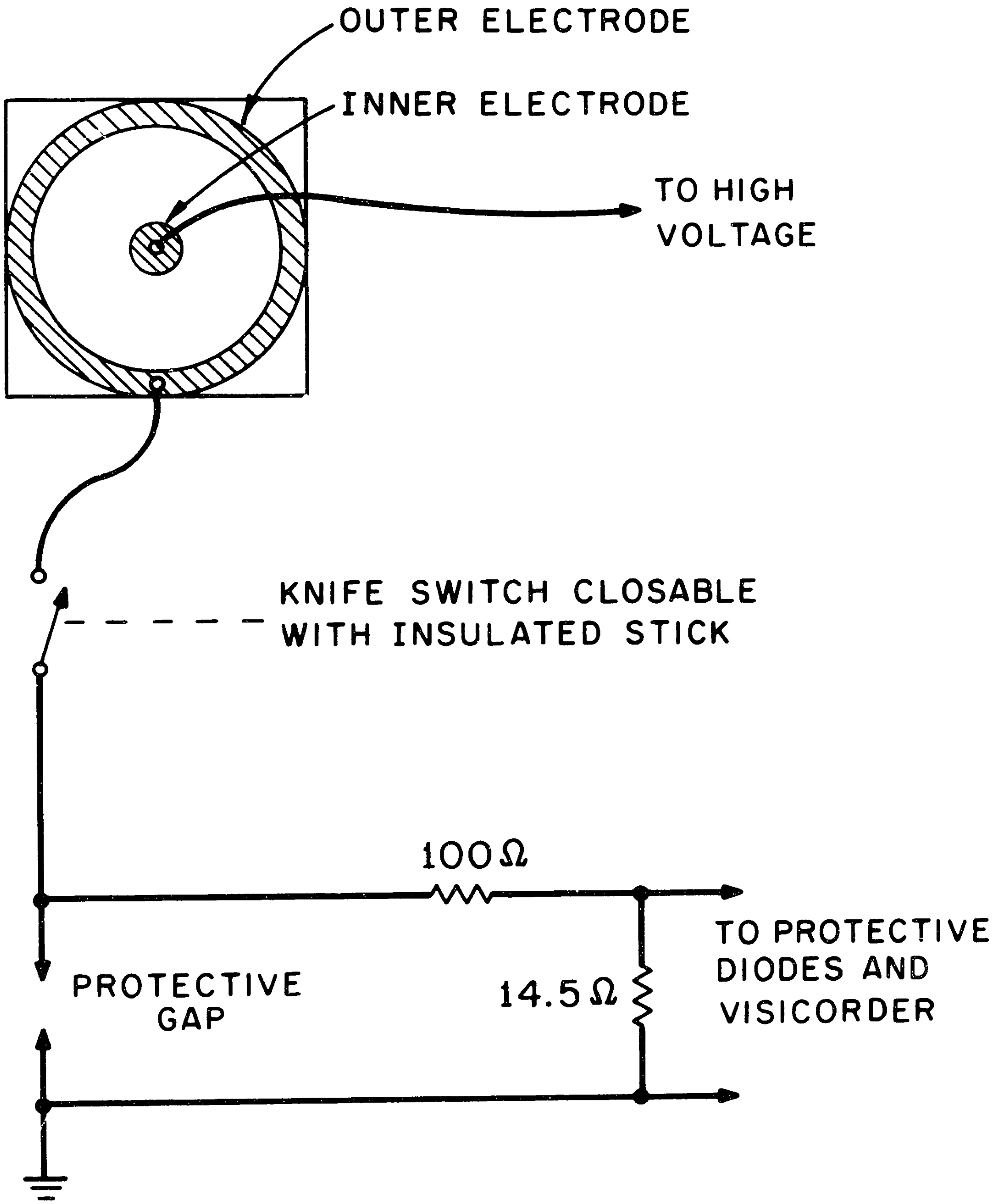


Fig. 2.2 Flat plate test circuit

After making sure the voltage has been removed, the plate can be taken out for later washing to determine the amount of bentonite. The entire procedure was designed to prevent accidental application of voltage to the test personnel. Two well-trained individuals can carry out the above tasks so that only 60 seconds elapse between removal of the door and application of voltage. It was found the resistance changes less than 1% during this interval.

Any exceptions to the procedure described above will be noted in the following sections as they occur.

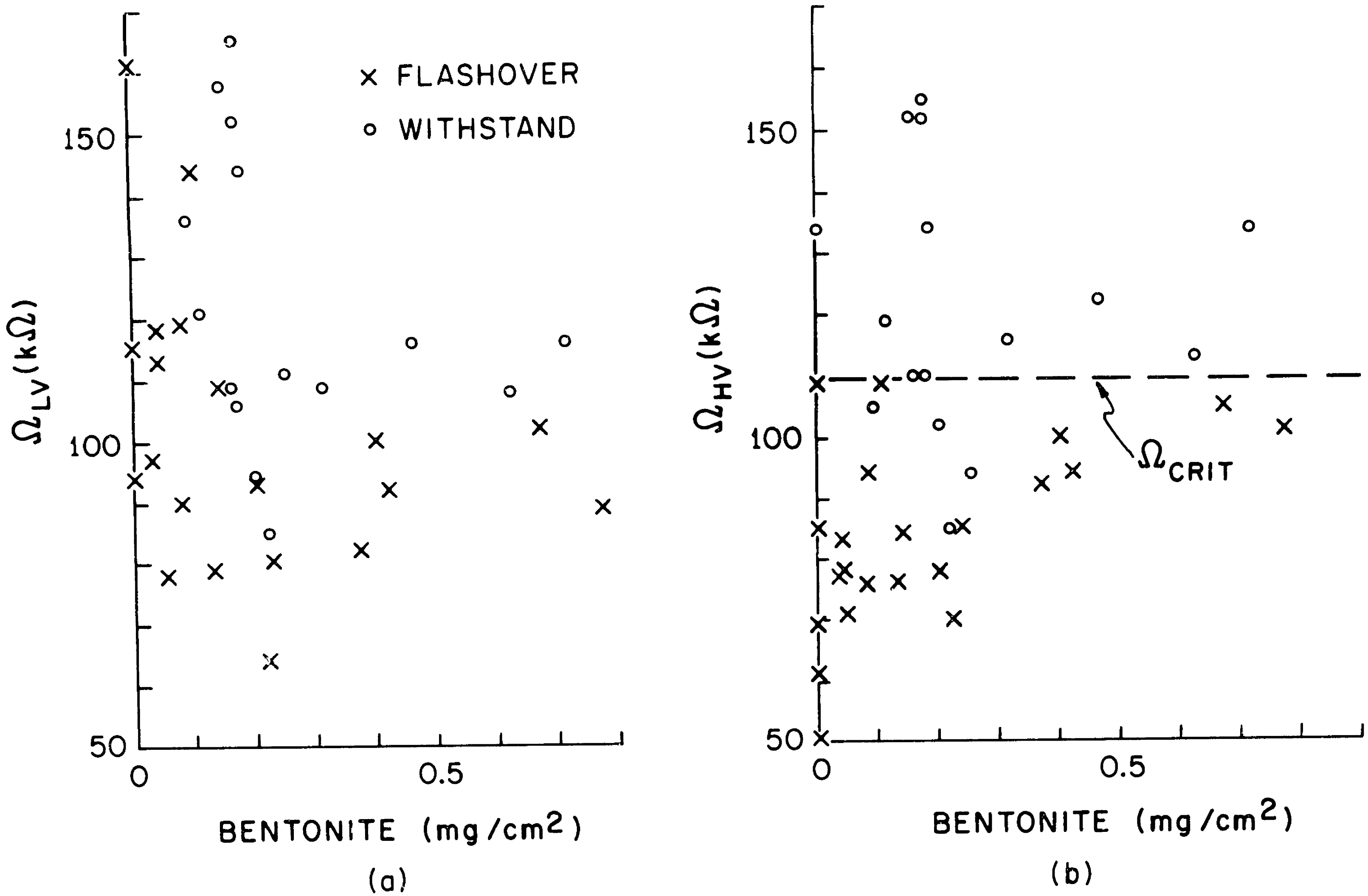
2.4 The Effect of Bentonite Level

McElroy (1969) reported that a heavier bentonite coating makes the flat plate more resistant to flashover. He carried out tests at 9.5 kV with plates that were covered either with a medium or a heavy bentonite coating (0.2 mg/cm^2 and 0.5 mg/cm^2, respectively). According to him, the critical surface resistivity for flashover at 9.5 kV was 230 kΩ per square for medium bentonite and 150 kΩ per square for heavy bentonite. Apparently the heavier bentonite required a greater amount of contamination to cause flashover. This is a startling result since the effect of the "inert" binder is normally ignored in testing and in theoretical work.

Clearly a closer investigation was called for. Accordingly, a series of 38 tests was done at 8 kV using various bentonite levels ranging from no bentonite at all to 0.77 mg/cm^2. The standard method of plate preparation and testing described in Section 2.3 was used. In each test the resistance was monitored with the 100 volt Wheatstone bridge. When the resistance had fallen to the desired level, the guard ring was removed, leaving an artificial dry zone 1/8" wide. The voltage source was set at the desired voltage which was then applied suddenly to the flat plate. The discharge current was recorded using the Visicorder set at a chart speed of 3 inches/second, which allowed the individual current peaks each half cycle to be distinguished from each other.

Since the initial voltage and current are known it is possible to calculate the resistance seen by the high voltage source, and thus the surface resistivity. By plotting the test results as in Figures 2.3a and 2.3b, it becomes apparent that the critical resistivity using the high voltage resistance value is independent of bentonite level. If the low voltage resistance is used, heavier bentonite coatings seem more resistant to flashover as McElroy found.

The reason for this discrepancy between high and low voltage resistivities can be clarified if the ratio of high voltage to low voltage resistance is plotted as a function of bentonite level for each test at 8 kV. Figure 2.4 shows that for high bentonite levels, the ratio is relatively constant at about 1.1. At low levels of bentonite the low voltage resistance is substantially higher than the high voltage value. Apparently there is poor contact between the electrodes and the water film at low bentonite levels. This would increase the low voltage resistance, but would leave the high voltage resistance unaffected since any small gaps at the electrode will be shorted out by discharging. Thus the high voltage resistance more accurately reflects the true surface film resistivity.



(a)

(b)

Fig. 2.3 Effect of bentonite level on critical resistivity using low voltage resistivity (a) and high voltage resistivity (b).

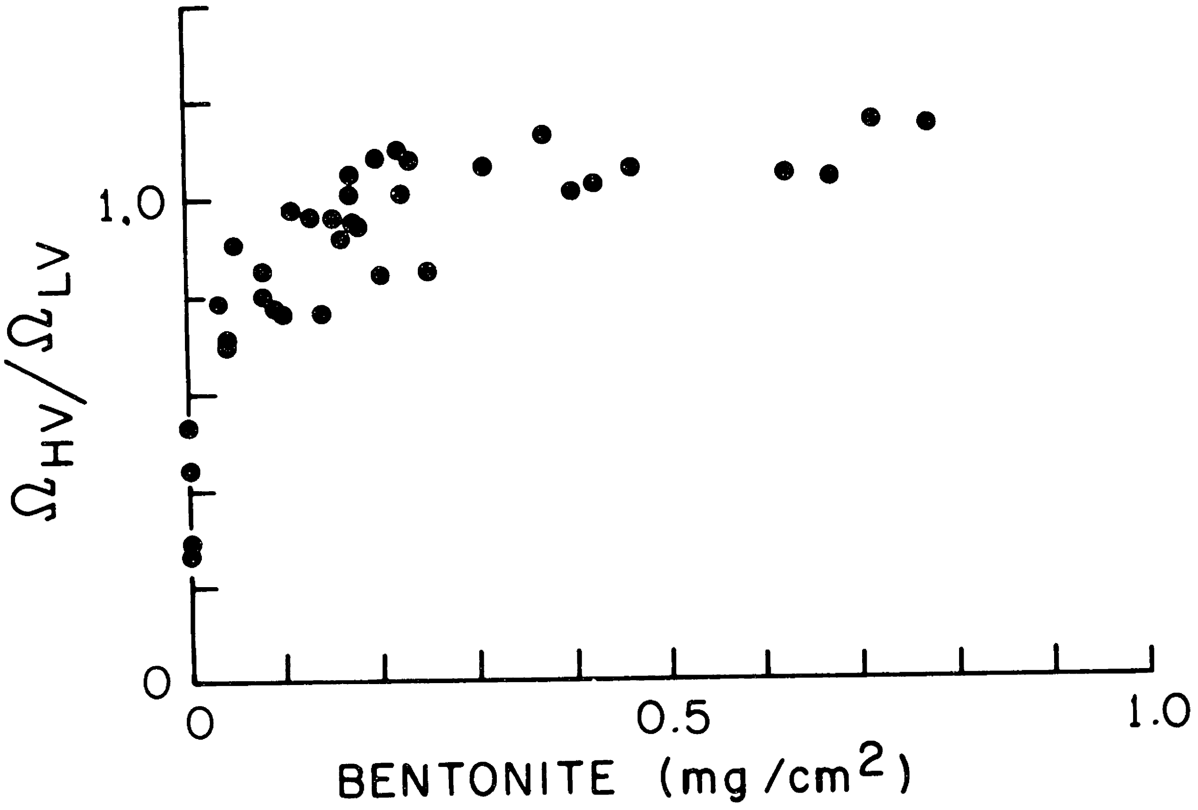


Fig. 2.4 Ratio of high to low voltage resistivity as a function of bentonite level

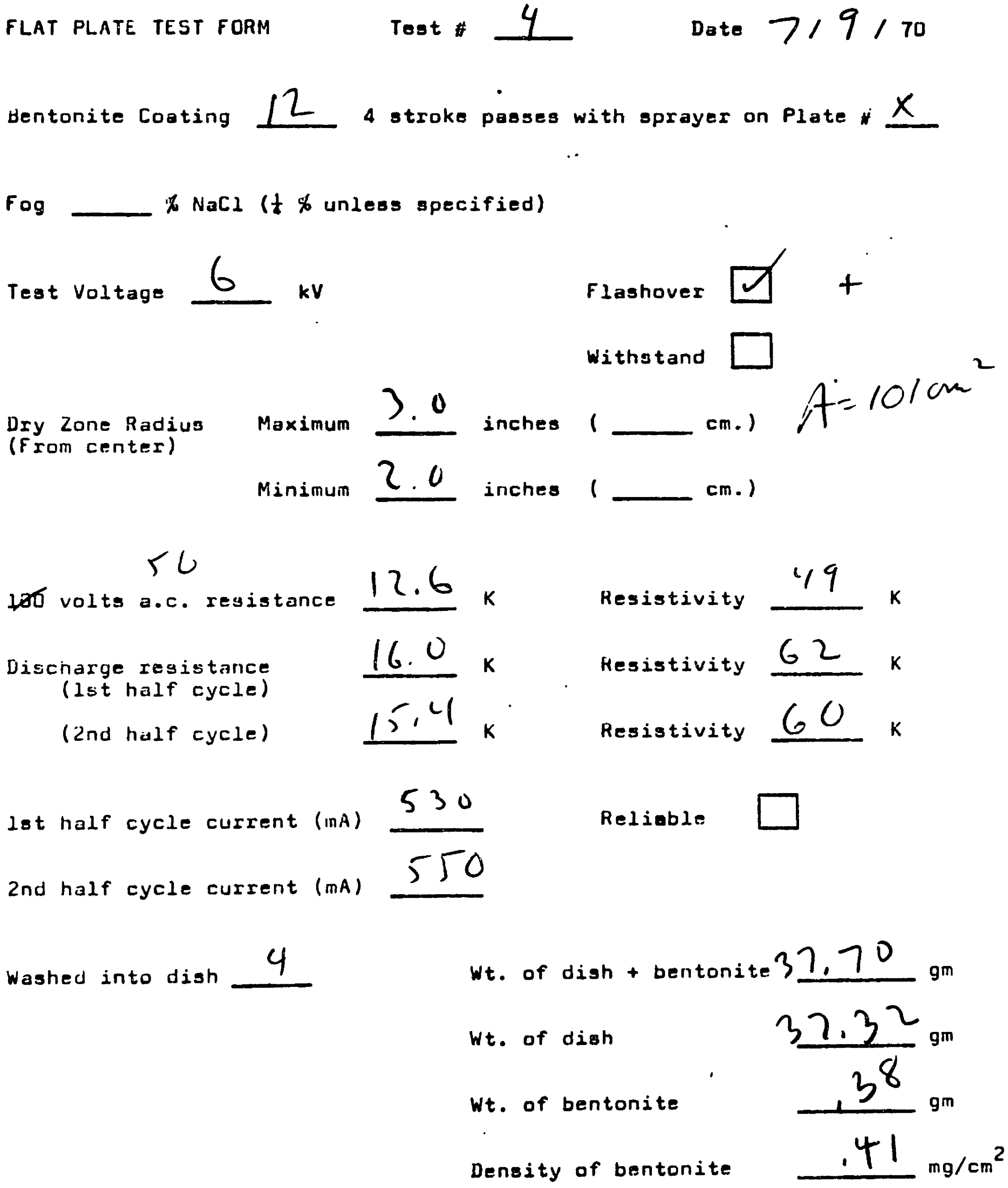
Ideally the ratio should approach unity at high bentonite levels. There are several possible reasons why the ratio is higher. In computing the resistance at high voltage, the second half cycle of the discharge record was always used, since the first half cycle did not always include the voltage maximum. In some cases it was noticed that the first current peak was 5-10% higher than the following peaks. This apparently occurs when the switch is closed near voltage maximum, discharging the capacitor across the high voltage terminals. In succeeding half cycles the normal drop of the voltage supply decreases the current. The slightly higher high voltage resistance can thus be partly accounted for as power supply drop. In addition there might be a small voltage drop due to the short initial discharges.

To sum up, the amount of bentonite present on the insulator surface has no effect on the flashover level provided the more accurate high voltage resistance is used. The detailed data on these tests may be found in Table 2.2 in Section 2.5.

2.5 Dependence of the Flashover Voltage on Surface Resistivity

Once the effect of the bentonite level had been determined, experiments could be done to find the dependence of the flashover voltage on the surface resistivity, Ω. For these tests a nominal level of 0.4 mg/cm^2 of bentonite was selected so that low and high voltage resistances would roughly agree and could serve to check each other. The standard test procedure of Section 2.3 was followed.

Figure 2.5 shows the standard form used to record the test data. The test sheet is largely self-explanatory. The dry zone radius was



FLAT PLATE TEST FORM Test # 4 Date 7/9/70

Bentonite Coating 12 4 stroke passes with sprayer on Plate # X

Fog ______ % NaCl (½ % unless specified)

Test Voltage 6 kV

Flashover ☑ +

Withstand ☐

A = 101 cm²

Dry Zone Radius (From center) Maximum 3.0 inches (______ cm.)

Minimum 2.0 inches (______ cm.)

~~100~~ 50 volts a.c. resistance 12.6 K Resistivity 49 K

Discharge resistance (1st half cycle) 16.0 K Resistivity 62 K

(2nd half cycle) 15.4 K Resistivity 60 K

1st half cycle current (mA) 530

2nd half cycle current (mA) 550

Reliable ☐

Washed into dish 4

Wt. of dish + bentonite 37.70 gm

Wt. of dish 37.32 gm

Wt. of bentonite .38 gm

Density of bentonite .41 mg/cm²

Fig. 2.5 Standard flat plate test form

recorded in order to compute the area dried by the pre-discharges (see Section 2.10). The resistivities (kΩ per square) were derived from the resistance measurements using the form factor for the flat plate.

$$\Omega = \frac{2\pi R}{\ell n \; r_o/r_i} = 3.9R = \frac{1}{f} R \qquad (2.1)$$

where: Ω = the surface resistivity
R = the measured resistance
r_o = inner radius of outer ring = 5"
r_i = radius of inner electrode = 1"
f = form factor

The blank marked "reliable" was originally intended to be checked if the low and high resistivities agreed within a certain percentage, but it was not used. The bottom 4 lines refer to the washing procedure used to find the bentonite density.

A total of 94 tests were done with the plate in the normal upright position. Of these, 38 were done at 8 kV to determine the effect of bentonite level. The remaining 56 tests were done at other voltages to find the dependence of the flashover voltage on the surface resistivity. The results are summarized in Table 2.1 and plotted in Figure 2.6. A tabulation of all 94 tests is given in Table 2.2.

Table 2.2 is written in abbreviated form and requires a word of explanation. The tests are arranged in order of voltage and high voltage resistivity. This is not the order in which the tests were carried out. No tests have been omitted from this listing. The "% NaCl" column refers to the percentage by weight of salt in the fog water reservoirs. Ω_{LV} and Ω_{HV} are the low and high voltage

Table 2.1

Summary of Flat Plate Tests

Voltage (kV)	% Salt in Fog	No. of Tests	Highest Resistivity at Which Flashover Occurred (kΩ per square)
5	1.0	4	(25.5?)
"	0.5	5	No flashovers
6	0.25	4	60
7	0.25	5	76
8	0.25	38	109
9	0.25	6	111
"	0.05	5	152
10	0.25	8	239
"	0.1	4	251
"	0.05	2	209
12	0.05	6	402
15	0.05	3	954
"	0.0	2	1020
17	0.0	2	1400

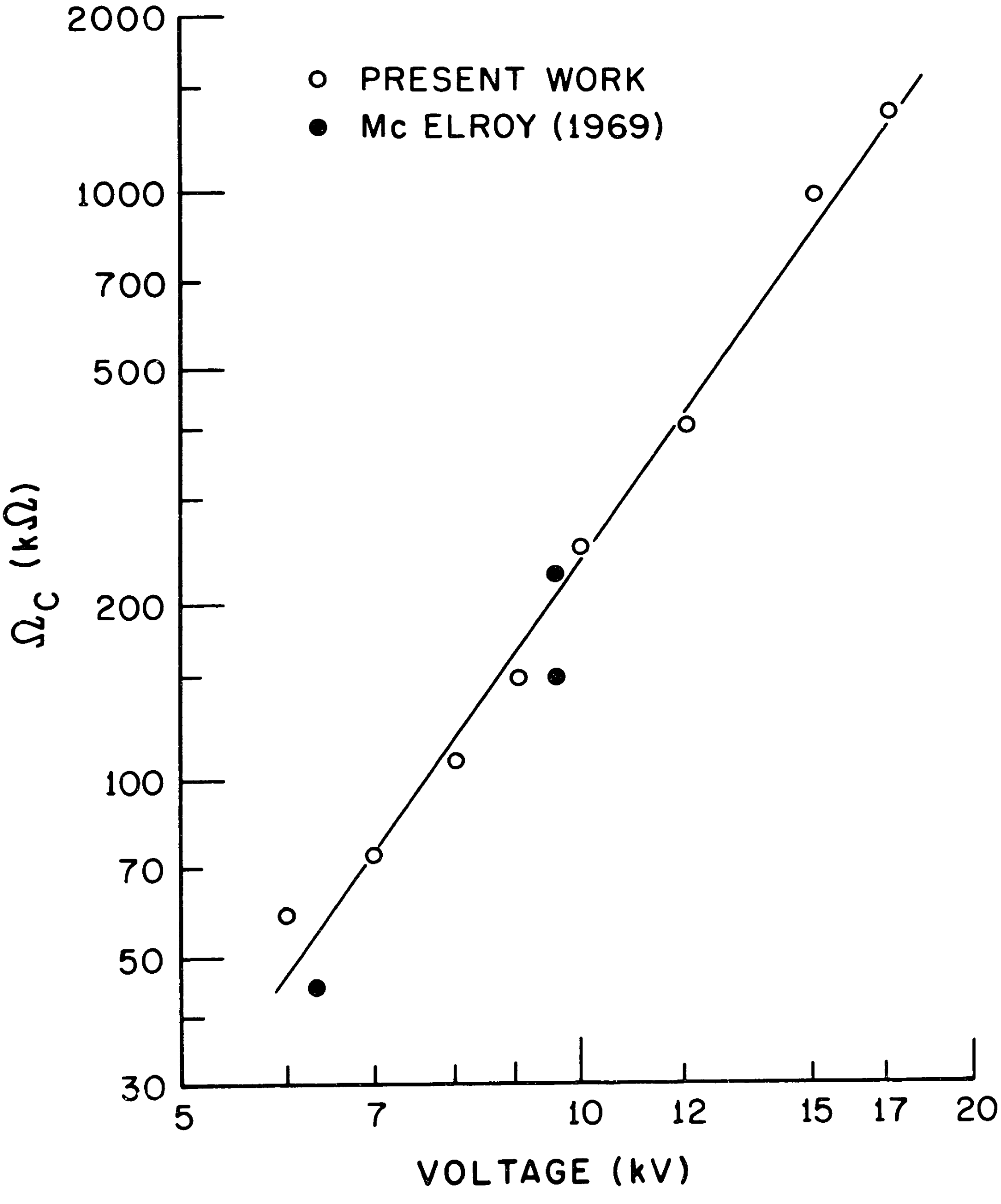


Fig. 2.6 Critical resistivity as a function of voltage.

Table 2.2

Flat Plate Test Data

Voltage (kV)	Test No.	Fog % NaCl	Ω_{LV}	Ω_{HV}	Result	Bentonite (mg/cm^2)	Dried Area (cm^2)	Time (cycles)
			kΩ per square					
5	1	1.0	10.2	25	(F?)	0.57	156	-
	2	"	11.0	25.5	(F?)	0.52	97	-
	3	"	19.5	34	W+	0.42	59	162
	4	"	22	35	W+	0.38	59	157
	5	0.5	27	39	W+	0.66	70	206
	6	"	27	41	W	0.42	76	-
	7	"	34	44	W-	0.40	44	135
	8	"	39	48	W-	0.69	139	149
	9	"	48	55	W-	0.25	64	112
6	1	0.25	50	59	F-	0.18	76	147
	2	"	49	60	F+	0.41	101	108
	3	"	57	66	W+	0.30	54	120
	4	"	63	70	W+	0.35	59	133
7	1	0.25	59	64	F-	0.21	60	71
	2	"	65	71	F+	0.68	92	107
	3	"	70	76	F+	0.86	116	128
	4	"	70	90	W+	0.13	58	140
	5	"	77	94	W-	0.47	70	101
8	1	0.25	94	50	F-	0.0	-	46
	2	"	115	61	F-	0.0	-	52
	3	"	161	69	F-	0.0	-	48
	4	"	64	70	F+	0.22	52	55
	5	"	78	71	F+	0.05	30	54
	6	"	79	76	F-	0.13	38	57
	7	"	90	76	F+	0.08	28	51
	8	"	97	77	F+	0.03	31	42
	9	"	93	78	F-	0.20	45	50
	10	"	113	78	F+	0.04	30	47
	11	"	118	83	F-	0.04	31	57
	12	"	109	84	F+	0.14	81	33
	13	"	80	85	F+	0.23	89	72
	14	"	85	85	W+	0.22	59	82
	15	"	250	85	F+	0.0	-	58
	16	"	82	92	F+	0.37	40	50
	17	"	92	94	F+	0.42	101	82
	18	"	111	94	W-	0.25	85	99
	19	"	119	94	F-	0.08	43	70
	20	"	100	100	F-	0.40	94	94

Table 2.2 (Continued)

Voltage (kV)	Test No.	Fog % NaCl	Ω_{LV} kΩ per square	Ω_{HV} kΩ per square	Result	Bentonite (mg/cm^2)	Dried Area (cm^2)	Time (cycles)
	21	"	89	101	F+	0.77	88	65
	22	"	94	102	W+	0.20	81	97
	23	"	102	105	F+	0.67	71	68
	24	"	136	105	W+	0.09	70	70
	25	"	144	109	F+	0.10	48	52
	26	"	386	109	F+	0.0	-	76
	27	"	106	110	W+	0.17	69	92
	28	"	119	110	W+	0.16	60	58
	29	"	108	113	W+	0.62	101	99
	30	"	109	116	W+	0.31	65	72
	31	"	121	119	W+	0.11	40	60
	32	"	116	122	W+	0.46	86	62
	33	"	116	139	W+	0.71	59	58
	34	"	144	134	W+	0.18	54	65
	35	"	∿2MΩ	134	W+	0.0	-	85
	36	"	152	152	W+	0.17	33	48
	37	"	158	152	W+	0.15	48	63
	38	"	165	155	W+	0.17	33	44
9	1	0.25	85	89	F-	0.33	30	33
	2	0.25	91	111	F+	0.17	58	52
	3	0.25	121	121	W+	0.15	71	62
	4	0.05	130	130	F+	0.15	24	54
	5	0.25	150	145	W+	0.12	80	62
	6	0.05	145	152	F-	0.20	64	105
	7	0.05	143	162	W+	0.66	96	84
	8	0.25	158	163	W+	0.33	60	56
	9	0.05	161	184	W+	0.65	91	92
	10	0.05	184	217	W+	0.20	54	94
	11	0.25	199	225	W+	0.53	66	50
10	1	0.1	146	167	F-	0.81	60	47
	2	0.25	160	173	F+	0.39	76	41
	3	0.25	185	179	F-	0.16	49	39
	4	0.25	189	190	F-	0.16	54	44
	5	0.1	169	197	F-	0.61	56	55
	6	0.05	173	209	F+	0.76	78	66
	7	0.25	201	213	W+	0.15	71	45
	8	0.25	186	216	F-	0.34	68	112
	9	0.1	215	230	W+	0.41	108	76
	10	0.25	202	239	F+	0.40	86	45

Table 2.2 (Continued)

Voltage (kV)	Test No.	Fog % NaCl	Ω_{LV}	Ω_{HV}	Result	Bentonite (mg/cm^2)	Dried Area (cm^2)	Time (cycles)
			kΩ per square					
	11	0.25	221	251	W+	0.53	70	48
	12	0.1	234	251	F-	0.42	74	73
	13	0.05	201	263	W+	0.76	78	60
	14	0.25	245	269	W+	0.38	66	45
12	1	0.05	269	308	F-	0.44	52	50
	2	"	250	323	F-	0.77	52	45
	3	"	290	349	W+	0.42	92	62
	4	"	332	402	F-	0.26	85	90
	5	"	351	473	W+	0.53	71	74
	6	"	351	473	W+	0.40	131*	57
15	1	0.05	694	740	F+	0.69	56	47
	2	0.05	1210	950	F+	0.66	-	43
	3	0.1	1040	1020	F+	0.99	-	39
	4	0.0	1290	1330	W	0.99	-	113
	5	0.05	1840	1660	W	0.62	-	45
17	1	0.0	1370	1400	F+	0.70	-	25
	2	"	1660	1420	W	0.70	-	95

*Voltage left on after test to watch corona resistivities (kΩ per square). "Result" indicates withstand or flashover. The polarity sign is the polarity of the center electrode on the last half cycle of discharging on withstands, or the polarity of the center electrode when flashover occurred. Thus "W+" would mean that the liquid film was acting as a cathode on the last half cycle of a withstand. Values in parentheses are uncertain due to difficulties in reading the discharge record, such as the deflection going off scale, paper running out, etc. The dried area is determined by measuring the maximum and minimum radii of the dried region immediately after the test. The area is estimated by assuming the dried area to be elliptical. The "time" column gives the time to flashover in cycles (1/60 sec.). On withstand tests it refers to the duration of the first long burst of discharge activity. Sometimes on withstands, later bursts of discharging occurred, but these were usually of low current and short duration.

It was found that the percentage of salt in the fog had a noticeable effect on flashover voltage; the greater the salt concentration, the higher the flashover voltage. That is, increasing the amount of water on the plate lowers the flashover voltage even though the resistivity is the same. This is in agreement with von Cron (1956). Apparently if the water film is too thin, any evaporation can strongly increase the resistance. To offset this effect the salt content was varied so that about 15 minutes of fog were required to reach the desired resistance. This gave a fairly heavy water film which would resist evaporation. Unfortunately above about 12 kV, there were enough soluble salts in the bentonite itself so that only a trace of water was needed to reach the critical flashover resistivity. As a consequence, the results above 12 kV should be considered approximate. At voltages below 6 kV discharge currents approach 1 A, which is near the short circuit capability of the test set (see Appendix 1). The applied voltage waveform becomes very distorted and the results are not reliable. In fact, at 5 kV it was difficult to tell if flashover had occurred either from visual observation or inspection of the discharge record.

The visible form of the discharges varied with voltage. At low voltages the discharges were yellowish and relatively thick in appearance. At higher voltages above 10 kV, the discharges were very thin bluish filaments which flicked out repeatedly from the center electrode.

The form of the Ω-vs-V curve will be discussed from a theoretical standpoint in Chapter 3.

2.6 The Effect of Replacing Bentonite with Kaolinite

Since different laboratories sometimes use different substances for the inert contaminant, the effect of substituting kaolinite for bentonite was investigated. The test procedures followed were identical to those for bentonite. Seven tests were conducted at 8 kV using 0.25% salt fog. The results of these tests are tabulated in Table 2.3. The notation used is the same as for Table 2.2.

Using the more reliable high voltage resistance, the highest resistivity at which flashover occurred is 84 kΩ per square. This compares with 109 kΩ per square for bentonite.

Two effects were observed visually which might account for the

Table 2.3

Tests at 8 kV Using Kaolinite

Test #	Ω_{LV} kΩ per square	Ω_{HV} kΩ per square	Result	Kaolinite (mg/cm^2)	Dried Area (cm^2)	Time (cycles)
1	84	76	F-	0.38	36	96
2	88	83	F(-?)	0.62	36	94
3	87	84	F-	0.45	39	103
4	88	85	W+	0.82	69	117
5	92	87	W+*	0.51	56	154
6	96	90	W+*	0.61	70	148
7	90	102	W+	0.68	53	98

*Arrested flashover occurred on tests 5 and 6.

See text.

apparently greater resistance of kaolinite to flashover. Glow discharges were observed around the entire outer ring in contrast to bentonite where this rarely occurred. The presence of discharging at the ring was confirmed by later visual inspection of the kaolinite coating which revealed disturbances characteristic of discharging. The additional voltage drop across this glow discharge would tend to make the plate more resistant to flashover. An additional drop in the discharge of about 700 volts r.m.s. would be sufficient to account for the difference in resistivities. This voltage is on the order of the total cathode and anode drop for a discharge to a moist film (Näcke, 1966), which would be the expected drop for a short discharge. The discharge was probably caused by poor contact between the water film and the outer ring. This view is reinforced by the data of Table 2.3 which shows that with one exception the discharge resistance is about 5% lower than the low voltage resistance. This contrasts to the normal behavior of bentonite coated plates which shows a high voltage resistance greater than the low voltage resistance. The kaolinite coating seemed more compact and impervious to water. This could have hindered permeation of water under the outer electrode and prevented good ohmic contact.

A second possibility is noted in Table 2.3. In at least 2 tests a thin blue discharge was seen to bridge the entire distance between the electrodes and then extinguish without triggering a follow-up power arc. The discharge record shows that this "false flashover" lasted one half cycle in test 5 and two half cycles in test 6. The peaks were off scale (greater than 0.7A) so their magnitude could not be determined. Ban (1970) discusses the manner in which a sparkover may trigger a power arc. The transient response of the voltage source may be responsible for the extinction although this effect was not as frequent for bentonite.

In summary, the difference between bentonite and kaolinite is most likely due to water permeation properties. For flat plate testing, kaolinite only complicates the theoretical analysis and was not used further. For slow fog testing of suspension insulators, the use of kaolinite might encourage discharging under the cap overhang where the insulator is somewhat shielded from the fog. This would result in apparent improvement of performance. It should be borne in mind that results cited here apply only to the particular samples of clay used here, and that other batches may behave differently.

2.7 Inverted Plate Experiments

There has been some speculation (Jolly, 1970) that the position of the discharge relative to the insulator surface may influence the flashover characteristics. For example, a discharge on the bottom side of an insulator would be pressed against the surface by buoyant forces, leading to enhanced cooling and recombination. This would increase the voltage drop across the discharge and make flashover more difficult. Since the flat plate tests had always been carried out with the discharging on the top, while suspension insulators normally scintillate on the underside, the validity of the flat plate simulation can be questioned. To deal with this objection, tests were done in which the flat plate was inverted before application of voltage.

The tests were conducted in much the normal manner. The plate was in the normal upright position while fog was applied. This is necessary since with no wind the underside of the plate remains dry. When the desired resistivity had been reached, the plate was flipped over onto four 5" long ceramic pillars which provided clearance from the supporting structure. The leads were then re-attached to the top (dry) side to avoid interference with the discharging. Voltage was then applied in the normal manner.

Four tests were done at both 6 kV and 8 kV. The results are shown in Table 2.4 in comparison with the normal upright results of Section 2.5.

Table 2.4

Highest Flashover Resistivity

	(kΩ per square)	
Voltage	Normal	Inverted
6 kV	60	54
8 kV	109	108

The resistivity given in Table 2.4 is the highest resistivity at which flashover occurred. Although only four tests were done at each voltage it seems safe to conclude that not much difference in performance results from inverting the plate. This result should, however, not be generalized indiscriminantly to all situations. For example, if the insulator in question is corrugated transversely to the creepage path, then performance might be better if the scintillations are on the bottom. This is because the buoyant forces would tend to press the discharge against the surface, causing it to follow the contours, in effect increasing the discharge length.

The test results are listed in detail in Table 2.5. Inverting the plate doesn't seem to greatly affect the time to flashover or the dried area. This perhaps suggests that the bulk of the drying is due to resistive heating before the dry zone forms. This would be unaffected by orientation. On insulators in service, however, the heating processes occur over a time span of many minutes, rather than a fraction of a second. In that case, thermal convection would be important, and an insulator designed to trap any heat release might tend to remain dryer.

2.8 Vertical Plate Experiments

In order to investigate the effect of thermal buoyant forces on the motion of the discharge, a series of tests was done in which the orientation of the plate was varied. The goal was to compare the behavior of the discharge when the discharge root moves upward, downward, or horizontally along the moist film. If buoyant forces are important for arc root motion, then the plate should flashover more easily for an upward moving arc root.

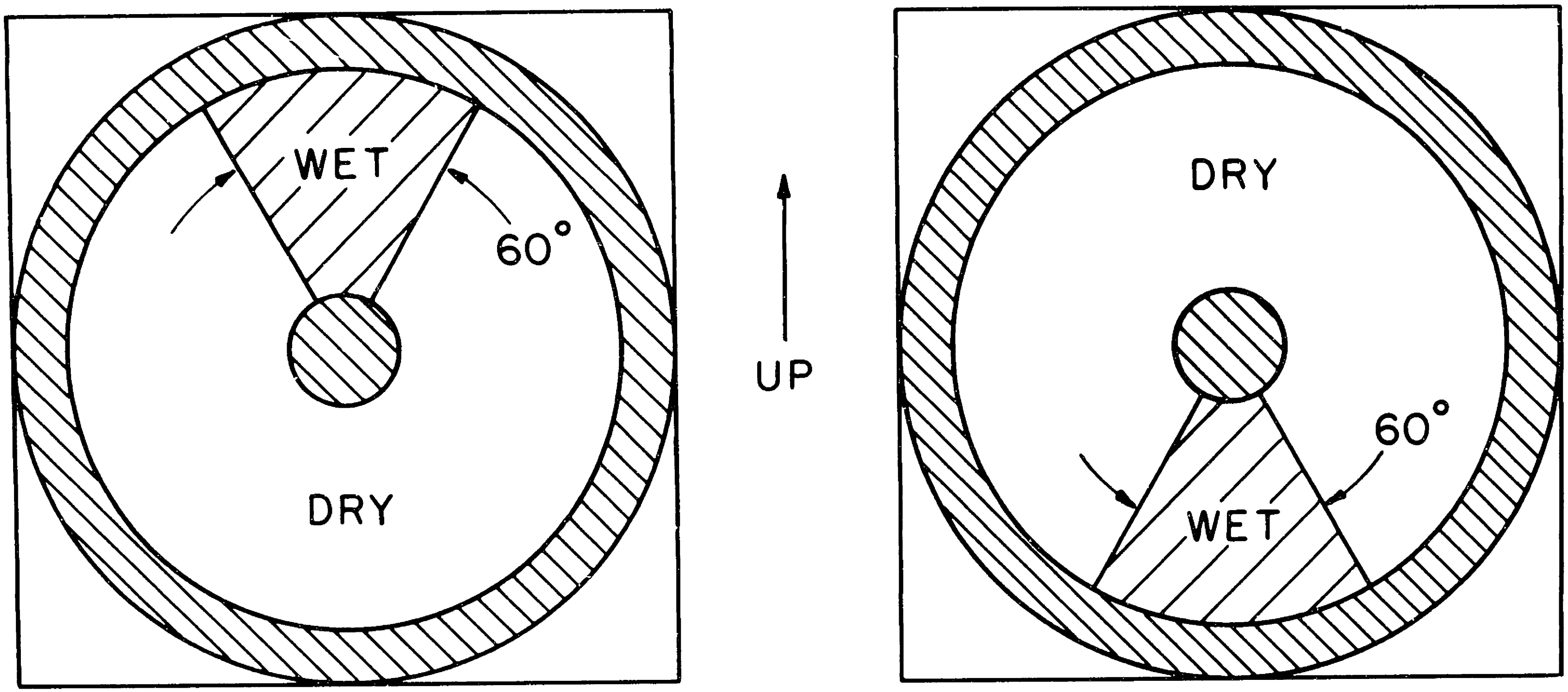
The comparison was accomplished by using a plastic shield so that the salt fog settled only on a 60° sector of the plate. After the desired resistivity was reached, the shield was removed and the plate was oriented as in Fig. 2.7. The 1/8" guard ring was not used since it interfered with the shield. Since the discharge always starts out from the center electrode, the discharge root motion can be controlled by varying the plate orientation. As a control, tests were done in which the plate was in the normal horizontal position

Table 2.5

Inverted Plate Test Data

(0.25% NaCl Fog)

Voltage (kV)	Test No.	Ω_{LV} (kΩ per square)	Ω_{HV} (kΩ per square)	Result	Bentonite (mg/cm^2)	Dried Area (cm^2)	Time (cycles)
6	1	44	54	F-	0.94	94	176
	2	49	59	W+	0.76	70	176
	3	57	63	W+	1.31	71	173
	4	60	68	W+	0.45	65	143
8	1	64	72	W+	0.47	50	147
	2	73	81	W+	0.49	41	105
	3	102	108	F+	0.39	74	66
	4	113	110	W+	0.17	64	88



(a) Discharge root moving up

(b) Discharge root moving down

Fig. 2.7 Vertical plate test arrangement.

with the contamination on the upper side.

0.25% salt fog was tried at first but the wetting time was so long that permeation distorted the shape of the wet region. 1% salt fog was found satisfactory and was used for all tests. A moderately heavy bentonite coating was used so that the draining of water when the plate was hung vertically would be negligible for resistivities of interest. The results of the tests are summarized in Table 2.6 and listed in detail in Table 2.7.

Table 2.6

Effect of Plate Orientation on Critical Resistivity

		Surface Resistivity (kΩ per square)	
Orientation	Trials	Highest F	Lowest W
Plate horizontal	14	65	74
Arc root moving up	6	74	76
Arc root moving down	6	68	76

Time limitations prevented a more extensive series of tests. However it appears that the direction of motion of the discharge root has little affect on flashover performance. In addition, time to flashover seems to be independent of the direction of motion.

It will be noted from Table 2.7 that the low and high voltage resistivities are usually in wide disagreement. This is probably due to the fact that only one sixth of the center electrode contacts the water film, making poor contact more likely. In all but one case the low voltage resistance is higher. It may also be noted that the results make more sense if the high voltage resistivity is used. This implies that, at best, low voltage resistivities should be only used

Table 2.7

Vertical Plate Test Results
(8 kV, 1% NaCl fog)

	Test No.	Ω_{LV} (kΩ per square)	Ω_{HV}	Result	Bentonite (mg/cm^2)	Time (cycles)
Plate horizontal	1	35	28	F+	0.42	8
	2	41	32	F+	0.45	10
	3	50	38	F+	0.45	11
	4	70	52	F+	0.42	21
	5	83	55	F+	0.40	24
	6	82	56	F+	0.63	17
	7	168	56	F+	0.65	18
	8	86	62	F+	0.40	31
	9	91	62	F+	0.42	20
	10	86	65	F-	0.62	26
	11	156	74	W-	0.63	36
	12	66	80	W+	0.62	30
	13	282	87	W-	0.65	32
	14	168	97	W+	0.50	30
Arc root moving up	1	94	65	F+	1.06	28
	2	83	74	F+	1.05	19
	3	126	76	W+	0.39	27
	4	126	77	W+	0.44	27
	5	120	104	W+	0.86	43
	6	246	158	W-	1.09	51
Arc root moving down	1	60	55	F+	0.86	14
	2	76	58	F+	0.44	19
	3	75	59	F+	1.09	15
	4	96	68	F+	1.06	34
	5	93	76	W+	1.05	35
	6	96	77	W-	0.39	30

as a rough indicator of contamination level.

As in the preceding section, the results here should not be generalized too far. For example, it has long been known that horizontal strings or long rods perform better than vertical ones with the same contamination. This is apparently due to thermal forces on the relatively high current partial arc which bridges one or more insulators. Flugum (1971) discusses in detail some of these effects on strings. The experiment of this section deals only with low current discharges close to the insulator surface.

2.9 Polarity and Reignition Effects

Since the processes occurring at the cathode of an electrical discharge differ markedly from those at the anode, there is every reason to suspect that polarity effects may play a significant role in the flashover process. This question is particularly important for future consideration of the direct current contamination problem.

In order to look at polarity effects, a tabulation was made for the 8 kV tests of whether the water film was acting as an anode or cathode on the last half cycle (i.e. the last half cycle on withstands, or the half cycle during which flashover occurred). This is shown in Table 2.8. The table has been divided into lighter ($\leq$ 0.2 mg/cm^2) and heavier ($>$ 0.2 mg/cm^2) bentonite levels. It can be seen that the liquid film almost always acts as the cathode at the moment of flashover for high bentonite levels. At low bentonite levels, however, flashover occurred with equal probability for both polarities. This may imply that the cathode spot becomes more mobile than the anode when sufficient bentonite is present.

On withstands, the liquid film almost always acts as the cathode on the last half cycle before extinction. Furthermore, on some withstand tests the main discharging was followed by short bursts of rectified current with the film acting as the cathode. This implies that it is more difficult to re-establish the cathode spot on the brass center electrode than on the liquid film. Thus the metal fittings on insulators may encourage the extinction of pre-discharges, thereby improving performance.

Table 2.8

Polarity Effects

Behavior of Water Film on Last Half-Cycle

(8 kV, 0.25% NaCl fog)

	Bentonite ≤ 0.2 mg/cm^2	
	Cathode	Anode
Flashovers	8	7
Withstands	10	0
	Bentonite > 0.2 mg/cm^2	
	Cathode	Anode
Flashovers	6	1
Withstands	5	1

There has been speculation (Claverie, 1970) that reignition effects may be important in the flashover process. In alternating current discharges, extinction occurs as the applied voltage approaches zero and there is not enough energy input to maintain ionization in the discharge channel. After voltage zero, the voltage then increases in the opposite direction until it is high enough to break down the residual channel of ionized gas. The arc then reignites. The behavior of the current is shown in Fig. 2.8.

In order to look at the behavior of the reignition angle, two high speed (60"/second) discharge current records were taken, one flashover and one withstand (8 kV tests #9 and #18). The Visicorder was started automatically by a remote current sensing circuit to conserve paper (see Appendix 1 for circuit diagram). Due to inertia it took about 10 cycles (1/6 sec.) before the paper speed was sufficient to resolve angles.

In the case of the flashover, the reignition angle varied from about 15° at 10 cycles to about 24° just before flashover. Flashover itself occurred at about 75° after current zero. There seemed to be little effect of polarity on the reignition angle.

In the withstand test, the angle varied from 12° at 10 cycles to about 36° at 95 cycles. The angle then increased rapidly to 72° for the (center electrode) positive half cycle and 99° for the negative half cycle after which extinction occurred. There were two subsequent short bursts of discharging whose reignition angles fluctuated between 40° and 70°. As usually happens in cases like this, this was the one anomolous test in which the water film acted as the anode on the last half cycle of the main discharge burst. However for the two succeeding short bursts, it acted as the cathode on the last half cycle.

2.10 Time to Flashover and Area of the Dried Region

In an attempt to shed some light on the flashover process, the

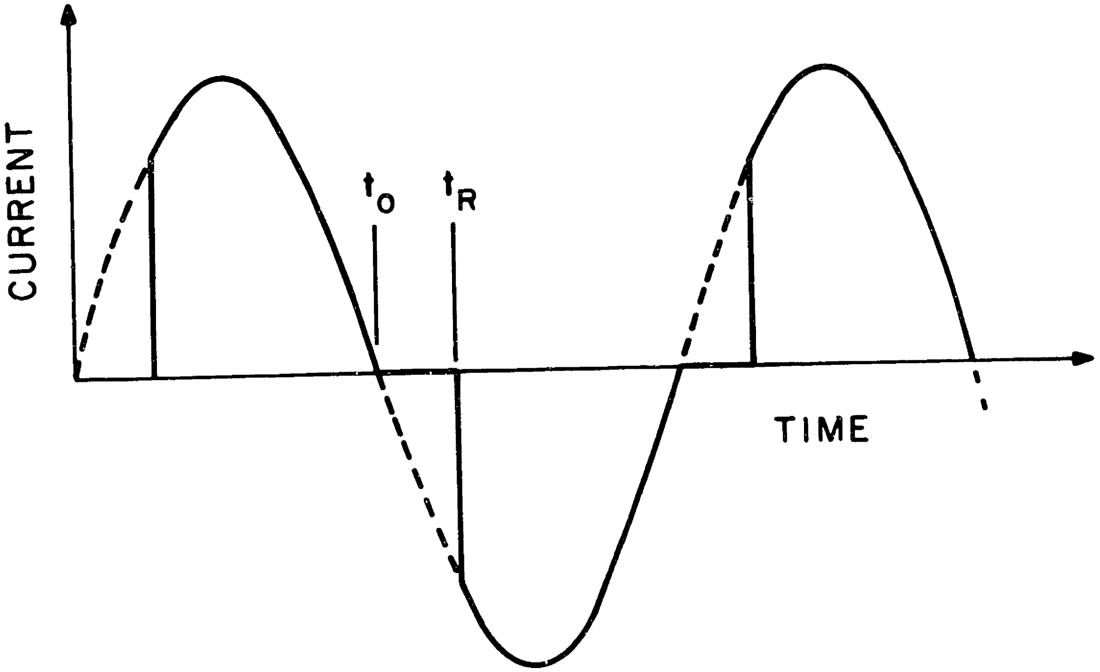


Fig. 2.8 Schematic representation of reignition angle. Current (and voltage) zero occurs at time t_o. The discharge channel then cools rapidly and becomes conducting only when sufficient voltage is re-applied at t_R. The reignition angle is defined as $360^\circ (t_R - t_o)/T$ where T is the period of the applied voltage.

time which elapsed between the application of voltage and either flashover or the cessation of discharging was studied. To simplify things as much as possible, only the data at 8 kV was analyzed. The only controlled variable is then the surface resistivity. A glance at Table 2.2 shows that there seems to be little if any dependence of the duration of discharging on resistivity. Since the times involved are on the order of one second, thermal processes probably play a role. This is confirmed to some extent if the area dried is plotted as a function of the duration of the discharging. Figure 2.9 clearly indicates the relationship. The intercept on the time axis suggests that the heat is dissipated over a region around the center electrode rather than right at the edge of the dry zone. The dry region, in other words, is formed by a thinning of the water film rather than by a "rollback" starting at the center electrode.

Of course, this still doesn't answer the question of how much drying must take place for flashover to occur.

2.11 Wire Electrode Discharge Experiments

In a further effort at simplification a number of experiments were carried out in which a discharge burning in series with a fixed resistance and a constant voltage source was elongated until it extinguished. The purpose was to simulate the extinction of discharges on the flat plate and the standard suspension insulator where the resistance in series with the arc is relatively independent of arc length. One method of elongating the arc is to draw the electrodes apart electromechanically. However in the present study the elongation

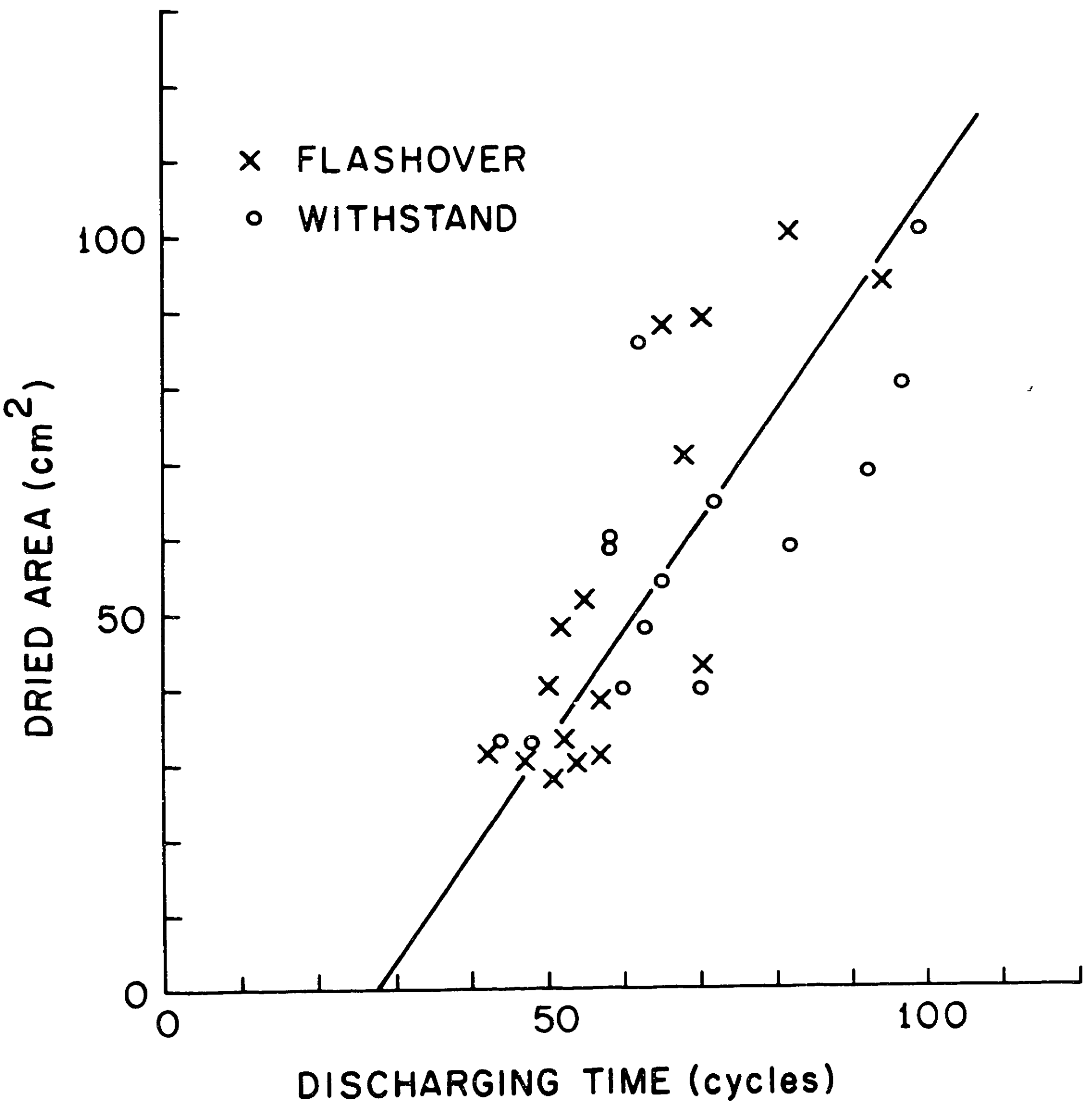


Fig. 2.9 Dried area as a function of the duration of discharging.

was accomplished by making one electrode out of fine copper wire which would melt back due to the heat of the discharge until extinction occurred. The gap could then be measured and the effects of voltage, series resistance and electrode material studied.

A preliminary series was done to find the experimental arrangement giving the most repeatable data. A voltage of 16 kV r.m.s. and a 100 kΩ series resistance were used since they gave extinction lengths on the order of the pin to edge distance of suspension insulators. A vertical arrangement was selected with #30 A.W.G. copper wire as the upper electrode and #13 bare copper wire as the lower one. Replacing the heavier #13 wire with pencil lead or 1/16" aluminum rod made no significant change in extinction length. Wire ranging from #20 to #33 was tried for the upper electrode. The finer wire was difficult to handle while thicker wire resulted in longer burning times, making random extinction more likely. The burning time was proportional to the area of the wire and was independent of whether the fine wire was on the top or the bottom. A rough calculation revealed that the power required to melt the copper corresponded to a voltage drop of several hundred volts. This is on the order of the 375 volt cathode fall for copper electrodes in air and suggests that at this current ($\sim$160 mA r.m.s.) the discharge was a glow discharge rather than an arc which has a cathode fall of 10 volts or so (von Engel, 1965). The electrodes had to be very close to vertical since otherwise the discharge would flap around and go out prematurely.

A series of 56 tests was then done using resistances of 20,000 to 500,000 ohms and voltages of 8 kV to 24 kV. The maximum extinction length was found to be closely approximated by

$$\ell_{max} = 3.6 \frac{V^{1.7}}{R^{0.7}} \qquad (2.2)$$

where ℓ_{max} is in centimeters and

V = the applied voltage in kV r.m.s.

R = the series resistance in kΩ

As will be explained in Chapter 3, this is consistent with an arc characteristic of

$$E = 0.16\ I^{-0.7} \qquad (2.3)$$

where

E = the longitudinal arc field in kV/cm

I = the instantaneous arc current in amperes

In reality the voltage drop along the arc is probably somewhat less than given by Eq. 2.3 because of random extinctions. In addition the discharge characteristic on an actual insulator may be affected by orientation and the presence of steam. Thus the copper wire tests may not be an appropriate simulation of discharges on contaminanted surfaces and were not continued further.

2.12 Summary

A number of interesting things were learned as a result of the flat plate experiments:

1) Contrary to McElroy's findings (1969) there was no observable dependence of the critical resistivity on the bentonite level. An apparent dependence results if the less reliable low voltage (50 volts)

resistance is used. This is because for low bentonite levels the water film makes poor contact with the electrodes. At higher bentonite levels the bentonite acts like blotting paper, and breaks up the surface tension of the film, allowing better ohmic contact to be made. The high voltage resistivity determined by the discharge current record was only slightly affected by poor electrode-film contact since any small gaps are immediately bridged by discharges or closed by the electric forces attracting the water film.

2) The resistivity necessary for flashover exhibited a power law dependence on voltage, i.e., a straight line can fit the data on a log-log plot.

3) Lower fog salt percentages lead to lower flashover voltages for the same initial surface resistivity. This is attributed to the quicker evaporation of the more concentrated salt solutions at higher fog salt percentages.

4) When bentonite was replaced with kaolinite a lower resistivity was needed for flashover. This could be due to discharging observed around the outer ring electrode. The discharging may have been caused by the poor permeation of water through the kaolinite which prevented good ohmic contact with the outer electrode.

5) It makes little or no difference whether the discharging is on the upper or lower surface of the plate.

6) For typical discharge conditions it made no difference in the critical resistivity whether the discharge root was moving upward, downward, or horizontally. Thus, at least for the conditions

studied, thermal buoyant forces appear to be unnecessary for discharge root motion.

7) For high bentonite levels flashover at 8 kV usually occurred when the film was acting as the cathode. For low bentonite levels flashover occurred with equal probability for both polarities.

8) In two tests where high speed oscillographs were taken of the discharge current the reignition angle could be measured. In the flashover test the angle increased with time to about 24° just before flashover. Flashover itself occurred at an angle of 75°, i.e., 15° before the voltage maximum. In the withstand test the angle increased to 72° and 99° on the last two half cycles. The large angles involved suggest that reignition may play a role but its importance can not yet be estimated.

9) Time to flashover was related to the dried area measured after the test. This suggests but doesn't prove that thermal drying effects control the time to flashover.

10) Wire electrode discharge experiments were done, but their relation to contamination flashover is not apparent.

CHAPTER 3

DISCHARGE THEORY

3.1 Introduction

Contamination flashover has been studied intensively now for over forty years. During this time much has been learned, and one would expect that there would be little of importance left to study. Test procedures have been developed, new insulators introduced, and a great deal of operating experience has been obtained. Nevertheless there is one important detail which has successfully resisted all efforts at understanding. No one yet knows what physical processes are involved in the movement of a discharge across a moist surface. This is not to say that there is any lack of theories, since in fact there is a surplus of theories, each purporting to represent the flashover process. Furthermore all of these theories have been shown by their proponents to agree with the data from flashover tests. This is quite remarkable since some of these theories are based on assumptions flatly contradicting those of other theories.

In this chapter some of the theoretical aspects of contamination flashover will be discussed. The leading theories will be examined, and some will be found unsatisfactory. Several additional mechanisms which may play a role will be suggested. The flat plate data of Chapter 2 will be used to help discriminate between the possible mechanisms.

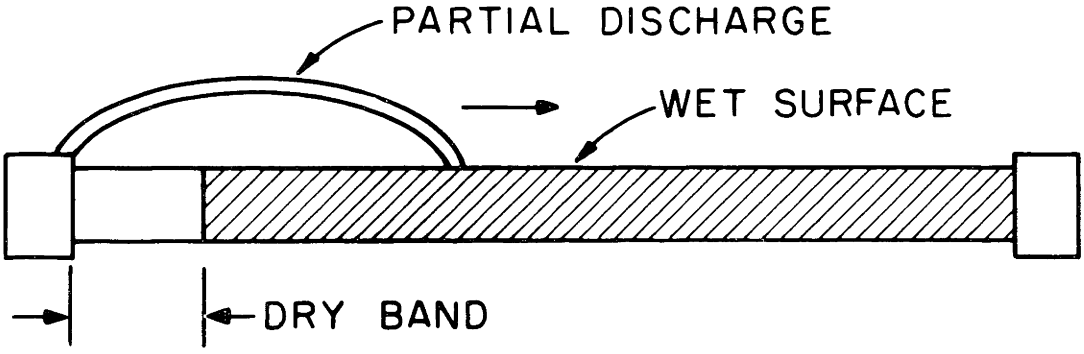
In order to avoid confusion the following consistent system of units will be used throughout this chapter unless otherwise specified: voltage (kV), current (A), resistance (kΩ), distance (cm), and electric field strength (kV/cm).

3.2 The Extinction Theory of Obenaus

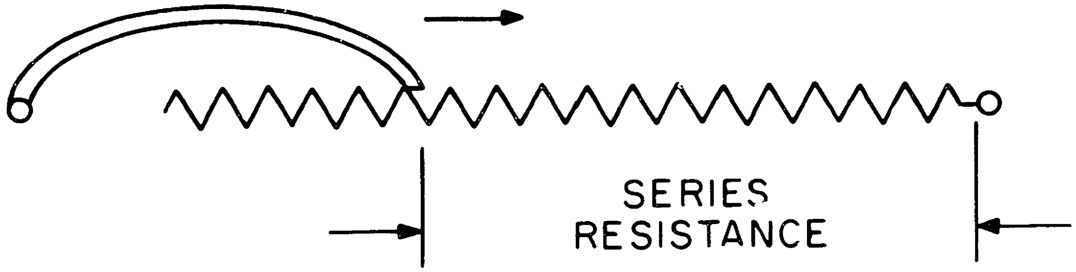
In 1958 Prof. Obenaus, Director of the Institute für Hochspannungtechnik at Dresden, proposed the first quantitative theory of flashover. However in his paper (Obenaus, 1958) he merely outlined the computational steps that would be involved. His method was carried to completion by an associate (Neumärker, 1959) who was able to derive an expression relating the surface resistivity to the critical flashover voltage. Later workers (Böhme, 1965; Böhme and Obenaus, 1966) were able to obtain good agreement between the theory and actual insulator test results.

The theory models the flashover process as a discharge in series with a resistance, the discharge representing the partial flashover of the insulator surface and the resistance representing the unbridged portion of the insulator. Figure 3.1 shows the modeling concept. Obenaus then assumes that flashover will occur if the discharge is able to bridge the insulator without extinguishing.

In the current range of interest, about 20 to 1000 mA, the discharge should have a falling voltage characteristic. This corresponds to the curve labeled V_{arc} in Fig. 3.2. The voltage drop across the resistance, V_{res}, is a linear function of current. Since these two elements are in series, the characteristic seen at the insulator terminals is obtained by adding voltages, giving the solid line of Fig. 3.2. It can be seen that no current solutions exist below the



(a) Insulator



(b) Obenaus' Model

Fig. 3.1 The modeling concept of Obenaus.

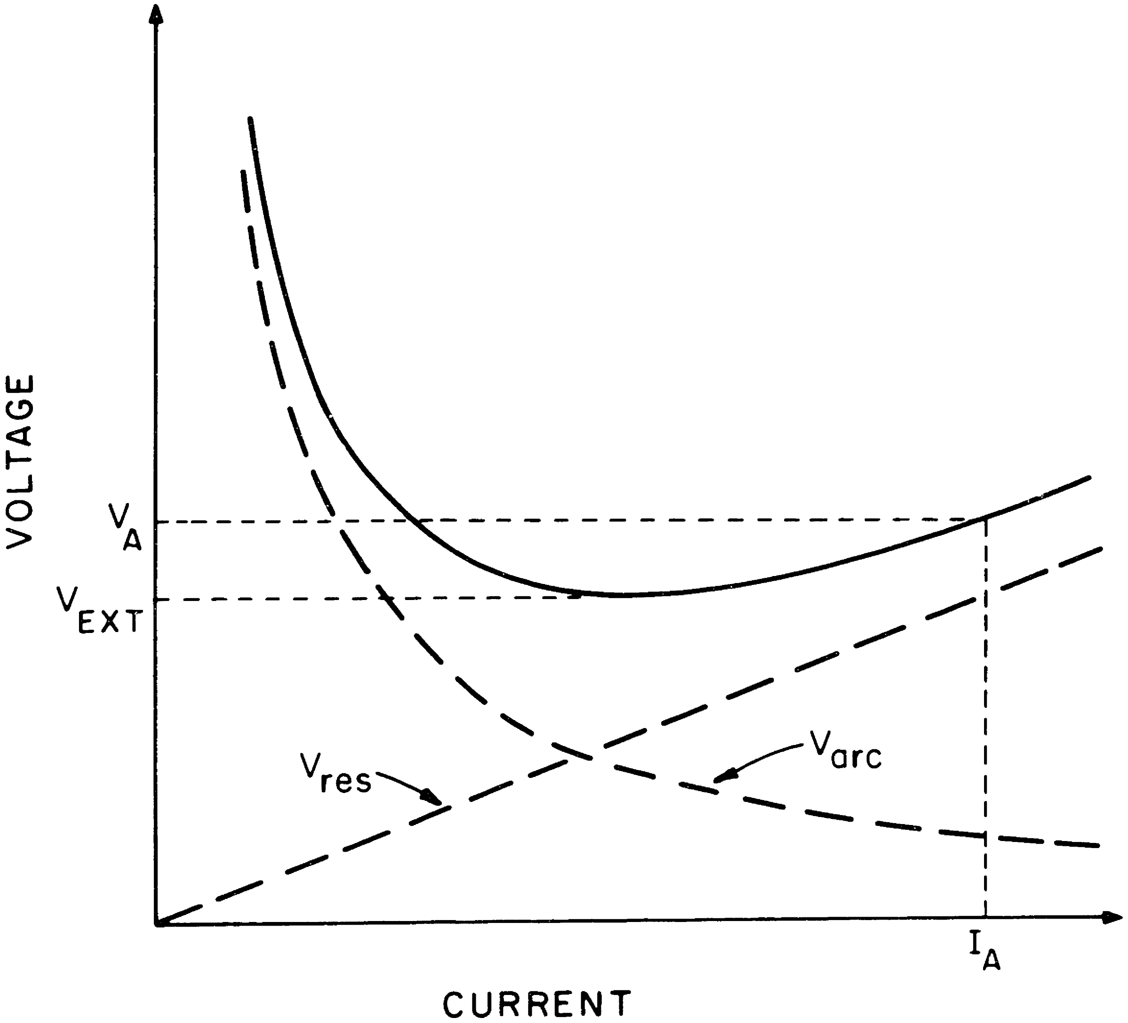


Fig. 3.2 Voltage current characteristic of a discharge in series with a resistance.

extinction voltage, V_{ext}. In practice the discharge characteristic approaches the origin at very low currents, and there is always a small but negligible current flow at voltages below V_{ext}. At voltages above V_{ext} the operating point will be on the positively sloping portion of the curve since the negative resistance region is unstable. Thus at voltage V_a, as shown in Fig. 3.2, a current I_a will flow. The characteristics shown would apply only for a single value of the discharge length. As the discharge lengthens, its voltage drop for a given current will increase, while the resistance in series will decrease.

The role of the series resistance in preventing flashover is clear. If the resistance is high the discharge current will be choked off, causing a high voltage drop across the discharge. If the voltage drop is high enough the discharge will be unable to bridge the insulator, and flashover can not occur.

As mentioned, the calculations were first done by Neumärker. However his method, although correct, is not very general and is also somewhat difficult to follow. A simplified calculation is presented below which can be applied to both the flat plate and to long rod insulators. The derivation for the long rod case has also been done correctly by Alston and Zoledziowski (1963) who were unaware that Neumärker had already done it four years earlier.

The starting point is to approximate the discharge characteristic as

$$V_{arc} = A\, x_{arc}\, I^{-n} \tag{3.1}$$

where x_{arc} is the discharge length, I is the discharge current, and A and n are constants. The cathode drop has been ignored and the discharge voltage is assumed proportional to the discharge length. These approximations will be examined later in the light of experimental data. The derivation presented here will strictly apply only to direct current. The transition to alternating current will be made by assuming that the most critical condition occurs at voltage maximum. Thus interpreting V and I as the peak a.c. quantities should give the a.c. flashover conditions.

The series resistance will be modeled by the expression

$$R = \Omega B(\ell - x_{arc})^m \tag{3.2}$$

where Ω is the surface resistivity, B and m are geometrical constants depending on the insulator, and ℓ is the total distance the discharge must extend to bridge the insulator. For the long rod insulator $m = 1$, and for geometries such as the flat plate insulator where the resistivity is relatively independent of the position of the discharge root, $m = 0$. In reality the series resistance is also a function of current since the discharge root radius varies with current. However, as will be seen, this dependence can often be ignored.

The total voltage V applied to the insulator must equal the sum of the discharge and resistive drops.

$$V = V_{arc} + V_{res} = Ax_{arc}I^{-n} + \Omega B(\ell - x_{arc})^m\, I \tag{3.3}$$

As is evident from Fig. 3.1 the minimum voltage which can sustain a discharge occurs where the derivative of the total voltage with respect to current equals zero. Thus

$$\frac{\partial V}{\partial I} = 0 = - nAx_{arc}I^{-(n+1)} + \Omega B(\ell - x_{arc})^m \tag{3.4}$$

Solving for the current I,

$$I = \left[\frac{nAx_{arc}}{\partial B(\ell - x_{arc})^m} \right]^{\frac{1}{n+1}} \tag{3.5}$$

Substituting (3.5) into (3.3)

$$V = (n+1)(Ax_{arc})^{\frac{1}{n+1}} \left[\frac{\Omega B(\ell - x_{arc})^m}{n} \right]^{\frac{n}{n+1}} \tag{3.6}$$

Equation 3.6 gives the minimum voltage necessary to maintain a discharge of any length x_{arc} between 0 and ℓ. In order for flashover to be possible, the supply voltage must exceed the minimum sustaining voltage for all values of x_{arc}. Thus the minimum voltage necessary for flashover can be obtained by finding the maximum of (3.6) with respect to x_{arc}. Setting the derivative equal to zero,

$$\frac{\partial V}{\partial x_{arc}} = 0 = \frac{1}{n+1} \frac{V}{x_{arc}} - \frac{nm}{n+1} \frac{V}{\ell - x_{arc}} \tag{3.7}$$

or

$$x_{crit} = \frac{\ell}{mn + 1} \tag{3.8}$$

x_{crit} is the discharge length for which the sustaining voltage is a maximum. Since the applied voltage must equal or exceed this value for flashover to occur, the minimum voltage for flashover is obtained by substituting (3.8) into (3.6).

$$V_{crit} = \left[\frac{(mn)^{mn}(n+1)^{n+1}}{n^n\ (mn + 1)^{mn+1}}\ A\ (\Omega B)^n\ \ell^{mn+1} \right]^{\frac{1}{n+1}} \tag{3.9}$$

This can be rewritten to give the critical resistivity in terms of the applied voltage.

$$\Omega_{crit} = \frac{V^{\frac{n+1}{n}}}{B} \left[\frac{(mn)^{mn}(n+1)^{n+1}}{n^{n}\ (mn + 1)^{mn+1}} A\ell^{\ mn+1} \right]^{-\frac{1}{n}} \tag{3.10}$$

The current at the critical distance and voltage is

$$I_{crit} = \left[\frac{nA}{\Omega B} \ \frac{1}{(mn)^{m}} \ \left(\frac{\ell}{mn+1}\right)^{1-m} \right]^{\frac{1}{n+1}} \tag{3.11}$$

These equations can be applied to two cases of interest, the flat plate insulator and the long rod insulator. For the flat plate, the resistance seen by the discharge turns out to be almost independent of current and position. In this case, $m = 0$. For the long rod the resistance is a linear function of distance along the insulator and $m = 1$. By substituting these values of m into (3.8), (3.9), (3.10), and (3.11) a list of the critical flashover quantities can be constructed as shown in Table 3.1.

A few words of interpretation may be helpful. The critical discharge length is that discharge length where the sustaining voltage is a maximum. For the ideal flat plate the maximum voltage is required at the maximum possible discharge length as expected. However for the long rod the maximum voltage is required for a discharge which only bridges part of the insulator. It follows that if a discharge bridges a fraction $1/(n+1)$ of a long rod, then flashover of the rest is possible.

Table 3.1

Critical Discharge Quantities

	Idealized Flat Plate (m = 0)	Idealized Long Rod (m = 1)
x_{crit}	ℓ	$\ell/(n+1)$
V_{crit}	$(n+1)\left[A\ell\left(\frac{\Omega B}{n}\right)^{n}\right]^{\frac{1}{n+1}}$	$A^{\frac{1}{n+1}}\,\ell(\Omega B)^{\frac{n}{n+1}}$
Ω_{crit}	$\frac{n}{B(A\ell)^{1/n}}\left[\frac{V}{n+1}\right]^{\frac{n+1}{n}}$	$\frac{1}{BA^{1/n}}\left(\frac{V}{\ell}\right)^{\frac{n+1}{n}}$
I_{crit}	$\left[\frac{nA\ell}{\Omega B}\right]^{\frac{1}{n+1}}$	$\left[\frac{A}{\Omega B}\right]^{\frac{1}{n+1}}$

The critical voltage is the minimum voltage for which flashover is possible. It is important to realize that flashover does not necessarily occur if the applied voltage exceeds the critical voltage. Thus the condition that V exceed V_{crit} is a necessary but not sufficient criterion for flashover. The only definite statement that can be made is that flashover can not occur of $V < V_{crit}$, since in that case the discharge will extinguish. A similar remark can be made about the critical resistivity. If $\Omega > \Omega_{crit}$ flashover definitely can not occur.

The critical currents given have quite different interpretations for the two geometries. For the long rod this is the minimum current for a discharge length of x_{crit} necessary for flashover. It also turns out to be the minimum current flow through the insulator for $x_{arc} = 0$ which will lead to flashover. Thus in a wet contaminant test of a long rod insulator the initial current must exceed this critical current for flashover to occur.

For the flat plate I_{crit} is the minimum current that can flow on an insulator which flashes over. Thus on a flashover test, no current peak should ever fall below I_{crit}.

The above analysis is highly idealized and neglects the effects of drying and heating of the moist film for example. There are however subsidiary issues which do not affect the essence of the theory.

Obenaus' extinction criterion, briefly summed up, is that a discharge must be able to exist for all discharge lengths in order for flashover to occur. Nothing is said of what physical processes are involved in the movement of the discharge across the surface. Several alternatives to Obenaus' approach will be examined in the next section.

3.3 Other Previous Theoretical Approaches

Several alternatives to the extinction model of Obenaus have been proposed. Some of these proposals deserve serious consideration, but others appear to be based on fuzzy physical reasoning in which irrelevant general principles are invoked without any regard for the actual facts of the matter.

One approach is that of Hampton (1964) who based his theory on a very interesting experiment in which he used a water jet to simulate a contaminated long rod insulator. He concluded that flashover could be treated as a stability problem. He claimed that an unstable situation exists if a current increase occurs when the discharge root is displaced in the direction of flashover. As the discharge lengthens, the current will increase, and the discharge root will move rapidly across the surface. He reasoned from this that if the voltage gradient along the discharge ever falls below the gradient along the resistive column, then flashover will occur. He was able to obtain good agreement between this model and his own flashover data on the water column. Hampton's criterion may have been anticipated by Shkuropat (1957). However it appears to have no physical basis.

Hesketh (1967) was later able to prove mathematically that Hampton's two criteria of voltage gradient and current increase are identical only in the case of a long rod insulator.

Billings and Wilkins (1966) considered the problem of the flashover of a long rod insulator with a semiconductive glaze. They used both the criterion of Obenaus and that of Hampton and obtained identical results. The reason for this agreement between two seemingly different theories can be found by using the expression of Hesketh (1967) for the change in current as the discharge length varies. Using the critical current of Obenaus' method it is found that $dI/dx_{arc} = 0$ for a discharge of zero length. Thus for the long rod the two methods automatically agree. This is not so for the flat plate type. In this case the current always decreases for an increase in discharge length. Thus according to the criterion of Hampton the flat plate insulator could never flash over, which unfortunately is not true.

Wilkins (1969) apparently did not realize that the criterion of Hampton could be applied only to the long rod. He says that flashover will occur if either dP/dx_{arc} or dI/dx_{arc} is greater than zero, where P is the power taken from the supply. Using this criterion he makes the following statement, "It is easy to show that a discharge burning in series with a fixed resistance between two irregularly shaped electrodes will always move to a position where its length is a minimum." (Zoledziowski, 1968, discussion). To test this statement the author personally constructed a "Jacob's ladder" which is just a horn gap in series with a resistor. When voltage was applied, the discharges which formed were wafted gently upward by the thermal buoyant forces, elongating as expected.

Wilkins' statement may however be modified to apply only when no external forces are acting. He seems to have done this in a later publication (Wilkins, 1969) where he says, "A number of different experiments have been devised using irregularly shaped water electrodes, and it has been found that the discharge always moves to a position where its length is a minimum. For these experiments, substantial water electrodes were used, so that discharge movement caused by "drying-out" of the electrodes was impossible, and the electrodes were designed in such a way that electrodynamic and convective forces could be discounted." However there is no need to invoke a questionable stability criterion to explain this effect. It is sounder to simply look at the physics involved. Steenbeck (1937) showed that low current arcs appear to possess a longitudinal traction, that is, they behave somewhat like feeble rubber bands. Steenbeck tentatively attributed this longitudinal traction to Debye-Hückel effects. Such a traction would naturally tend to pull a discharge toward the narrowest gap between electrodes in the absence of any competing forces.

Billings and Wilkins (1966) invoke what appears to be some sort of general physical principle when they say, "Any free physical system will try to attain a state where it is expending minimum energy (or power)." The applicability of this type of principle to contamination flashover is not apparent.

Furthermore Zoledziowski (1968) states that he has observed discharge root movement below the voltage where dI/dx_{arc} becomes positive. Thus the criterion of Hampton would seem to apply only to the original geometry of his experiment, and not to all insulator shapes as assumed by Wilkins.

Näcke (1966) has also proposed a criterion for flashover which is similar in concept to that of Hampton. However he deals with voltage rather than current or power. He considers the change of total voltage for a displacement of the discharge root at constant current, the voltage change being given as,

$$dV = \frac{\partial V_{arc}}{\partial x_{arc}} dx_{arc} + I_{arc} \frac{\partial R}{\partial x_{res}} dx_{res} \tag{3.12}$$

where x_{res} is the length of unbridged resistance. He then says that if $dV < 0$ the discharge will be unstable and flashover will occur. He referes to the incremental voltage change, dV, as an independent voltage source which can "force a non-stationary field migration." How this migration comes about is not specified. Furthermore it is not clear why a constraint of constant current is imposed, rather than the actual constraint of constant voltage. Naturally, as with all other flashover theories, the agreement with the data is excellent.

Claverie (1970) and Rizk (1971a, b) have both developed theories of flashover directly applicable to alternating current. They do this by considering the effects of the reignition phenomena which occur every half cycle. Once again, although these two theories differ from each other, and from all other theories, both are in perfect agreement with the data. The only way to evaluate the merits of these reignition theories would be to compare a.c. and d.c. test results. Unfortunately at present the available data on direct current flashover is too sketchy for any firm conclusions to be drawn.

McElroy (1969) attempted to apply a modified form of the theory of Obenaus to flat plate flashover. Rather than deducing the value of m in Eq. 3.2 from theory, he tried to evaluate it from discharge current data and obtained a value of 2.7 (McElroy, 1969). Later (Woodson and McElroy, 1970a) he decided that m was really 1.4. This particular approach was criticized in the discussion by Remde (Woodson and McElroy, 1970b).

3.4 The Physical Basis of Flashover

The flashover mechanisms discussed in the previous two sections do not go to the real root of the flashover problem. None of them really explain how it is possible for a discharge to elongate and bridge a moist film. This section will therefore be devoted to a consideration of the physical processes which may lead to flashover.

One possible mechanism suggested recently (Jolly, 1970) is that localized electrical breakdown occurs at the discharge root. Due to the concentration of current flow lines near the discharge root, the electric field will be fairly high there. If this field is high enough to cause local breakdown of the air surrounding the root, then the discharge would be able to propagate along the surface. The propagation would be in the direction of flashover since the field lines will be more concentrated at the leading edge of the discharge root. The effect may be likened to a lightning leader stroke. Local breakdown would occur out to some distance from the root, then conduction currents through the ionized channel would establish an extension of the discharge, the process repeating until the discharge bridged the insulator, or until the field at the root was insufficient to cause further breakdown.

There is some experimental evidence for this type of breakdown near a discharge root. Frischmann (1957) photographed fine filaments of ionized gas extending from discharge roots just before flashover. He calculated that this occurred at a field strength of about 6 kV/cm. The breakdown strength for air in a uniform field is about 30 kV/cm. For non-uniform fields it is somewhat less, depending on the geometry. Furthermore the breakdown strength of air decreases as it is heated. Thus a value on the order of 6 kV/cm. is not unreasonable for the breakdown strength near a discharge root.

A crude model can be constructed of this process if it is assumed that the discharge root will move forward whenever the field strength at the root exceeds some constant value E_0 on the order of 6 kV/cm. If the discharge root is approximately circular, then the radial field strength in kV/cm at the discharge root will be

$$E = \frac{I\Omega}{2\pi r_a} \tag{3.13}$$

where I is the discharge current in amps, r_a is the discharge root radius in cm., and Ω is the surface resistivity in kΩ per square.

According to Näcke (1966), a discharge root on a moist film has a constant current density of 1.27 A/cm^2 for currents between 40 and 400 mA. Wilkins (1969) gives a value of 1.45 A/cm^2 regardless of polarity, but does not give the current range. Using the value of Näcke, the discharge root will have a radius in cm. of

$$r_a = 0.50\sqrt{I} \tag{3.14}$$

The critical condition for flashover will occur when the field of (3.13) equals E_0. This occurs at a current

$$I_{crit} = \left(\frac{\pi E_0}{\Omega}\right)^2 \tag{3.15}$$

Substituting this into the general expression (3.3), the voltage necessary for discharge root motion as a function of discharge length is

$$V = Ax_{arc} \left(\frac{\Omega}{\pi E_o}\right)^{2n} + \frac{B(\ell - x_{arc})^m}{\Omega} (\pi E_o)^2 \tag{3.16}$$

The critical voltage will be given by the maximum value of (3.16) with respect to x_{arc}. For the simple case of the flat plate, $m = 0$, and the maximum occurs at $x_{arc} = \ell$. In this case the critical voltage is

$$V_{crit} = A\ell \left(\frac{\Omega}{\pi E_o}\right)^{2n} + \frac{B}{\Omega} (\pi E_o)^2 \tag{3.17}$$

For the case where the discharge root radius is assumed independent of current, the resulting flat plate flashover voltage is (Jolly, 1970)

$$V_{crit} = 2\pi r_a E_o B + \frac{A\ell}{2\pi r_a E_o} \Omega \tag{3.18}$$

Another possibility is that the breakdown mechanism is not electrical as just discussed, but thermal. The current density is the discharge column will tend to be greatest near the leading edge of the discharge root. Due to this concentration of current, thermal ionization will occur preferentially at the leading edge, while the trailing edge will cool. Thus the discharge root will tend to move forward as the air there becomes ionized and conducting, while the air behind it cools. Due to the complexity of this problem, the prospects are dim for calculating the threshold current for this type of motion. However if the threshold is always below the critical current of Obenaus, for example, then flashover will occur whenever Obenaus' critical current is exceeded.

Another possibility is that the forces acting on the discharge actually pull it across the water film. There have been several forces suggested, namely, electrostatic (Obenaus, 1933), electromagnetic (Frischmann, 1957), thermal forces (ibid), and steam pressure (ibid). It is instructive to make some order of magnitude estimates of these forces. For a typical discharge current of 100 mA and a typical surface resistivity of 50 kΩ, the discharge root radius using (3.14) will be about 0.15 cm. The electric field at the discharge root given by (3.13) is 5.3 kV/cm. The electric force acting on the discharge root region will be on the order of 1/2 $\varepsilon_0 E^2$ times a characteristic area, or

$$F_{\text{electric}} = \frac{1}{2} \varepsilon_0 E^2 r_a^2 = 2.8 \times 10^{-6} \text{ newtons} \tag{3.19}$$

The electromagnetic forces will be on the order of the magnetic field stress times a characteristic area, or

$$F_{\text{magnetic}} = \frac{1}{2} \mu_0 H^2 r_a^2 = \frac{1}{2} \mu_0 \left(\frac{I}{2\pi r_a}\right)^2 r_a^2 = 1.6 \times 10^{-10} \text{ newtons} \tag{3.20}$$

The thermal buoyancy forces acting on a length r_a of the hot (∿5000°K) discharge column is about

$$F_{\text{thermal}} = \rho_0 g(\pi r_a^2) r_a = 1.3(10^{-7}) \text{ newtons} \tag{3.21}$$

where ρ_0 is the density of air.

The steam force is not as easy to estimate, and it is not even clear in which direction it acts.

Thus for the forces considered, the electromagnetic force is probably negligible. For the conditions specified the electrostatic force dominates the thermal force by about a factor of five. However a factor of five is not particularly significant considering the crude approximations. In any event a factor of five evaporates rapidly if the specified conditions are changed slightly. For lower currents the electric forces would dominate, while thermal forces would take over at higher currents. If these forces are capable of causing motion of the discharge root below the critical current of Obenaus' model, then Obenaus' criterion will give the critical condition for flashover.

3.5 Theoretical Interpretation of the Flat Plate Data

Using the plot of resistivity-vs.-flashover voltage of Fig. 2.6, the critical flashover resistivity as a function of applied voltage can be approximated by

$$\Omega_{crit} = 0.135\ V_{rms}^{3.26} \tag{3.22}$$

where Ω is in kΩ per square and V_{rms} is the applied voltage in kV rms.

In order to compare this expression with the prediction of the extinction theory of Obenaus it is necessary to determine the geometrical resistance factor B. The series resistance seen by the discharge is essentially the resistance between a small disc (the discharge root) and the outer ring electrode. To simplify the problem the center brass electrode will be ignored. This is probably a good approximation since most of the current flow is between the root and the outer ring, and not back towards the inner electrode. For a uniform surface resistivity the problem can be solved exactly by, for example, the method of images. However advantage may be taken of an interesting fact noticed by McElroy. He found theoretically that the resistance between the discharge root and the outer electrode is almost independent of the root position until it is within a few root diameters of the outer electrode, where it begins to decrease rapidly. Thus, except for discharge roots very near the outer electrode, the resistance will be the same as if the root were at the center, or

$$R = B\Omega = \frac{\Omega}{2\pi} \ln \frac{R_o}{r_a} \tag{3.23}$$

where R_o is the inner radius of the outer electrode and r_a is the discharge root radius. Using R_o = 5" and finding r_a from (3.14), the series resistance becomes

$$R = B\Omega = \frac{\Omega}{2\pi} \ln \frac{25.4}{\sqrt{I}} \tag{3.24}$$

where I is the discharge current in amperes. The factor B is plotted in Fig. 3.3 for typical values of current. It can be seen that for reasonable currents B is relatively constant. If a value of 0.7 is selected for B, then the error will be less than 10% over a current range of 40 to 220 mA. Thus to a first approximation m can be set equal to zero in (3.2). According to Table 3.1 the critical resistivity should then be

$$\Omega_{crit} = \frac{n}{B(A\ell)^{1/n}} \left[\frac{\sqrt{2}\, V_{rms}}{n + 1} \right]^{\frac{n+1}{n}} \tag{3.25}$$

It is apparent that this is the same form as the observed dependence (3.22). Setting (3.22) and (3.25) equal to each other, the parameters A and n can be found.

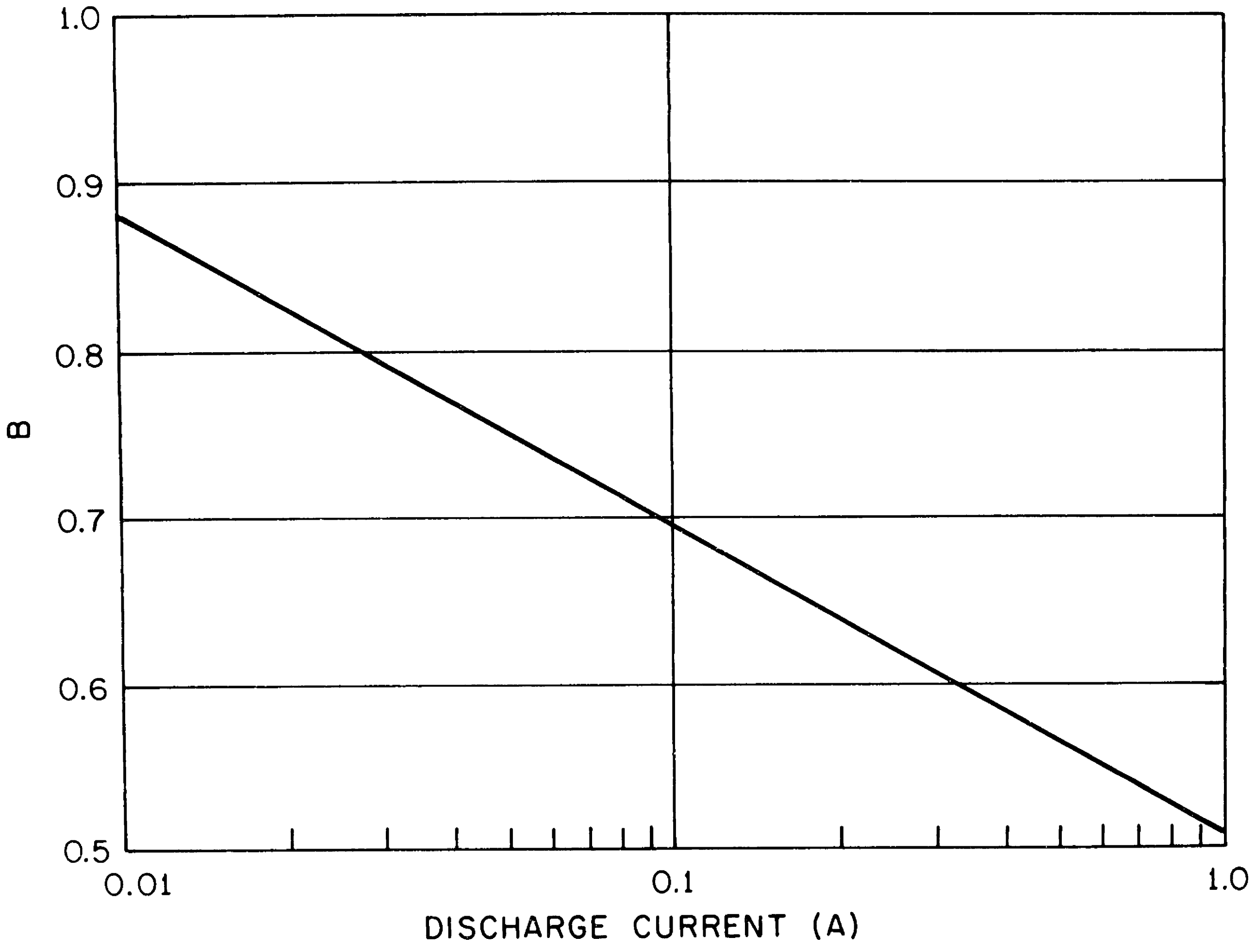


Fig. 3.3 Flate plate resistance factor B as a function of discharge current

$$\frac{V_{arc}}{x_{arc}} = AI^{-n} = 0.189\ I^{-0.44} \qquad (3.26)$$

where V_{arc} and I are the instantaneous discharge voltage (kV) and current (A), and x_{arc} is the discharge length (cm).

It should be possible to check this model for consistency by comparing the discharge current records with theory. Using (3.5) and (3.6) it can be shown that the minimum discharge current on a withstand test will occur for the maximum possible discharge length. After some algebra it is found that

$$I_{min} = \frac{n}{n+1} \frac{\sqrt{2}\ V_{rms}}{\Omega B} \qquad (3.27)$$

On withstand tests there should be no current peaks below this value since there are no stable discharges possible for lesser currents. Table 3.2 lists some of the smallest discharge current peaks observed on withstand tests. The column labelled "no heating" lists the predicted minimum current of (3.27). It can be seen that the observed currents far exceed the predicted minimum. While this is not a contradiction it is nevertheless strange that the minimum is not more closely approached. It may be that multiple discharges in parallel cause the actual current to be higher. However it would seem that a single discharge would occur once in a while.

It turns out that electrolytes experience a substantial decrease in resistance as they are heated. Näcke (1966) assumes that in wet contaminant testing the entire film will approach the boiling point with a consequent resistivity reduction of 2.94. He

Table 3.2

Minimum Values of Discharge Currents

Applied Voltage (kV_{rms})	Surface Resistivity (kΩ)	Minimum Peak Current Observed (A)	Expected Minimum Peak Current	
			No Heating (A)	Full Heating (A)
6	66	0.320	0.059	0.177
7	90	.360	.051	.152
8	85	.145	.061	.183
	122	.140	.043	.128
	134	.080	.039	.116
9	163	.140	.036	.108
	184	.110	.032	.095
10	230	.120	.028	.085
	251	.105	.026	.078
12	349	.100	.022	.067
	473	.080	.016	.050
15	1330	.043	.007	.022

ignores evaporation. Wilkins (1969) states that the resistance of electrolytes may fall by a factor of 2.76 to 3.00 as they are heated from room temperature to boiling. He then goes on to numerically solve the transient heating problem for a wet contaminant type of test where the voltage is applied suddenly. He assumes that flashover occurs the instant any section of the film reaches 100°C. He then corrects the series resistance seen by the discharge with an average correction factor which completely neglects local variations in resistivity. He also ignores evaporation. His model fails for a rectangular plate since ideally the surface would evaporate simultaneously everywhere. He gets around this by assuming an arbitrary reduction factor of 1.8 which leads to a good data fit.

Both of these attempts neglect the local heating at the discharge root which can be very intense due to the current concentration. The power density at the root edge, E^2/Ω, can be as high as 3 or 4 kilowatts per square centimeter. The thermal problem can be roughly approximated as a constant power input at the surface of an infinitely thick slab. This problem can be solved exactly,* and using the thermal conductivity and specific heat of Pyrex it is found that at these power densities the boiling point will be reached in less than a millisecond. Further away from the root it will take longer. However the total resistance seen by the discharge is most sensitive to the region near the root. Thus a substantial resistance

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*See e.g. Carslaw, H., and J. Jaeger, "Conduction of Heat in Solids," Oxford (1947) p. 222.

reduction will occur. The maximum possible reduction would be about 3.0. The lowest possible current peak value corresponding to a reduction of 3.0 is listed in Table 3.2 in the "full heating" column. These values correspond more or less to the actually observed minimum values. The disagreement at 6, 7, and 15 kV may be due to two discharges existing in parallel. Thus the model of Obenaus is reasonably self consistent within the limits of the approximations and the experimental error. If a resistance reduction by a factor of 3.0 is assumed, then the discharge equation becomes

$$\frac{V_{arc}}{x_{arc}} = AI^{-n} = 0.307\ I^{-0.44} \tag{3.28}$$

Since the true resistance reduction is probably between 1.0 and 3.0 the true value of A probably lies somewhere between the values of (3.26) and (3.28).

The value of n is somewhat lower than obtained by other investigators. McElroy (1969) used 0.8, Wilkins (1969) used 0.76, and Claverie (1970) used 0.5. Mathes (1971) has done flashover tests on insulators subjected to a heavy continuous conducting spray. In this case the wet film is constantly renewed and a quasi-steady state condition exists. He found that the flashover voltage varied as the 0.28 power of resistivity for vertical insulators and as the 0.32 power for horizontal installation. Consulting Table 3.1, this exponent should equal $n/(n+1)$, which is 0.31 for $n = 0.44$. Thus a value of $n = 0.44$ is not inconsistent with the data of Mathes. It should be borne in mind that the exponential representation of the discharge voltage is after all just an approximation. A and n are not really constant over a large current range. Furthermore the discharge may be affected by the metal of the electrode or by the dissolved salts.

As for the effects of cathode and anode voltage drop, Näcke (1966) quotes a value for the sum of 830 volts and Wilkins (1969) a value of 840 volts. For the flat plate this amounts to about 10% of the applied voltage, and to the accuracy presently meaningful may be neglected.

In view of the above agreement with the extinction theory of Obenaus it is not possible to advocate any other theory at present. Furthermore it is not yet possible to say what physical processes are involved in discharge elongation. More careful experiments must be done using various geometries, probably taking simultaneous high speed motion pictures and discharge current records. Only such an extensive study can determine the physical processes involved.

3.6 Summary and Conclusions

This chapter dealt with some theoretical aspects of the flashover process. The extinction model of Obenaus was considered and extended slightly to cover both long rod and flat plate insulators. The theory of Hampton was found to be identical to Obenaus' model for the long rod. However there is no basis for applying it to other geometries as has been done by Wilkins. The approach of Näcke appears to have no physical basis.

Several physical breakdown mechanisms were considered in Section 3.4. It was shown that the electric forces acting on the discharge were on the order of the thermal buoyant forces. Flugum (1971) has demonstrated experimentally the importance of the buoyant force acting on discharges which have detached from the insulator surface. Thus electric forces may also affect such discharges.

However other mechanisms may be involved for discharges moving rapidly along an insulator surface. Hesketh (1967) has observed propagation velocities of up to 600 meters/second for discharges moving along a water column. Such high velocities suggest that electric breakdown at the discharge root (Jolly, 1970) may be the driving mechanism.

Since the flat plate data can be fitted to the theory of Obenaus without regard to any particular driving mechanism, there is no real basis for deciding what causes the discharge to move. More detailed experiments need to be done to determine the physical basis of discharge elongation, and the electric breakdown model should be developed further in order to compare its predictions with experiment.

CHAPTER 4

TESTS ON STANDARD SUSPENSION INSULATORS

4.1 Introduction

Since the ultimate application of any contamination study must be to practical insulator geometries, a substantial portion of this thesis was devoted to tests on standard 5 3/4 x 10" suspension insulators. Some initial tests were done to find the effect of a porous clay coating on flashover time. A number of tests were then done on Photoflo coated insulators to determine the effects of voltage and fog salt percentage. Some further tests were done on bentonite coated insulators to examine the role of permeation of water along the surface. Finally, tests were done on field contaminated insulators to correlate with the results of the artificial contamination tests. During the course of these experiments a number of interesting effects were observed for which theoretical explanations were suggested.

4.2 The Effect of Bentonite Level on Time to Flashover

After some exploratory work McElroy (1969) developed a test procedure which involved exposing insulators with a light bentonite coating (0.04 mg/cm^2) to 9% salt fog and an 8 mph wind under a voltage stress of 15 kV. In 11 tests conducted under these conditions he obtained a range of flashover times of 16.5 to 37.3 minutes with a mean time of 26.3 minutes. In one of these tests the insulator withstood for 42 minutes and the test was terminated. Insulators with heavier bentonite coatings sometimes lasted for over an hour without flashing over. Bentonite and similar materials are often referred to as "inert" contaminants since they contribute few conducting ions. However it would appear that the "inert" contaminant does have some effect on flashover time.

Accordingly some tests were run on bentonite coated insulators. A series of a few dozen exploratory tests was done using various levels of bentonite. However the results were erratic, with flashovers occurring at seemingly random times, and nothing of value was discovered.

One possibility for the random behavior is that, even though two insulators may have the same average bentonite density, there may still be some uncontrolled differences in the coating such as in texture or distribution. The only way of assuring an identical surface treatment is to test the same insulator more than once, that is, expose it repeatedly to a series of weather cycles. Each cycle would consist of exposing the insulator to fog and voltage until flashover, and then drying it for another test. It would be expected that the flashover time would decrease steadily from cycle to cycle as the deposits of salt accumulated on the surface of the insulator. Such was not the case however.

Two such series of tests were run, ten weather cycles on an insulator with a very heavy bentonite coating, and twelve on a medium coated insulator. The insulators used were Locke 5 3/4 x 10" standard suspension units. The profile of this insulator is shown in Fig. 4.1. The test results are summarized in Table 4.1. The insulators were stressed at 15 kV, but if no flashover occurred by 30 minutes, the voltage was raised 200 volts every second until it did occur, the voltage required in these cases being noted in the table.

Fig. 4.1 (Opposite). Profile of Locke 20,000 lb., 10" diameter insulator used in all tests described in Chapter 4. The bottom inner washing region extends from the pin to the bottom of the 2nd skirt. The bottom outer region extends from the bottom of the 2nd skirt to the bottom of the 4th. The list below indicates locations where dry zones were observed.

Dry Zone Location	Abbreviated Notation Used in Tables 4.1 and 4.4
From pin to A	P
From A to B	1
From B to C	2
Around cap	Cap

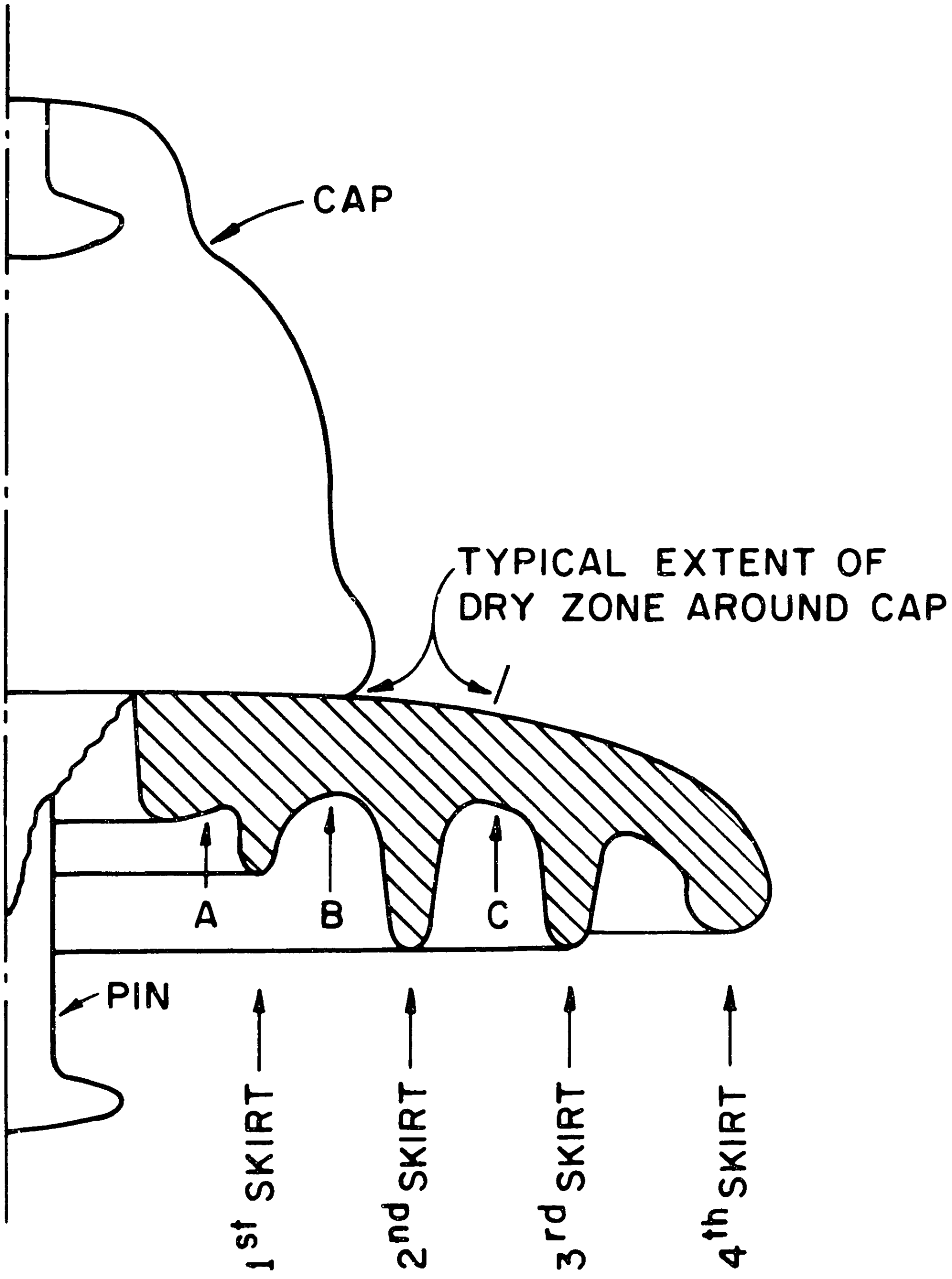

CAP
TYPICAL EXTENT OF DRY ZONE AROUND CAP
A
B
C
PIN
1st SKIRT
2nd SKIRT
3rd SKIRT
4th SKIRT

Fig. 4.1 (Cont.)

Table 4.1

Multiple Cycle Tests on Bentonite Coated Insulators

Heavy Bentonite

Weather Cycle	Time of Flashover[*] (minutes)	Dry Zone[+] Location(s)	Scintillations(?)
1	30W (18.2 kV)	1	no
2	30W (23.6 kV)	2	no
3	27.0	1	no
4	30W (24.8 kV)	2	no
5	28.1	1	no
6	20.7	1,P	yes
7	30W (17.6 kV)	2	no
8	9.7	1	yes
9	30W (24.8 kV)	2	no
10	8.5	1,P	no

Deposit Density

(mg/cm^2)

	Top	Bottom Total	Bottom Inner	Bottom Outer
Salt	1.40	3.07	4.15	2.73
Bentonite	0.79	1.20	2.55	0.83

Table 4.1 (Continued)

Medium Bentonite

Weather Cycle	Time to Flashover* (minutes)	Dry Zone+ Location(s)	Scintillations(?)
1	30W (18.0 kV)	1	no
2	15.3	1, 2cm. at cap	no
3	30W (19.0 kV)	1	no
4	30W (18.0 kV)	1	no
5	14.5	2.5 cm. at cap	yes
6	17.0	1	no
7	15.6	1	no
8	11.3	1, P, 1.5 cm. at cap	yes
9	10.6	2 partly dry	no
10	11.0	1	no
11	20.2	1, P	no
12	30W (25.2 kV)	2	no

Deposit Density

(mg/cm^2)

	Top	Bottom Total	Bottom Inner	Bottom Outer
Salt	0.63	0.93	2.02	0.64
Bentonite	0.18	0.25	0.47	0.19

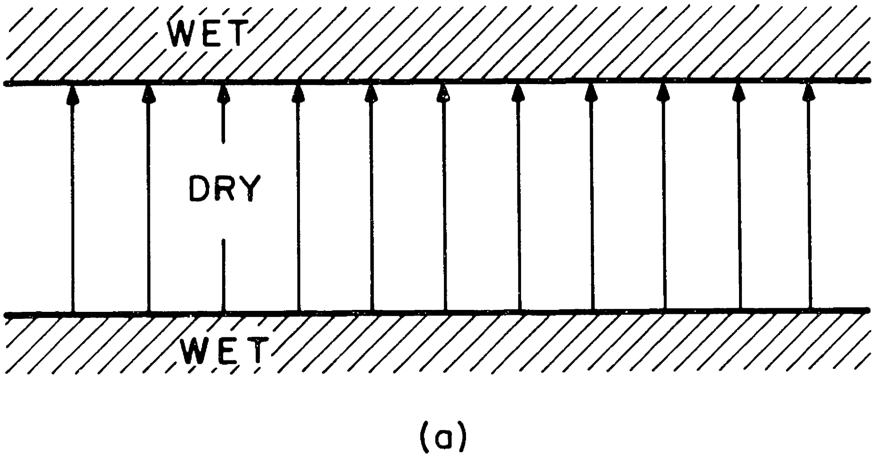
---

[*] W indicates withstand

[+] See Fig. 4.1 for key to locations

Several observations may help explain these erratic results. Scintillations were observed in only 4 cases, and in each of these cases flashover occurred in a reasonably short time. Furthermore, when flashover did occur, whether at 15 kV or while the voltage was being raised, it was usually sudden and without warning. After 30 minutes of fog the test insulator would be dripping wet, and could apparently get no wetter. It would seem from all this that the insulator can be below critical resistivity but not flash over since the dry zone never breaks down. This interpretation is verified to some extent by the relation of breakdown voltage to dry zone location. When the 1st skirt was dry, it required an average of 18.3 kV in 4 cases to cause flashover. For dry zones on the larger 2nd skirt it required an average of 23.2 kV in 5 tests. Thus, although the insulator is dripping wet and far below critical resistivity, flashover is prevented by the formation of a dry band wide enough to withstand the entire voltage.

It is worth considering how such a dry band can resist any local narrowing which would lower the breakdown strength. The stability can be clarified if we consider a segment of dry band as shown schematically in Fig. 4.2. If part of the boundary begins to move inward due to irregularities in the coating or due to the impact of a water droplet, the electric field lines will tend to concentrate as shown. This will cause increased local heating due to increased corona and increased resistive heating. This will tend to evaporate the water in the salient and drive the boundary back. Thus the dry band will tend to remain circular on a perfectly uniformly



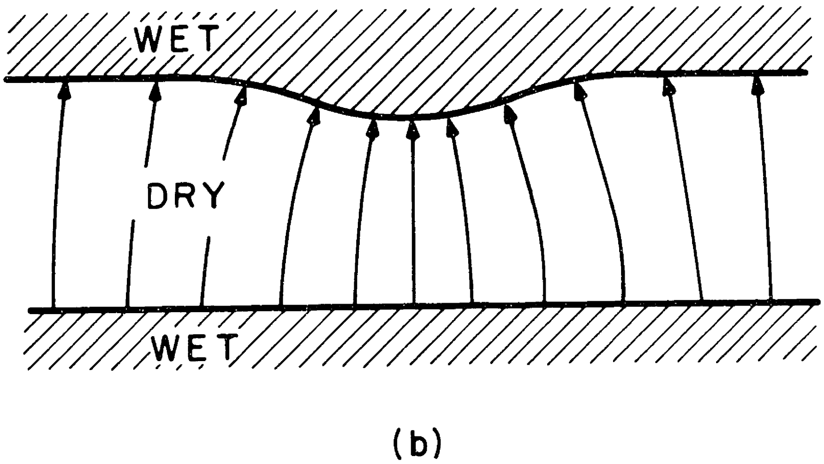


Fig. 4.2 Schematic representation of dry band stability. (a) shows the current flow and electric field lines when the band edges are parallel. If one boundary begins to migrate inward due to a water droplet impact, for example, the field lines will concentrate as shown in (b). The increased corona and resistive heating will tend to evaporate the bulge, maintaining a dry band of uniform width. If this width is large enough, the dry band will be able to sustain the entire applied voltage without breaking down, and flashover will not occur.

coated insulator. Of course under field conditions things are not quite so ideal, and a stable dry zone is less likely to form.

Because a heavier coating would more strongly resist the movement of water along the surface, heavier coatings should form the most stable dry zones. This agrees with the results of McElroy (1969) which show the heavily coated insulators lasting longest. In the next section tests are described in which no bentonite at all was used. In these tests the insulator was rarely able to last more than 15 minutes under the conditions used here. Apparently a porous surface coating is needed for a stable dry zone to form.

Dry zones wide enough to suppress scintillation are less likely to occur on strings than on one unit. Because of the non-uniform voltage distribution along a string, the stress will probably always be high enough to break down one dry zone, overstressing the others, and causing scintillations along the entire string.

A valuable lesson was learned from these tests, namely that time to flashover is not a good measure of performance when scintillations are not occurring. The insulator under test may be ready to flash over but can't because of a dry zone wide enough to sustain the entire voltage. Special care should be taken in testing single units. Any test in which flashover is sudden and not preceded by scintillations should be examined to see if such a mechanism could be operating.

Flashover without warning has incidentally been observed under actual operating conditions. In one case an engineer was standing near a large 4-part 66 kV bus bar insulator. According to him, "Flashover occurred during a heavy fog when everything was dripping wet. The insulator itself was perfectly dark and showed no signs of overstress, but arced suddenly and without any warning whatsoever." (Hillebrand and Miller, 1934). The paper of Obenaus (1960) contains a discussion of flashover without any visible pre-discharge.

There is still another reason why the tests described here were erratic. In one of the last tests condensation was observed on the insulator surface before the fog was applied. This apparently was caused by the cool draft from an air conditioner about 15' from the insulator preparation and storage area. In order to avoid condensation in future tests, the air conditioner was not used for the remainder of the summer. Although this made the test personnel uncomfortable, the more reliable results justified the discomfort. As a further precaution, insulators were always placed in the fog chamber at least 10 minutes before testing with the fan on to allow them to reach ambient temperature. The tests described in the rest of this chapter were all carried out with these precautions. A measure of their effectiveness is found in Section 4.5 where additional bentonite tests are described. In those tests the dry zone almost invariably formed around the pin as would be expected from the concentration of the current there.

4.3 The Effects of Voltage and Reservoir Salt Concentration on Time to Flashover

In most of his testing McElroy (1969) used 9% NaCl fog. Naturally occurring fogs are believed to have a substantially smaller equivalent salt concentration. It would therefore be desirable if

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4.3 The Effects of Voltage and Reservoir Salt Concentration on Time to Flashover

In most of his testing McElroy (1969) used 9% NaCl fog. Naturally occurring fogs are believed to have a substantially smaller equivalent salt concentration. It would therefore be desirable if these "accelerated" 9% fog tests could be related to what happens at lower salt concentrations in order to relate to field behavior. On more general grounds, data on the effects of both applied voltage and fog salt percentage would be valuable in constructing a theoretical model of the flashover process.

Because of the previously discussed difficulties in obtaining repeatable results with bentonite coated insulators, tests were done on insulators treated only with Kodak Photoflo-200,* a photographic detergent. The Photoflo was necessary since perfectly clean new insulators would not flash over at working voltage. The Photoflo was always applied in a carefully controlled manner. 16 drops were dripped on the insulator top and spread around with the corner of a Kimwipe.** 13 drops were then spread on the bottom. After spreading the Photoflo over the entire surface the insulator was brushed lightly with a dry Kimwipe to remove any excess Photoflo.

The test insulator was then placed in the fog chamber as the center unit of a 3 unit string. The bottom unit was shorted internally by a pin driven through the cap. Figure 4.3 shows the test setup. The top and bottom units provided more realistic airflow conditions, and the bottom unit also served to keep the high voltage lead clear from the skirts of the test unit. The chamber door was then closed and the fan started. The insulator was left in place for over ten minutes in order to reach thermal equilibrium with the ambient.

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*Registered Eastman Kodak trademark.

**Registered Kimberly Clark trademark.

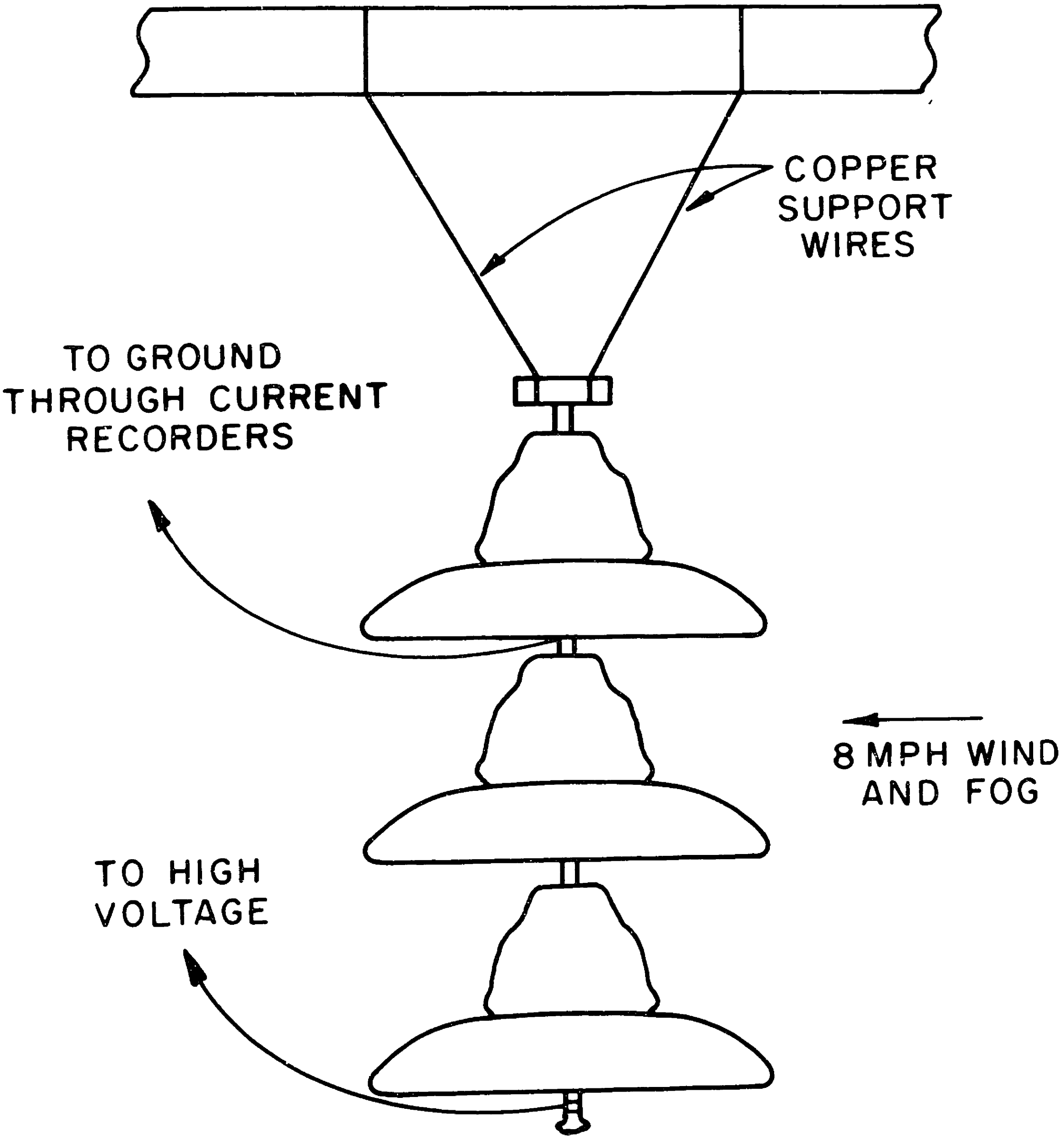

Fig. 4.3 Suspension insulator test arrangement. The center unit is the insulator under test. The top unit is a normal insulator and the bottom unit is shorted internally. The insulators are suspended from a plexiglass support at the top of the fog chamber.

The voltage was then applied, followed by fog about one minute later. Test time was measured from the application of fog.

The insulator leakage current was always monitored with the Esterline-Angus recording galvanometer.* Figure 4.4 shows a typical leakage current record. Some Visicorder* discharge current records were also obtained, but often there were no discharge surges before flashover.

Table 4.2 shows the test results. Fifty tests were done at various voltages and salt concentrations. As noted in the table there were a few special tests. At 15 kV and 9% fog, Test 12 consisted of two cycles on a clean (no Photoflo) new insulator. Despite the large final salt concentration there was no flashover in two hours. Photoflo coated insulators required 10-15 minutes to flash over under the same voltage and fog conditions. At 15 kV and 9% fog there were also two tests in which the insulator was coated with over 5 times the normal amount of Photoflo. If anything, these two insulators seemed to flash over slightly before the mean time of those getting the standard treatment. All other tests were done using insulators treated in the standard way. The large number of tests at 15 kV and 9% fog resulted from the practice of using these conditions each morning to check out the fog chamber as a precaution against any unnoticed changes in the test conditions.

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*see Appendix 1 for circuits and specifications.

Table 4.2

Results of Salt Fog Tests on Photoflo Coated Insulators

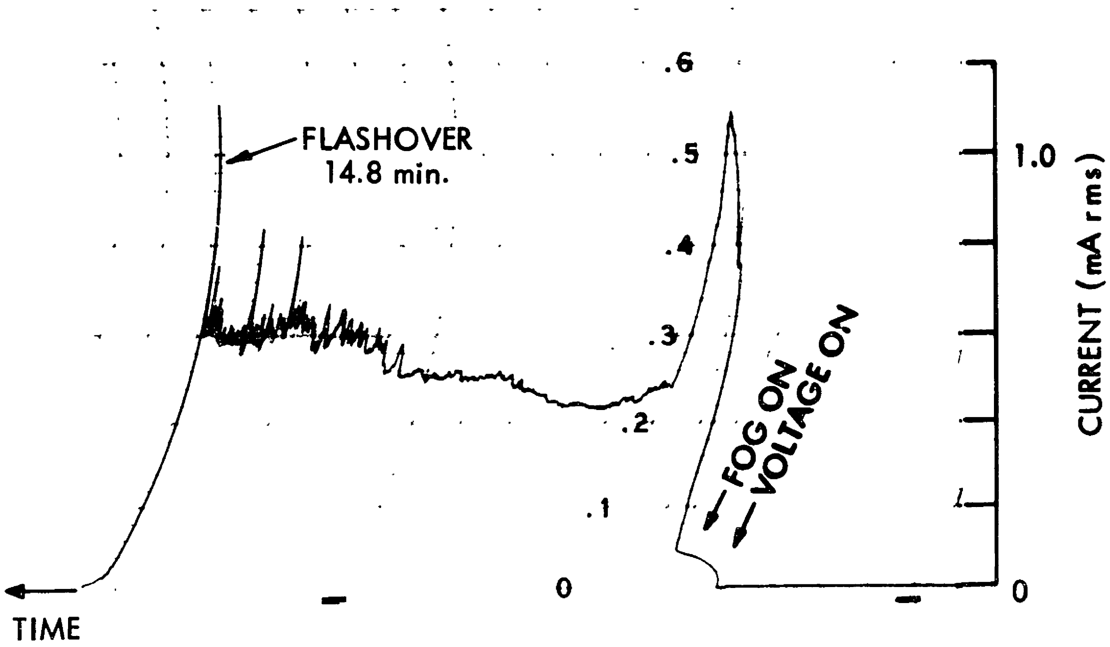
1% NaCl Fog

Voltage (kV)	Test No.	Time to Flashover (min)	Final Salt Density (mg/cm^2)				Comments
			Top	Bottom Total	Bottom Inner	Bottom Outer	
15	1	44.9	0.028	0.053	0.106	0.039	
17.5	1	19.5	.018	.041	.085	.029	
20	1	15.8	.015	.040	.080	.029	
25	1	11.0	.011	.031	.085	.016	
3% NaCl Fog							
12.5	1	29.8	0.051	0.133	0.35	0.075	
15	1	13.5	.035	.060	.160	.033	
	2	16.7	.039	.075	.170	.049	
17.5	1	11.6	.026	.065	.149	.042	
20	1	8.6	.024	.058	.192	.022	
25	1	5.7	.015	.058	.197	.020	
9% NaCl Fog							
9	1	120W*	0.125	0.42	1.42	0.157	
10	1	42.9	.066	.160	.27	.131	
	2	51.9	.073	.26	.55	.177	
11	1	12.2	.074	.139	.21	.121	
	2	14.8	.081	.127	-	-	
12.5	1	11.4	.057	.112	.186	.092	
	2	11.4	.072	.107	-	-	
	3	14.5	.082	.131	.22	.108	
	4	20.6	.079	.160	-	-	
15	1	9.5	.083	.138	-	-	
	2	9.6	.073	.131	.35	.072	Extra Photoflo
	3	10.1	.070	.129	-	-	
	4	11.0	.083	.118	.23	.088	
	5	11.3	.081	.145	.34	.078	Extra Photoflo
	6	11.5	.070	.105	.23	.070	
	7	12.8	.082	.155	.29	.118	
	8	13.9	.079	.181	.32	.143	
	9	14.6	.090	.157	.24	.135	

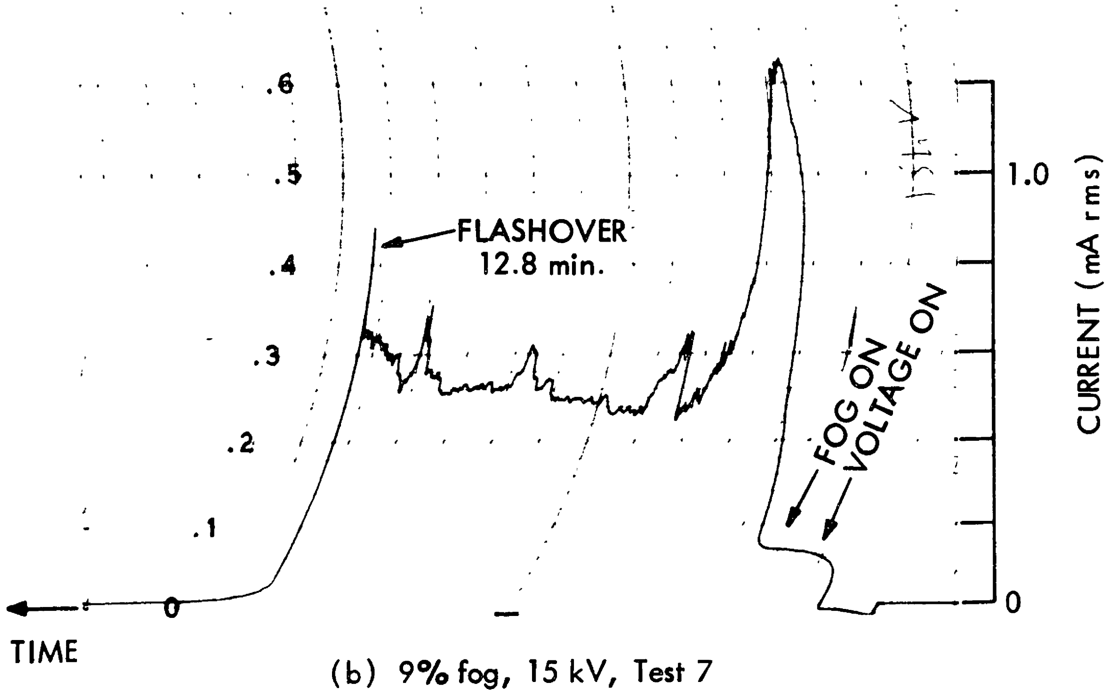
Table 4.2 (Continued)

Voltage (kV)	Test No.	Time to Flashover (min)	Top	Bottom Total	Bottom Inner	Bottom Outer	Comments
	10	15.4	.084	.142	.29	.100	
	11	17.2	.123	.22	-	-	
	12a	60W*	-	-	-	-	No Photoflo
	12b	60W*	.73	.92	1.44	.78	"
17.5	1	5.2	.037	.052	.133	.030	
	2	10.3	.048	.128	.181	.113	
20	1	3.7	.029	.063	.144	.040	
	2	5.3	.028	.086	.23	.046	
22.5	1	3.7	.029	.080	.181	.053	
25	1	2.4	.022	.045	.124	.023	
18% NaCl Fog							
8	1	60W*	0.176	0.30	0.82	0.161	
9	1	26.7	.154	.25	.47	.193	
10	1	24.2	.143	.27	.63	.177	
11	1	22.7	.117	.21	.38	.170	
	2	40W*	.167	.22	.58	.129	
12.5	1	13.5	.123	.22	.53	.131	
	2	21.1	.198	.26	.40	.22	
	3	26.3	.136	.34	.81	.21	
	4	30W*	.057	.27	.61	.180	2nd skirt dry
15	1	6.4	.062	.086	.170	.063	
17.5	1	4.8	.061	.120	.31	.069	
20	1	4.8	.083	.146	.43	.069	Possible salt error
25	1	2.4	.094	.083	.15	.065	

*W indicates withstand



(a) 9% fog, 11 kV, Test 2



(b) 9% fog, 15 kV, Test 7

Fig. 4.4 Typical leakage current behavior of Photoflo coated insulators

In order to better show the trend of the data, the minimum flashover times have been plotted in Fig. 4.5. The minimum times were used since they probably better represent the "true" flashover time. Longer times may result from a poor Photoflo coating or from the formation of a dry zone wide enough to sustain the entire voltage without breaking down.

Several overall trends are apparent at once. Higher voltage and higher salt concentration both lead to quicker flashover as expected. Another expected result is that for any given salt concentration there is a minimum voltage below which flashover cannot be obtained. This is because the insulator surface is only able to hold a certain thickness of water without runoff. The insulator can have more salt per unit area (i.e. greater surface conductivity) and thus a lower minimum flashover voltage for a greater salt concentration.

There are however some apparent irregularities in the curves. The 9% curve appears to be discontinuous at about 17.5 kV. The trend of the curves suggests that the curve below 17.5 kV should perhaps be lower. In other words something appears to be inhibiting flashover below 17.5 kV at 9% salt. If the observation that these flashovers were not preceded by any scintillations is taken into account, a tentative explanation of this discontinuity can be made. When the high voltage portion of the curve is extended to lower voltages the dotted line of Fig. 4.5 is obtained. This indicates that at lower voltages the insulator reaches the critical resistivity for flashover some time before the actual occurrence

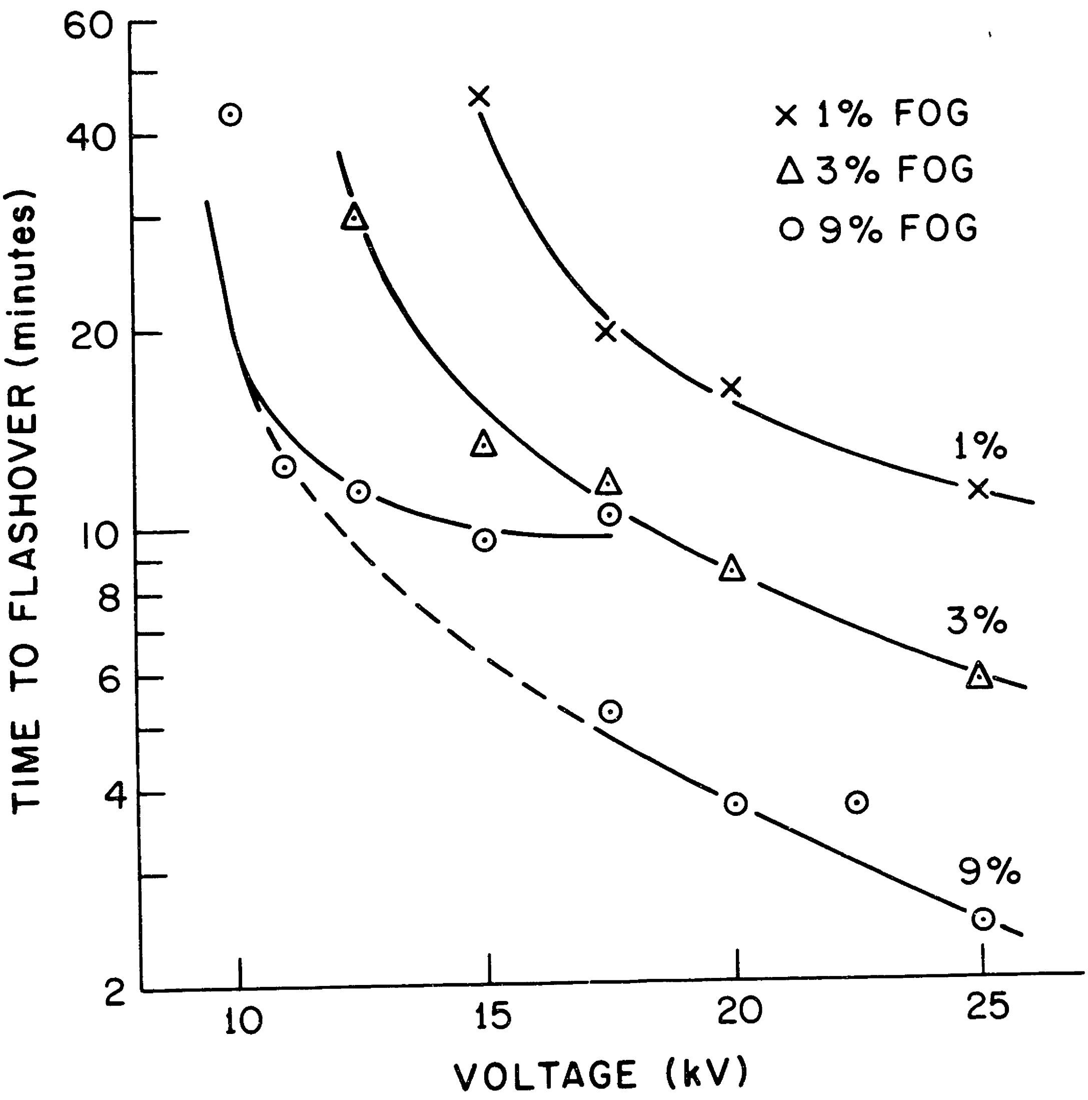
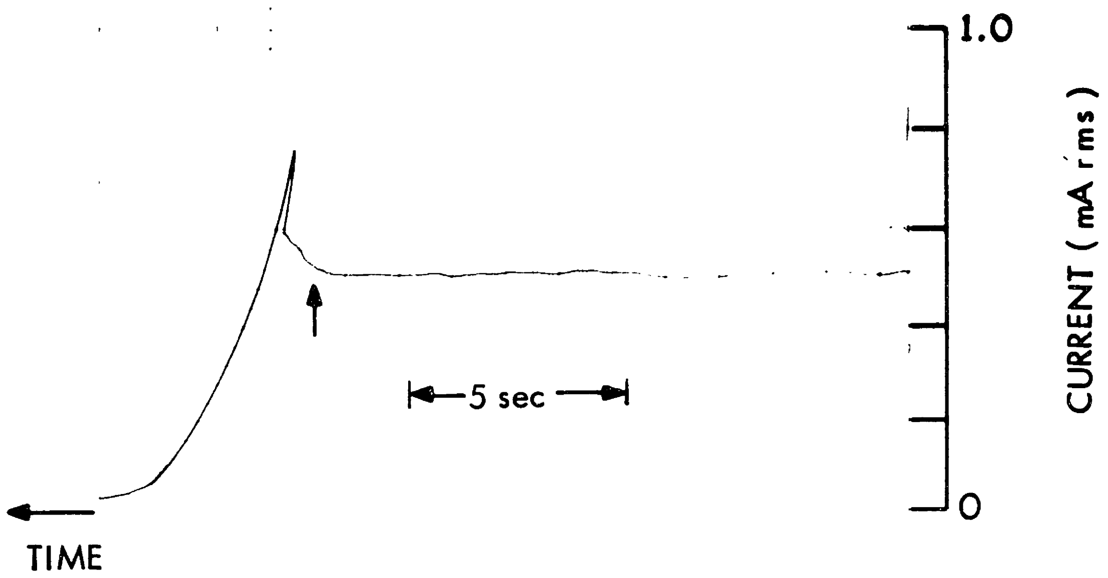
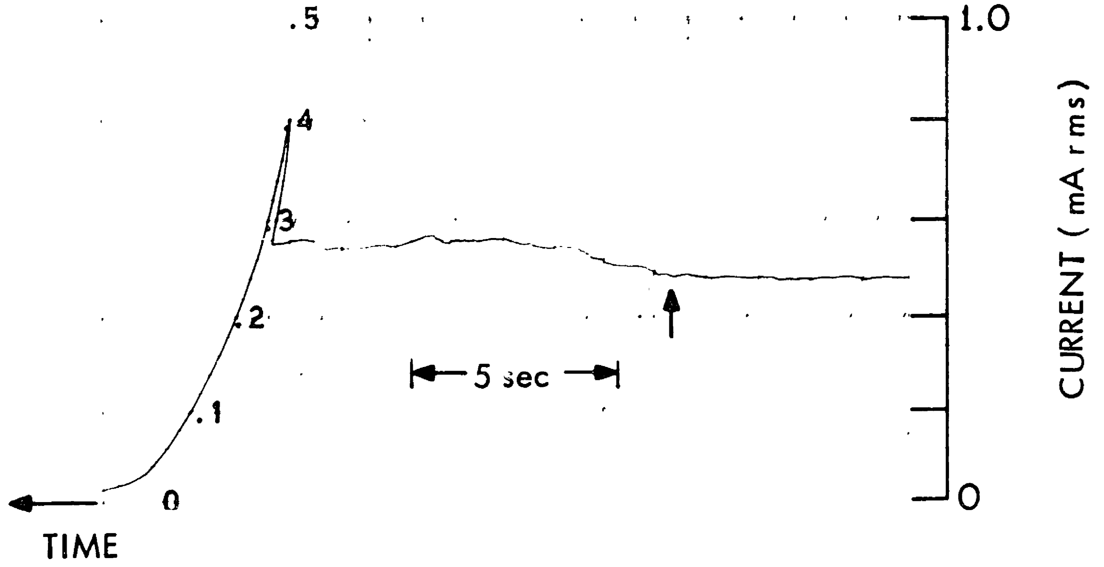


Fig. 4.5 Dependence of minimum time to flashover on voltage and fog salt percentage for Photoflo coated insulators.

of flashover. At times above the dotted line any scintillation will lead to flashover. Apparently however such a scintillation never occurs until about 10 minutes. The only thing remarkable about 10 minutes is that this is when the insulator bottom begins to drip. One is led to consider how a scintillation could be triggered by the water film reaching the flow limit. One possibility is that a water drop on the bottom of a petticoat could be blown into the dry zone, triggering breakdown. Another possibility is that the electric field may pull a water filament from the boundary of the wet region into the dry zone, also triggering breakdown. This mechanism has been observed on a flat plate model by Frischmann (1957). In the Photoflo series here it was noticed that just before flashover the leakage current often increased slightly. This increase preceded flashover by about one to five seconds. The slow time involved is more suggestive of a thin filament of water being slowly drawn along a surface than of the spattering of a windblown droplet. Since the Esterline Angus leakage current recorder could be speeded up by a factor of 60, two faster records were taken to resolve this current increase. The two records obtained are shown in Fig. 4.6. The jump in current preceding flashover can be clearly seen. It is not necessary for this filament breakdown mechanism to operate above about 17.5 kV since, as shown in Section 4.2, voltages of this order are sufficient by themselves to break down a dry zone at the first petticoat. Thus above about 17.5 kV flashover can occur as soon as critical resistivity is reached.



(a) 17.5 kV, Test 2



(b) 15 kV, Test 8

Fig. 4.6 Leakage current records showing current increase just prior to flashover. The beginning of the increase is indicated by the arrows. 9 % salt fog was used in both cases.

A crude experiment was done to verify the existence of such a mechanism. A gap of a few centimeters was left between two water films about 1 mm. thick on a glass plate. It required about 10 kV to pull a fine water filament across the gap. These numbers are typical of the tested insulators and suggest the mechanism is able to occur. The practical importance of this interesting filament formation is not apparent, and the topic was not considered further. It is felt that under field conditions the dry zones are irregular and the voltage distribution along strings is non-uniform. Thus scintillations probably can always occur due to ordinary electric breakdown.

The suspicious reader will wonder why the data taken at 18% salt fog was omitted from Fig. 4.5. It was left out because it was somewhat erratic. There are two possible reasons for this. The 18% fog tended to form a rather crusty dry zone, and may have stabilized the dry zone against discharging just as bentonite does. Furthermore the apartment of the technician preparing the insulators was burglarized the night before the 18% tests and he was very tired. Since 18% fogs are unlikely to be encountered in nature, the investigation proceeded to more promising topics, leaving the 18% question unresolved.

4.4 The Effect of Surface Conditions

It has long been known that surface conditions play a large role in the flashover process. In particular the formation of water droplets on the surface is affected by the nature of the surface. Using water repellant coatings to cause the water film to bead up is one possible remedy to the contamination problem. Apparently beading interrupts the current flow and prevents dangerous high current discharges from forming. Such coatings may also serve other functions at the same time. For example, silicone or petroleum grease can encapsulate contamination particles by the so called "amoeba effect" (Seta, 1962; Toms and Suttie, 1965). According to a discussion by Baatz and Reverey (Johnson et al., 1968) greased insulators tend to flash over in rain rather than fog. This is apparently caused by the running water forming a continuous film, whereas in fog the water is able to bead.

The performance improvement due to greasing can be substantial. Ely and Lambeth (1964) found that greased insulators lightly dusted with limestone flashed over at double the voltage and four times the fog salinity of clean units in a salt fog test. In view of the performance difference just quoted, it is clear that wettability is very important. This has implications for testing since the various test methods use different surface treatments.

Not too much quantitative work seems to have been done on beading. Smail, Brooksbank, and Thornton (1931) investigated dew formation on porcelain surfaces. They found that as porcelain is cooled, its surface resistivity decreases. However when the dew point is reached a sudden increase occurs, followed by another decrease as the surface cools further. The increase was attributed to the sudden onset of bead formation which hinders the current flow. The authors derived a crude criterion for the threshold film thickness at which beading will occur.

A study more directly applicable to contamination flashover was reported by Estorff and von Cron (1952) in which von Cron identified the flashover mechanism of a beaded film. He found that when sufficient voltage is applied, electric forces will rupture the individual droplets, pulling them into a continuous filament between the electrodes causing flashover. Von Cron also found that a dust layer on the surface lowers the threshold voltage for the formation of these "droplet bridges". He comments that an undusted surface, such as paraffin, causes distinct beads to form, while aslight dust coating lessens this effect. The dust is likened to a capillary network which permits continuous current paths to develop more easily.

Exposure to the elements may change the glaze itself. Werner (1958) remarks that new insulators have a glossy appearnce, while the glaze of insulators exposed to contamination becomes dull. This effect is also noticed on insulators removed from the AEP system. The weathered insulators also seem to have a reduced ability to cause beading. Glaze weathering might thus affect the results of tests where surface wettability is important, e.g. the salt fog test on clean insulators. The use of newly manufactured insulators for such tests may not be a realistic simulation of behavior under natural conditions.

To check the effect of glaze weathering, salt fog tests were done on a clean new and a clean weathered insulator. The insulators were first washed with detergent and then rinsed under hot tap water to remove any leftover detergent. The test procedure consisted of exposing the insulators to 9% salt fog and 8 mph wind at 10 kV for one hour to allow the insulator to become completely wet. The voltage was then raised in steps of 1 kV every two minutes until flashover occurred. After the test the salt was removed with distilled water and a brush in order to determine the deposit density. The insulators were then rinsed with hot tap water and no detergent, and then rinsed with distilled water and hung up to drip dry. They were then retested under the same fog conditions to get a measure of repeatability. There was also some fear that a small amount of detergent may have been present on the first test. Because of time limitations the new insulator was tested 3 times and the field weathered one only twice. The results are summarized in Table 4.3. Except for one flashover at 36 kV all flashovers occurred at about 23 kV independent of weathering. The reason for the 36 kV flashover is not known.

There was a definite difference in the appearance of the two insulators after drying. The salt on the new insulator formed regularly spaced dots about 0.5 mm apart. This was not as evident on the field weathered unit which tended toward scaly, crusty patches of salt.

The difference in wettability is clearly evident from the leakage current records. The initial rate of current increase was about five times greater for the weathered unit. This makes sense since less beading implies a more continuous, more conducting film. The beading evidently sharply limits current flow through the film.

This interpretation is reinforced by the tests on Photoflo and bentonite coated insulators. Both of these surface treatments tend to inhibit beading and should be associated with much higher initial rates of current rise. This is the case as is apparent from

Table 4.3

Effect of Surface Conditions

Test	Surface Condition	Flashover Voltage (kV)	Salt (mg/cm^2) Top	Bottom	Initial dI/dt (mA/hr)
1	new	22	0.38	0.62	0.56
2	new	36	.57	.70	0.48
3	new	23	.46	.55	0.74
4	weathered	25	.35	.60	3.8
5	weathered	22	.42	.55	2.9

Fig. 4.7 which shows a typical leakage current records for the four types of surface treatment.

Although the flashover voltage was about the same for weathered and new insulators, much lower flashover voltages could be obtained with Photoflo coated units. Thus, in order to simulate worst case conditions, beading should be inhibited.

Photoflo has the drawback that it washes off when the insulator begins to drip. A light bentonite coating would probably be best since it resists washing. However tests must be done on strings because of stable dry zone formation as discussed in Section 4.2. Detergent could be added to the fog but this might affect droplet size. In wet contaminant testing there is of course no problem since the surface film is deliberately made continuous.

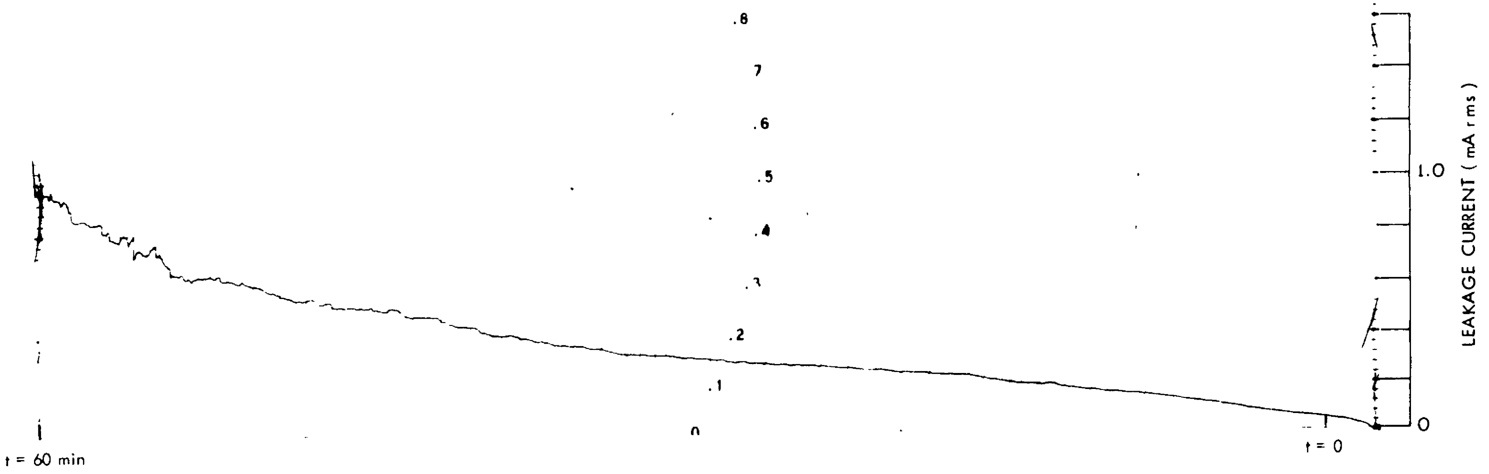
4.5 Permeation and Deposition Measurements

McElroy noticed during this thesis research (1969) that in salt fog tests on bentonite coated insulators the salt tended to concentrate in the region around the pin. This concentration was also noted on field contaminated insulators. There are three possible reasons for the greater contamination around the pin on field insulators:

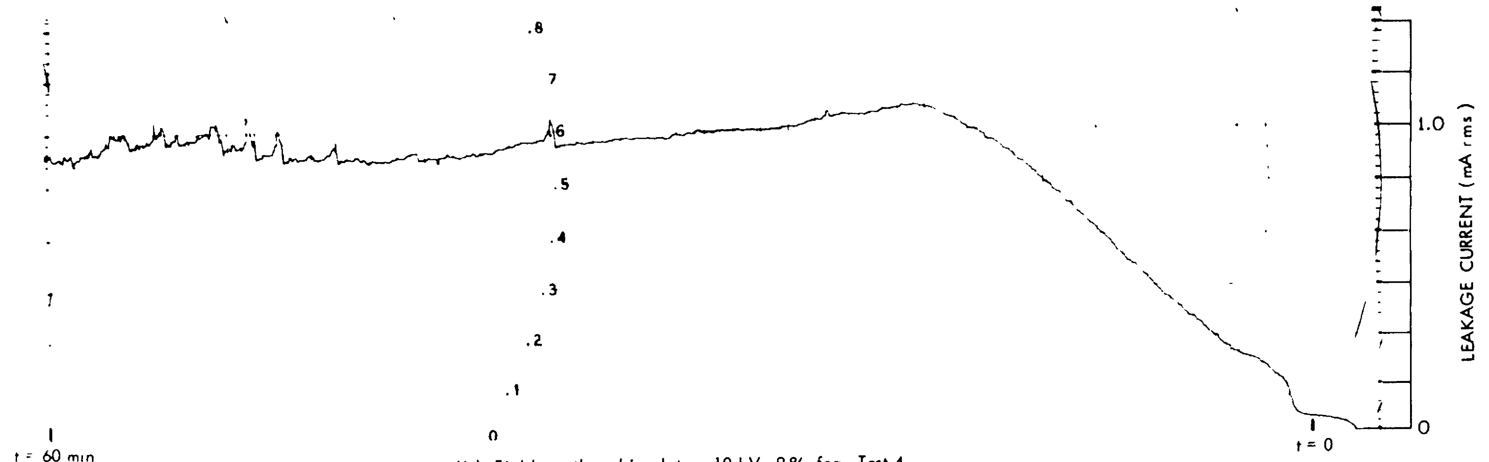
1) The rain is less able to wash the more protected surface near the pin,

2) The high electric field near the pin attracts particles to that region, or

3) Water permeates along the surface from the wet outer region to the dry zone around the pin where it evaporates,

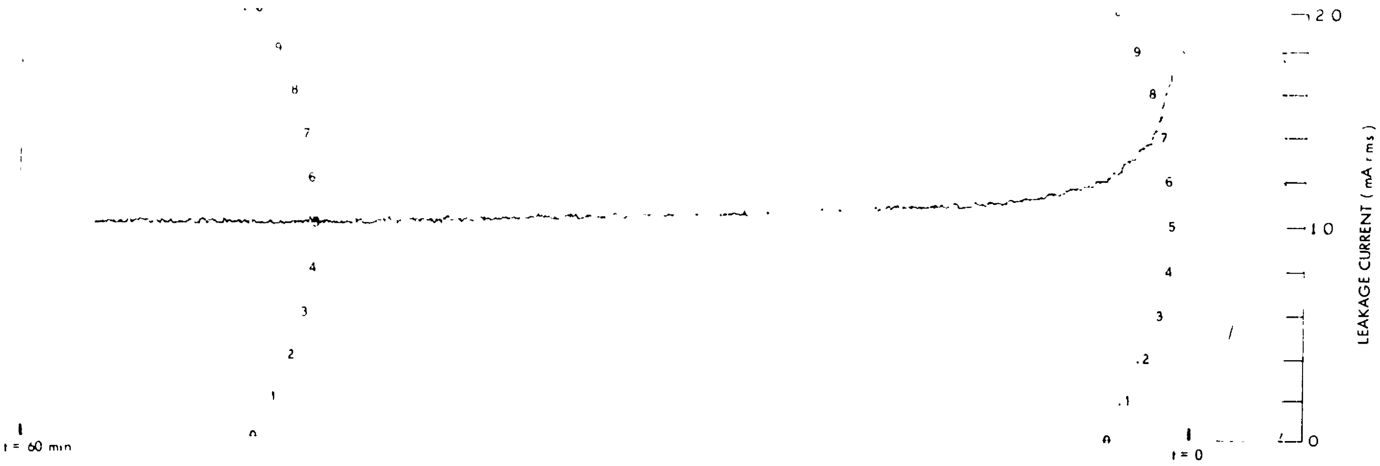


(a) Clean new insulator, 10 kV, 9 % fog, Test 2

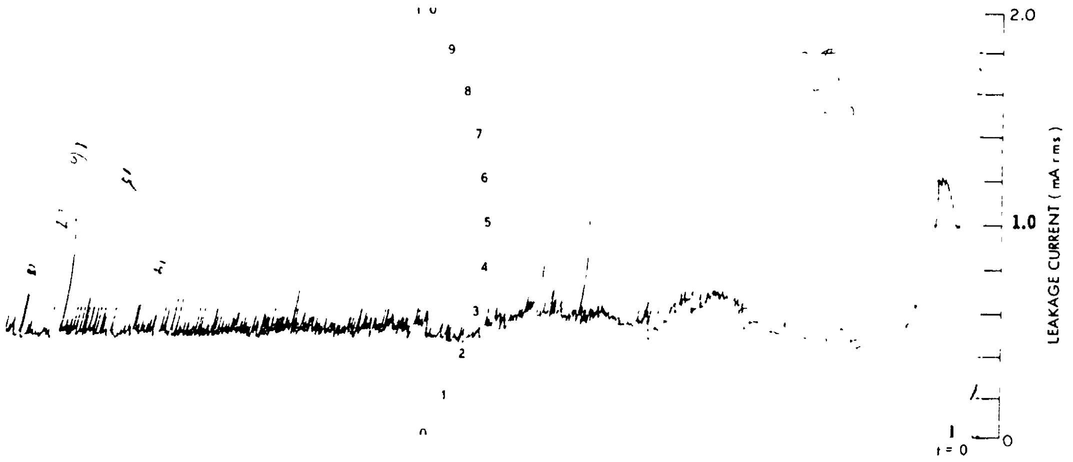


(b) Field weathered insulator, 10 kV, 9 % fog, Test 4

Fig 4.7 The effect of surface condition on leakage current behavior



(c) Bentonite coated insulator, 10 kV, 9 % fog, test 8 of Table 4 3



(d) Photoflo coated insulator, 10 kV, 9 % fog, Test 2, flashover at 51.9 minutes

Fig 4 7 (cont) The effect of surface condition on leakage current behavior leaving behind dissolved salts.

It is likely that the distribution of the contaminant is as important as its average density per unit area (Nasser, 1962; Heise and Köthe, 1966; and Maikopar and Morozov, 1968). Therefore it was decided to do a series of carefully controlled tests in which some of the factors governing the deposit distribution could be studied.

Accordingly 30 tests were done using bentonite coated suspension insulators. In these tests the insulators were stressed at constant voltage (0, 10, and 15 kV) under conditions of 8 mph wind and 9% salt fog for various time intervals (20, 40, 60, and 80 minutes) After this exposure the bentonite and salt were washed off to determine the contaminant distribution. Various voltages were used to see if there was any noticeable effect of voltage on the final distribution. In five tests the insulator flashed over before the end of the test and was removed and washed without being exposed for the intended time.

The insulator was divided into 3 separate regions for washing, the top, a bottom inner region, and a bottom outer region. Figure 4.1 shows these regions. The respective areas are 544, 188, and 696 cm^2. In almost every test the dry zone occurred on the first skirt. Thus the bottom inner region usually included the entire dry zone. This is worth noting since a salt crust usually formed in the dry zone. The salt density is therefore able to reach much higher values since in the wet regions the amount of salt is limited by the amount of water the surface can hold without dripping.

Every effort was made to achieve repeatable results. The insulators were sprayed with bentonite as repeatably as possible with the hand sprayer. Before applying fog the insulator was placed in the fog chamber for 10 minutes with the wind on to allow it to reach ambient temperature. Before each day's tests the fog was run for about 5 minutes to humidify the chamber so that the initial conditions on the first test would be the same as for later tests.

The insulator was then put in the chamber as the center unit of a 3 unit string as shown in Fig. 4.3. After 10 minutes of wind the voltage was applied, followed about a minute later by the fog. Test time was measured from the turning on of the fog. After the desired exposure time had been reached, the voltage and fog were turned off, and the insulator was removed and hung up to dry. In one test the insulator was dried under voltage. Time limitations prevented drying all insulators under voltage which would be a more realistic approximation of field conditions. A typical leakage current curve is given in Fig. 4.8. Only rarely were there scintillations during these tests. Since some of the tests lasted 80 minutes with no flashover, the interpretation of Section 4.2 that dry zones wide enough to sustain the entire voltage are forming is reinforced.

The data from these tests is presented in Table 4.4. It will be noticed that the inner bentonite level is about twice the outer. This resulted from the spraying technique. The ratio is relatively constant from test to test, and in any case the distribution resembles that found on naturally contaminated insulators. The salt densities show a scatter too large to be accounted for by experimental error in determining the deposit density. Probably this is in some degree due to the difficulty in obtaining a repeatable bentonite coating.

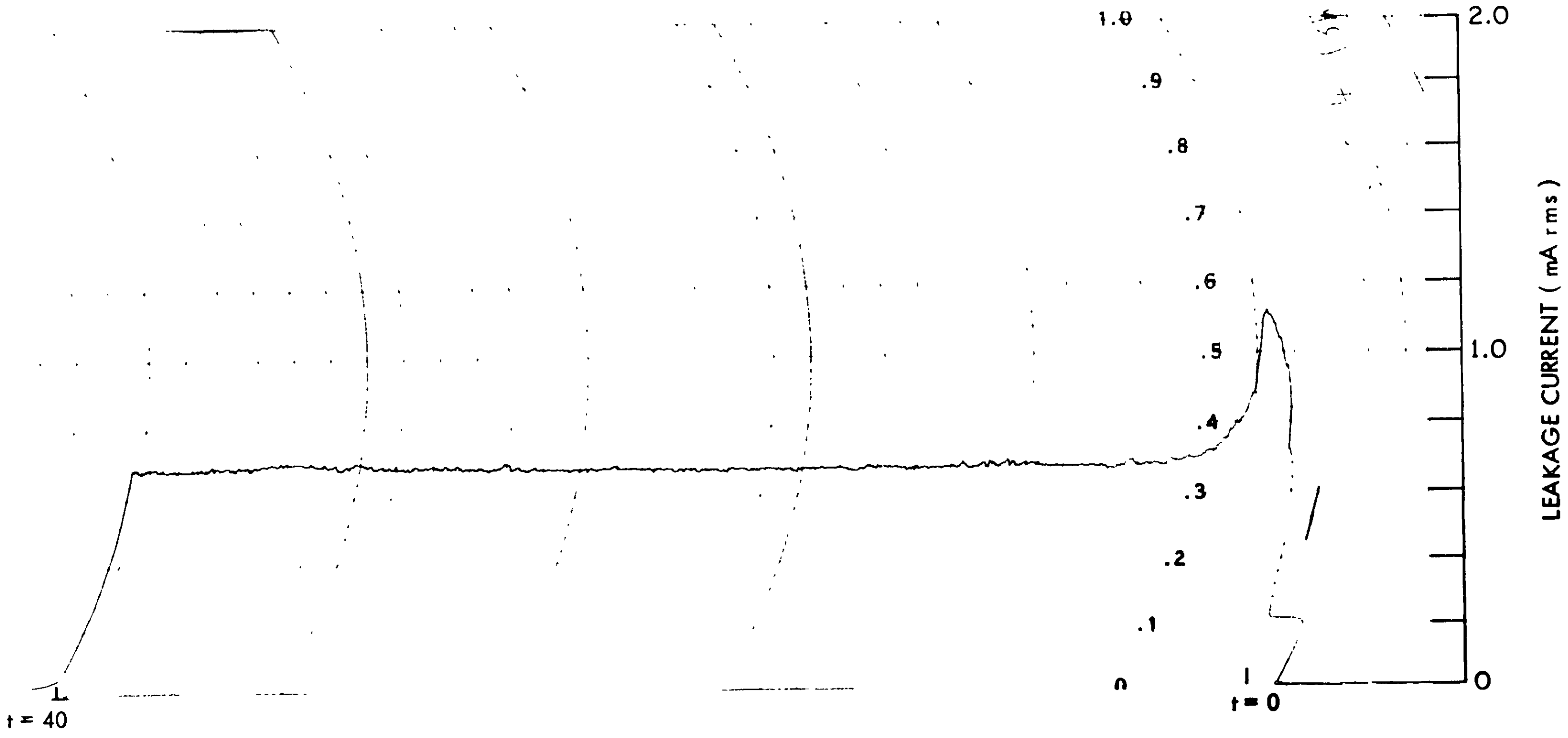


Fig 4.8 Typical leakage current behavior for bentonite coated insulators. Test 18 of Table 4.4, 15 kV, 9% fog

Table 4.4

Permeation and Deposition Test Results

			Salt Bentonite (mg/cm^2)				
Test No.	Voltage (kV)	Time* (min)	Top	Bottom Total	Bottom Inner	Bottom Outer	Dry Zone Location(s)
1	0	20	0.164	0.111	0.181	0.092	1st skirt
			.22	.41	.69	.33	
2	0	40	.20	.22	.23	.22	"
			.15	.20	.37	.16	
3	10	20	.160	.182	.30	.151	"
			.24	.38	.64	.32	
4	10	25F	.29	.23	.29	.21	1st skirt, cap, & irregular strips
			.44	.79	1.49	.60	
5	10	36F	.34	.25	.33	.23	1st skirt, cap, & irregular strips
			.37	.53	.85	.45	
6	10	40	.24	.33	.47	.29	1st skirt
			.44	.49	.74	.42	
7	10	60	.26	.46	.94	.33	"
			.11	.41	.80	.30	
8	10	60	.29	.46	.78	.37	"
			.42	.43	.74	.35	
9	10	60	.42	.57	1.36	.35	"
			.53	.93	1.38	.80	
10	10	80	.25	.50	1.23	.30	"
			.13	.15	.41	.10	
11	15	20	.171	.170	.37	.115	"
			.18	.32	.43	.29	
12	15	21.4F	.178	.182	.34	.138	"
			.11	.03	.05	.03	
13	15	27.2F	.186	.22	.48	.154	"
			.09	.14	.27	.10	
14	15	40	.171	.27	.48	.22	"
			.04	.05	.10	.04	
15	15	40	.28	.35	.65	.26	"
			.17	.15	.27	.11	
16	15	40	.092	.35	.57	.30	"
			.02	.18	.27	.16	
17	15	40	.25	.30	1.03	.21	"
			.17	.24	.37	.20	
18	15	40	.193	.35	.65	.27	"
			.17	.34	.48	.30	
19	15	40	.29	.68	2.13	.29	"
			.20	.35	.59	.29	

Table 4.4 (Continued)

Test No.	Voltage (kV)	Time* (min)	Top	Bottom Total	Bottom Inner	Bottom Outer	Dry Zone Location(s)
20	15	40	.32	.44	.98	.27	irregular
			.37	.42	.58	.37	
21	15	40	.32	.34	.75	.23	1st skirt
			.79	.50	.91	.39	
22	15	40**	.27	.58	1.35	.36	"
			.11	.52	.91	.42	
23	15	40	.22	.41	.98	.35	irregular
			.66	1.22	1.75	1.08	
24	15	40	.43	.64	1.67	.36	1st skirt
			1.08	1.48	2.39	1.23	
25	15	41.6F	.27	.48	1.19	.27	"
			.13	.15	.21	.13	
26	15	42^{+}	.32	.76	.67	.78	2nd skirt & band around cap
			.61	.83	1.28	.70	
27	15	60	.55	.41	.89	.27	1st skirt
			.24	.32	.58	.24	
28	15	60	.33	.48	.90	.36	"
			.73	.71	1.12	.60	
29	15	80	.30	.60	1.56	.35	"
			.18	.31	.64	.22	
30	15	80	.55	.94	2.71	.46	"
			.94	1.06	1.70	.89	

* F indicates flashover

\+ Voltage inadvertantly left on two extra minutes

** Insulator dried under voltage

Differences in texture were sometimes apparent to the eye, some coatings appearing coarse and grainy, and others appearing smooth and uniform.

However, despite the scatter, there are some general conclusions that can be drawn. For one thing, the concentration of salt in the inner region is greater than in the outer region with the single exception of Test 26. This test was the only one where the dry zone formed on the 2nd skirt, which is partly in the outer washing region. The conclusion is that the salt tends to concentrate in the dry zone, regardless of where that may be. This agrees with the observation in some early exploratory tests that salt crusts always formed at the dry zone, wherever it was. The concentration mechanism would appear to be surface permeation. Nevertheless strong electric fields exist at the dry zone and may affect the deposit buildup.

An effort is made in Fig. 4.9 to systematically plot the build-up of salt in the center region. Only the tests where the dry zone was in the center region were included. Where more than one test was done for a given condition, the data were averaged, the number of points averaged being shown in parentheses. It can be seen that the buildup of deposits seems to increase as voltage increases. This could mean several things:

1) Due to increased ohmic heating the water may evaporate faster at higher voltages, leaving behind the dissolved salt at a faster rate.

2) Higher electric fields could attract salt fog particles at a faster rate.

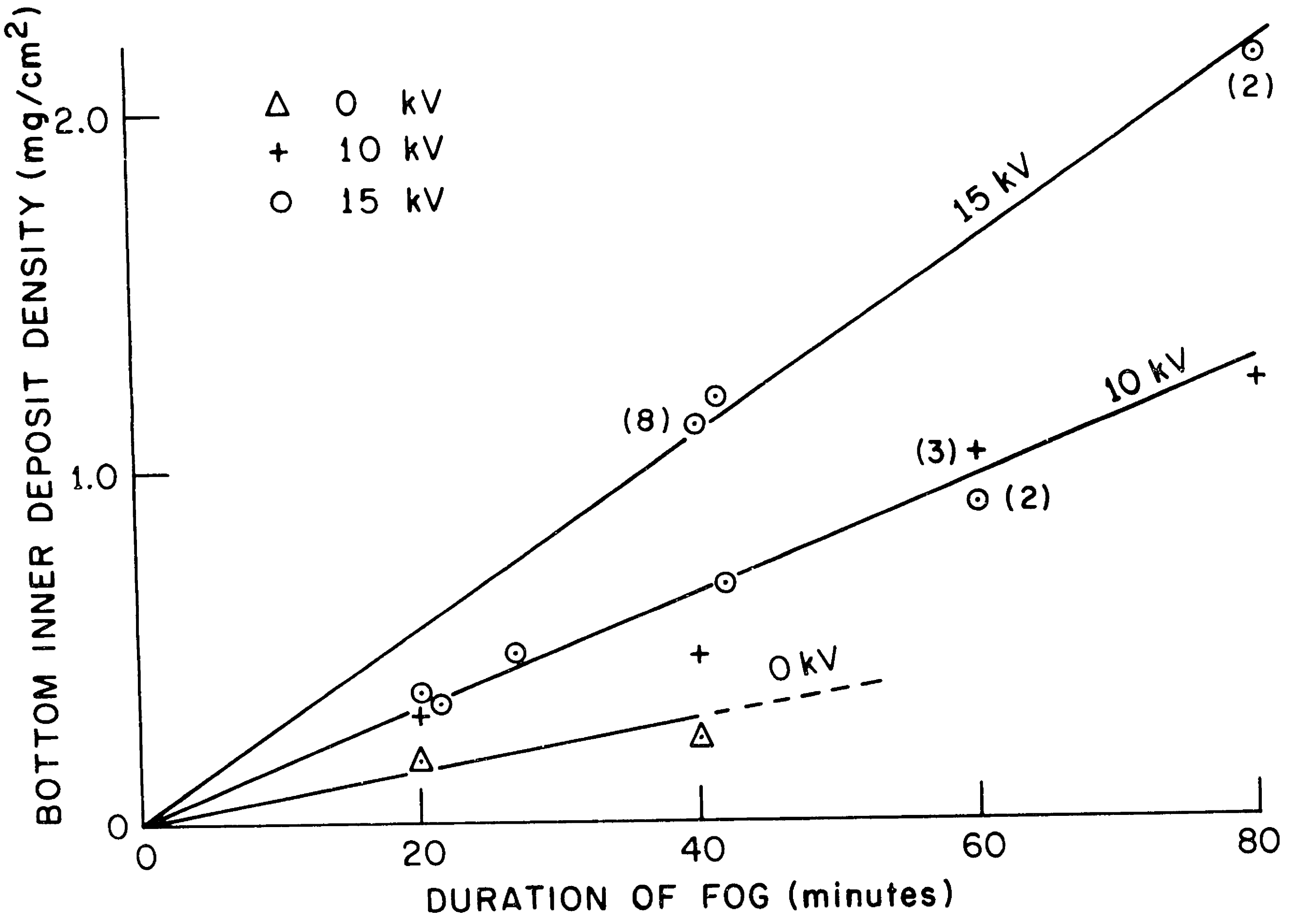


Fig. 4.9 Salt buildup in the bottom inner region as a function of time. The results were averaged when possible, the number of points averaged being shown in parentheses.

3) At higher voltages the electric field would exert a greater force on the liquid at the dry zone boundary, pulling it into the dry zone at a faster rate.

The data is unfortunately not precise enough to quantitatively support any one viewpoint. The only conclusion is that increasing the voltage increases the buildup of contaminant in the dry zone. The best way to resolve this question would be to do carefully controlled tests on specimens of simple geometry.

4.6 Tests on Field Contaminated Insulators

One of the goals of this thesis was to find a test procedure which can determine how close insulators removed from service are to flashing over. A reliable test procedure would provide useful feedback for string replacement programs. Furthermore, it was considered important to find out how naturally contaminated insulators performed in the M.I.T. fog chamber.

Fortunately it was possible to obtain field contaminated insulators from the Ohio Power Co. and the Wheeling Electric Co., two of AEP's operating companies. Insulators from 5 different strings were available for testing. These strings are characterized briefly in Table 4.5. String A was removed from a tower on which another phase had flashed over. The other strings were merely removed from contaminated areas. There were also a few other field insulators lying around the lab left over from McElroy's investigation which were used in some preliminary tests.

Several factors could affect the flashover voltage of field

Table 4.5

Description of Field Contaminated Insulators Tested

String Designation	Total number of units available for testing	Type	Known History
A	2	5 3/4 x 10" Locke 20,000 lb	Tower 205, left bottom, ground end, Muskingum-Tidd 345 kV line
B	6	5 3/4 x 10" Locke 20,000 lb	Tower 213, right bottom, Muskingum-Tidd 345 kV line, treated with silicone grease
C	6	5 3/4 x 10" Locke 30,000 lb	Tower 213, left bottom, Muskingum-Tidd 345 kV line ungreased
D	6	5 x 10" OB 15,000 lb	From Wheeling Electric Co., caps painted
E	5	5 3/4 x 10" (no visible markings)	From Wheeling Electric Co., metal parts highly corroded

Equivalent Salt Density (mg/cm^2)

Insulator	Top	Bottom Total	Bottom Inner	Bottom Outer
A2	0.044	0.040	0.062	0.034
B		(greased)		
C4	0.170	0.45	0.56	0.42
D4	.048	.0077	.0142	.0059
E3	.0076	.0085	.0169	.0063

contaminated insulators. These include condensation, fog conductivity, wind, ambient temperature, and non-linear voltage distribution along the string. Non-linear distribution effects could not be studied in detail because of voltage limitations, and it was not considered worth the trouble to change the ambient lab temperature. However the effects of condensation, fog conductivity, and wind were investigated.

Tests were first done using a distilled water fog since it was felt that the use of salt fog would alter the nature of the surface contamination, making it impossible to draw any firm conclusions. Also Kawai (1970 d) has been able to obtain flashover on field contaminated insulators in a steam fog test near the voltage at which they had flashed over in service.

Test 10 of Table 4.7 was the first to be done. The insulator was exposed to distilled water fog and an 8 mph wind. The voltage was gradually raised to 25 kV without incident although a few small scintillations occurred. After 161 minutes of fog the fan was turned off. Flashover occurred about one minute later with no change in voltage. This suggested that the wind may have been inhibiting flashover. A second test (#11) was done on the same insulator with the fan being turned off periodically for 5 minutes at a time. Flashover occurred at 19 kV, 10 seconds after the fan had been unplugged. From this it was concluded that wind somehow inhibited flashover. Johnson et al. (1968) remark that field observers noticed an immediate decrease in discharge activity whenever the wind exceeded about 5 mph.

A test (#12) was then run with no wind at all. In this case flashover occurred at 20 kV, or about the same voltage as with alternating wind and no wind. A second test (#13) was run with no wind, but by 140 minutes there had been no flashover. The voltage was raised rapidly (∿1 kV/sec) and flashover occurred at 24 kV. Inspection of the insulator revealed that the bottom was quite dry, and the insulator was noticeably warm to the touch. Apparently the leakage current warmed the insulator and prevented moisture buildup. Wind is probably necessary to prevent any such drying effect.

Accordingly a test procedure was adopted in which wind was applied most of the time with periodic intervals of no wind to give flashover a chance to occur. The standard procedure eventually adopted is summarized in Table 4.6. To get the insulator wet it is first exposed to fog and wind for 25 minutes at some low voltage, usually around 15 kV. The fan is then turned off and restarted 4 minutes later. At 30 minutes the voltage is raised 2 kV and the insulator is exposed to wind and fog for 15 minutes when the wind is again turned off. This is repeated until flashover occurs or until about 2 hours have passed. In the latter case, the voltage is raised 1 kV or so every minute or so until flashover does occur. The one minute interval between fan on and voltage raising is to separate the two effects, since the sudden impact of fog droplets at fan turn-on while the voltage is being raised could lead to premature flashover. The test procedure was designed to avoid flashover during voltage

Table 4.6

Standard Test Procedure for Field Contaminated Insulators

Time (minutes)	Event
-10	15 kV applied,[*] fan on
0	Fog on
25	Fan off
29	Fan on
30	17 kV
45	Fan off
49	Fan on
50	19 kV
65	Fan off
69	Fan on
70	21 kV
85	Fan off
89	Fan on
90	23 kV
105	Fan off
109	Fan on
110	25 kV
125	Fan off
129	Fan on
130	Raise voltage until flashover

[*] The initial voltage was sometimes varied in order to obtain flashover in a reasonable time.

Table 4.7

Test Results for Field Contaminated Insulators

Test	Insulator	Weather Cycle	Fog	Wind	Flashover Voltage*	Exposure Time
1	A1	1	dist.	on/off	28	134.0
2	A1	2	dist.	on/off	39	145.2
3	A1	3	1%	on/off	17	65.8
4	B1	1	dist.	on/off	25W	130.0
5	B2	1+	dist.	none	35W	85.5
6	B3	1	1%	on/off	40	128.9
7	C1	1	dist.	on/off	25W	130.0
8	C2	1+	dist.	on/off	25W	60.0
9	C3	1+	dist.	none	35	85.5
10	C3	2	1%	on/off	19	69.1
11	D1	1	dist.	on	25	162.2
12	D1	2	dist.	on/off	19	65.2
13	D1	3	dist.	none	20	90.2
14	D1	4	dist.	none	24	140.0
15	D1	8	dist.	on/off	25	110.5
16	D2	1	dist.	on/off	23	101.6
17	D2	2	dist.	on/off	19	65.4
18	D2	3+	dist.	none	19	23.1
19	D2	7	dist.	on/off	19	54.8
20	D1,D2	5,4	dist.	none	32	50.2
21	D1,D2	6,5	dist.	none	40	49.7
22	D1,D2	7,6	dist.	none	40W	58.0
23	D3	1	1%	on/off	17	75.2
24	D5,D6	1,1	1%	on	40W	58
25	E1,E4	1,1	1%	on	40W	50
26	E5	1	dist.	on/off	40	122.6
27	E5	2	1%	on/off	19	77.8
28	E6	1	dist.	on/off	35W	142.0

*W indicates withstand

+Insulator cooled to about 0°C before test raising since voltage raising does not reflect field conditions.

In order to see if condensation could lower the flashover voltage, a test (#17) was run on insulator D2. In this test the insulator was first cooled to -2.5°C. It was then hastily placed in the fog chamber, and the fog and voltage were turned on. The chamber ambient was 23°C. No wind was used in order to keep the insulator cool as long as possible. The voltage was held at 15 kV for 15 minutes and then raised 1 kV every minute until flashover at 19 kV. This is about the same flashover voltage as the two previous tests on this insulator, 23 kV and 19 kV respectively. Apparently condensation has no strong effect. This is probably because the fog is so dense to begin with that the extra deposition due to condensation makes no difference. In other words, the fog chamber already provides worst case conditions without condensation. Of course in the field, where fog is less dense, condensation could have a stronger effect.

Some tests were done with salt fog in order to see how much a conducting fog would lower the flashover voltage. McElroy et al. (1970) found that naturally occurring fogs can have up to about a 1% equivalent salt concentration. Therefore a 1% NaCl fog was selected for these tests. For string A the salt fog lowered the flashover voltage from 28 kV to 17 kV. String C was lowered from 35 kV to 19 kV, string D from 19 kV to 17 kV, and string E from 40 kV to 19 kV. Thus conducting fog can materially lower the flashover voltage. All of these salt fog tests were run with the standard wind on/off procedure of Table 4.6.

The effect of a non-uniform voltage distribution along a string was touched on briefly. Unfortunately voltage limitations prevented testing more than 2 units in series. In these tests the wind was always left off since at the higher voltages it was judged too dangerous to approach the chamber to operate the fan. The two test insulators were at the top end of a 3 unit string with the bottom unit shorted internally. In the first test (#19) the two units flashed over at 32 kV, i.e., 16 kV per unit, which is 3 kV below the single unit flashover voltage. In the second test (#20) flashover occurred at 40 kV which is about double the single unit voltage. In the third test (#21) the 2 units withstood 40 kV, the maximum safe voltage. In the first test only the top unit scintillated, while in the second test both scintillated. The unequal sharing of voltage thus decreased the flashover voltage by 8 kV. Since the third test was a withstand at 40 kV, the insulators were tested again individually to see if washing had occurred. One insulator flashed over at 19 kV, the other at 25 kV (Tests 14 and 18). Since these two unit tests were done with no wind, further tests should be done on 2 unit strings using the wind on/off method to see if the flashover voltage is lowered.

It should be noted in passing that the greased units performed quite well despite a very dirty appearance, withstanding 35 kV.

It is puzzling that even on heavily contaminated insulators flashover always occurred in the neighborhood of 20 kV, while normal operating voltage is below 14 kV per unit. Since the test conditions are supposed to be more severe than natural conditions, it is difficult to see why lower voltages were not obtained. According to a discussion by Reed (Woodson and McElroy, 1970 b) test results from a single unit can not be extrapolated to a string. This is because some insulators may not have dry zones, causing an unequal sharing of voltage. This is confirmed to some degree in Test 19 where a 20% reduction in flashover voltage resulted from unequal voltage distribution. The tentative conclusion based on these tests is that tests on full scale strings are necessary to determine the contamination state of field insulators. It might be possible to find a "reduction factor" to predict string behavior from a single unit but this would be risky. Conducting fog may also play a role in reducing the flashover voltage, but only full scale tests could determine the relative importance of fog conductivity and non-uniformity of voltage distribution.

Certain AEP operating experiences seem to indicate the non-uniform voltage distribution is the decisive factor. In some cases flashover will occur and reclosing will be unsuccessful. After a 15 or 30 minute wait the line will again support voltage. Flashover then occurs an hour or so later necessitating another wait. Presumably during these waits the insulators become completely wet. When voltage is re-applied the voltage is then distributed uniformly and flashover does not occur. However in a little while a non-uniformity will develop and flashover again occurs.

A more complete discussion of the tests on field contaminated insulators can be found in the thesis of Ayers (1971).

4.7 Summary and Conclusions

Standard suspension insulators were exposed to a variety of conditions to determine what factors affect their contamination performance. The results are summarized below:

1) In tests on single insulators with bentonite coatings wide stable dry zones formed. These were sometimes wide enough to withstand practically the entire applied voltage, completely suppressing discharging and preventing flashover. Thus, when testing single units, only a very light coating of bentonite should be used. In testing strings probably the non-uniform voltage distribution would prevent the dry zones from completely stopping discharging.

2) Tests were done at various voltages and fog salt concentrations on Photoflo coated insulators. As expected, increasing either the voltage or the salt concentration lowered the time to flashover. An apparent discontinuity in the 9% fog results was tentatively attributed to a breakdown mechanism where the electric field pulls a filament of water from the wet region into the dry zone, triggering flashover.

3) The effect of glaze weathering was investigated by exposing a clean and a weathered insulator to salt fog. They flashed over at about the same voltage except for one discrepancy. However there was a substantial difference in the initial rates of current rising faster on the weathered insulator. This was attributed to less bead formation on the weathered insulator. The fastest initial current rise occurs on Photoflo or bentonite coated insulators where beading cannot occur.

4) Tests were done to determine what causes the concentration of salt in the region around the pin during salt fog tests. It was shown that the tendency for the salt to concentrate near the pin increases as the voltage is raised. Several reasons were proposed to explain this behavior, but the actual cause could not be determined from the data.

5) In testing field contaminated insulators it was found that wind suppressed discharge activity to some degree. This confirms certain field observations.

6) Condensation did not lower the flashover voltage of field contaminated insulators in distilled water fog tests. Apparently the fog is so dense that additional deposition due to condensation makes little difference.

7) Replacing distilled water fog with 1% salt fog substantially reduces the flashover voltage of field contaminated insulators. This suggests that conductive fog greatly increases the risk of flashover of outdoor insulation.

8) When two field contaminated insulators were tested in series unequal voltage sharing led to a 20% reduction in flashover voltage. This occurred when only one unit developed a dry zone. The only reliable way to estimate the contamination state of insulators removed from service is to test strings rather than one unit.

CHAPTER 5

TESTS ON SPECIAL INSULATORS

5.1 Introduction

Chapter 4 dealt with the contamination performance of the standard 5 3/4 x 10" suspension insulator. This chapter considers what happens when the standard unit is modified in order to increase its resistance to flashover. Section 5.2 describes the effects of varying the geometry and Section 5.3 discusses the effect of semiconducting glazes.

5.2 Tests on Special Insulator Geometries

Over the years many different types of so-called "fog-units" have been developed to combat contamination flashover. These are insulators whose shape is varied from that of the standard unit in an attempt to improve performance. Some of the more important ways of doing this are listed below:

1) Increasing the creepage path on the protected underside where the insulator remains dryest,

2) Increasing the creepage path on the exposed outer surfaces where the washing action of rainfall prevents thick deposit buildup.

3) Using perfectly smooth horizontal surfaces for increased cleaning by wind, or

4) Using long drooping vertical surfaces which presumably hold less water.

The merits of such modifications have long been debated. Probably no single type is best for all regions, and the choice of insulation should reflect local conditions. The paper of Taylor (1948) gives an interesting account of early attempts to find better shapes.

In order to investigate the influence of shape, a number of tests were run using the 7 different insulators shown in Fig. 5.1. These insulators clearly cover a wide shape range. The essential geometrical parameters of these insulators are given in Table 5.1. The insulators might be briefly characterized as follows:

Type 1 - Standard Suspension
Type 2 - Smooth disc for cleaning by wind or for use in tension
Type 3 - Large sheltered interior region for use along sea coasts
Type 4 - External creepage path for improved rain washing
Type 5 - High creepage type with creepage on bottom
Type 6 - Oversize unit
Type 7 - Light weight standard unit.

Insulators 2 through 7 were first tested using the bentonite coating method. The insulators were given a light ($\sim$0.04 mg/cm^2) bentonite coating and then exposed to 9% salt fog and an 8 mph cross wind while stressed at 15 kV. The usual test arrangement was used (Fig. 4.3) with the test insulator as the center unit of a 3 unit string. Unfortunately there was only one of each special type available and standard suspension units had to be used as dummies, the exception being #5 which had clevis fittings and was tested with no unit below it. Thus the airflow conditions in these tests may

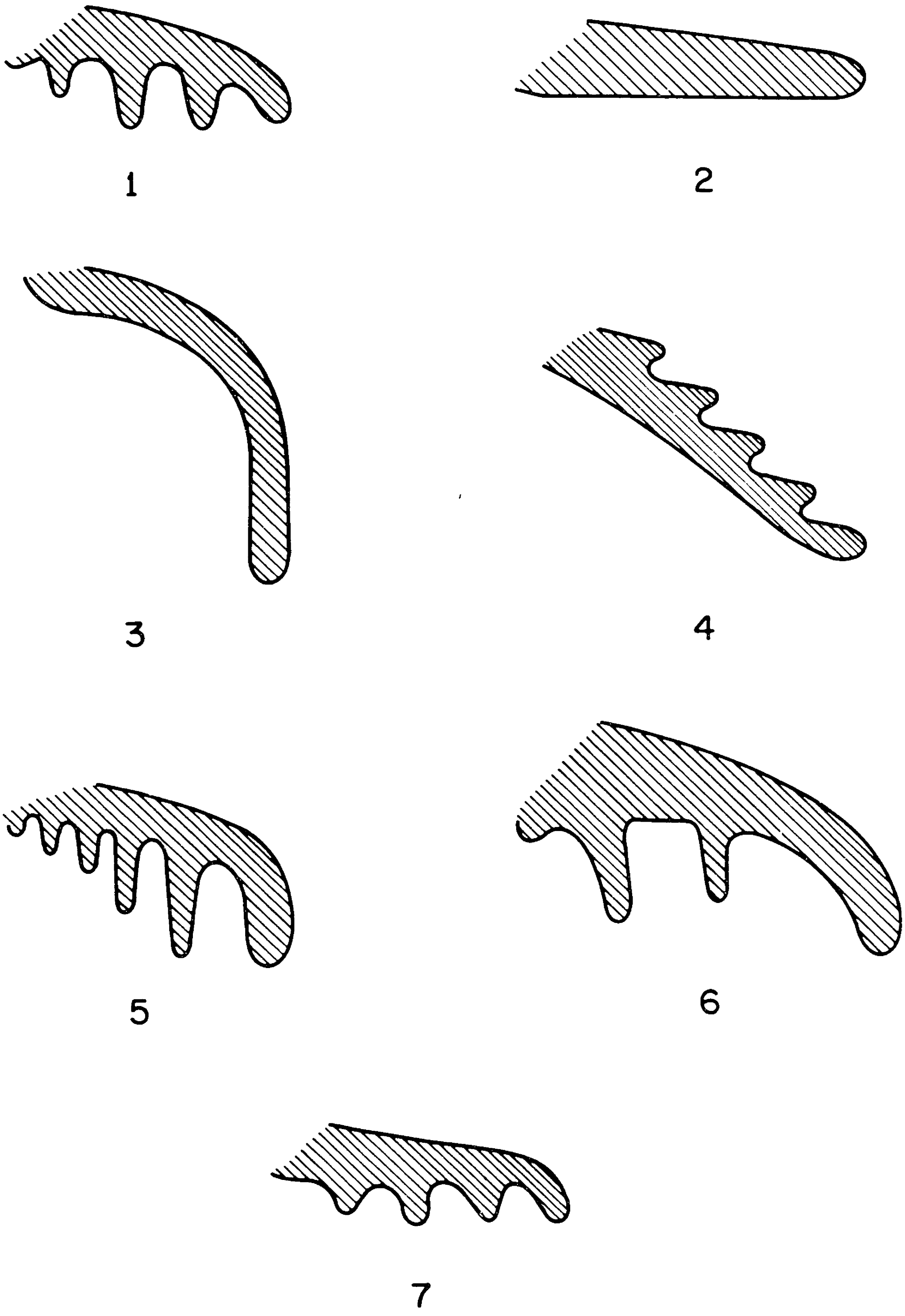


Fig. 5.1 Insulator Shapes Tested

Table 5.1

Geometric Parameters of Tested Insulators

Type	Inches Diameter	Inches Creep	Creepage (cm.) Top	Bottom	Total	Form Factor
1	10	12.0	10.5	20	30.5	0.78
2	12	11.4	11	14	25	.53
3	9 1/2	13.7	16.4	18.5	34.9	.80
4	12	14.3	20.3	16	36.3	.87
5	10 1/2	17.0	11.7	31.6	43.3	1.04
6	13 1/2	17.5	16.5	28	44.5	.87
7	10	11.5	11.2	18	29.2	.75

differ somewhat from strings of entirely one type.

Four separate series of tests were run on these 6 insulators. The first three were largely exploratory. The fourth series, summarized in Table 5.2 was an attempt to test all 6 insulators under identical conditions so that they could be ranked in order of merit. This last series consisted of a maximum exposure time of two one hour weather cycles. If flashover did not occur at the end of the 2nd cycle the voltage was raised in 1 kV steps every two minutes until it did occur, the voltage of flashover being noted in the table. This voltage needed for flashover was the basis for ranking those insulators which lasted the full 2 hours.

It is informative to correlate this performance ranking with geometric variables such as creepage path and diameter. The simplest way of doing this is to make use of Spearman's coefficient of rank correlation. This coefficient is useful when ranked data are to be compared, and is simply an estimate of the degree of correlation between two rankings. Thus for example if the ranking of insulators according to the performance corresponded exactly to the creepage path ranking, the correlation coefficient would be +1.0. If there were no relation at all between the two rankings, the coefficient would be zero, and if the rankings were exactly opposite it would be -1.0. The method of computing this coefficient is given in Appendix 2.

Table 5.3 gives the correlation between performance and various other quantities for the bentonite tests.

Table 5.2

Test Results for Bentonite Coated Insulators

Insulator No.	Time to Flashover (min.)*	Bentonite Top (mg/cm^2)	Bentonite Bottom (mg/cm^2)	Salt Top (mg/cm^2)	Salt Bottom (mg/cm^2)
2	33.7	0.08	0.06	0.29	0.19
3	128.2 (20kV)	.06	.08	.36	.34
4	119.8	.17	.03	.73	.55
5	127.5 (19kV)	.17	.06	.47	.31
6	122 (16kV)	.22	.09	.67	.32
7	50.4	.09	.06	.50	.37

*Figures in parentheses are the voltages required for flashover if it did not occur in two hours.

Table 5.3

Correlation between performance and:	
Bottom salt deposition rate	- 0.94
Bottom creepage distance	+ .77
Form factor	+ .66
Total creepage distance	+ .60
Bottom area	+ .60
Top creepage distance	+ .49
Diameter	- .43

These are listed in decreasing order of the absolute value of the correlation coefficient. A negative sign indicates inverse correlation, e.g., the greater the salt deposition rate, the worse the performance. At the 95% confidence level a coefficient of magnitude greater than 0.83 is statistically significant, while at the 99% level, 0.94 is significant. Thus at the 99% level only the correlation with salt deposition rate is statistically significant. In other words, there is only a 1% chance that such a high correlation could occur by chance.

The bottom salt deposition rate was determined by taking the total salt density for the four series and dividing by the total exposure time. The units are mg. of salt per square centimeter per hour. It is simply a measure of how fast the salt builds up on the insulator undersurface. The values obtained are listed in Table 5.6 later in this section.

Thus performance in this preliminary test series seems to correlate most strongly with the protective effect of the insulator; the slower the salt buildup, the better the performance. The next most strongly correlated quantity would be the creepage distance on the bottom. These results certainly seem to agree with common sense. A complete summary of these tests with leakage current records may be found in the thesis of Frederick (1970).

However sensible the conclusions may be, the test results are nevertheless suspect for the reasons indicated in Section 4.2. In many tests scintillations did not occur. In particular, in the last series, units # 3, 5, and 6 did not scintillate, and these were the ones which required voltage raising after 2 hours.

In order to have an additional measure of performance, insulators 1 through 7 were tested using only a Photoflo coating as described in Section 4.3. They were subjected to the same 9% fog and 8 mph wind and stressed at the same voltage (15 kV) as in the bentonite tests.

The results are given in Table 5.4. It can be seen that there is a certain degree of variability in the results. This variability is most likely due to factors connected with the application of the Photoflo. As mentioned in Section 4.3, it is vital to achieve a complete coating. The student preparing the insulators for these Photoflo tests was not a particularly skillful lab technician and apparently had some trouble achieving a repeatable coating. This interpretation is borne out by the fact that bottom salt densities of about 0.2 mg/cm^2 were required to flash over unit #1 while in

Table 5.4

Test Results for Photoflo Coated Insulators

(15 kV, 9% NaCl Fog)

Insulator No.	Test No.	Time to Flashover (min.)*	Salt Density (mg/cm^2)	
			Top	Bottom
1	1	30(16 kV)	0.094	0.31
	2	20.4	.111	.22
	3	21.6	.100	.23
	4	29.3	-	-
	5	27.2	.109	.24
	6	23.8	.107	.27
2	1	13.7	.069	.123
	2	30(?**)	.125	.24
	3	26.7	.107	.24
	4	26.3	.111	.22
3	1	30(20.2 kV)	.122	.098
	2	14.9	.070	.076
	3	14.3	.068	.075
4	1	11.4	.093	.151
	2	18.9	.136	.169
5	1	30(19.4 kV)	.124	.138
	2	45(18.8 kV)	.125	.179
	3	60(21.6 kV)	.110	.124
6	1	30(16.6 kV)	.102	.131
	2	30(19.0 kV)	.091	.112
7	1	26.1	.098	.20
	2	21.2	.120	.120

*If flashover did not occur by the time indicated the voltage was raised 200 volts every second until it did occur. The voltage at flashover is indicated in parentheses.

**Voltage at flashover not recorded.

Section 4.3, 0.1 mg/cm^2 was typically required. Correspondingly the exposure time was greater for this particular insulator. However, since all insulators in Table 5.4 were prepared by the same student, the relative performance of the various types should remain pretty much unchanged.

Once again the insulators may be ranked in order of merit, using the minimum time to flashover, or the voltage required for flashover as the measure of performance. The rankings obtained by the two test methods are compared in Table 5.5.

Table 5.5

Insulator	Rank in Bentonite Tests	Rank in Photoflo Tests
1	(not tested)	4
2	6	6
3	1	5
4	4	7
5	2	1
6	3	2
7	5	3

Based on the combined results of both test methods it would seem that insulator 5, the high creepage fog type, is best, with insulator 6, the oversize unit, coming in second. The only glaring discrepancy between the two rankings is with #3, the fog bowl, which ranked best for bentonite but only fifth best for Photoflo.

As mentioned earlier this is due to formation of a wide, stable dry zone in the bentonite tests which prevented scintillations.

Table 5.6 shows how the rankings with both test methods correlate with various quantities. The average of the two correlations is also given. Using this average, the strongest correlation is with the creepage path on the bottom of the insulator. Deposit rate and bottom area also correlate well with performance but not as strongly. The high correlation with area is to be expected from the high bottom creepage path correlation since increasing bottom creeppage tends to increase the bottom area.

Thus based on the combined results, bottom creepage distance is probably the shape variable most closely related to performance in these tests. This is hardly news to the insulator manufacturers who have been putting most of the creepage path on the bottom for years. Of course, there is a limit to how much creepage path can be obtained for an insulator of given diameter. If the petticoats are too deep relative to their spacing sparkover can occur across the edges, effectively shorting out large segments of creepage path. Furthermore, under heavy contamination conditions, deep narrow grooves can become clogged with dirt.

Above all it must be remembered that these test results were done with a highly conducting fog, and the conclusions thus apply only to sea coast regions or other areas where fog conductivity could be an important factor in flashover. Some insulators are deliberately constructed to have a large fraction of creepage path

Table 5.6

Correlation of Both Test Rankings
with Various Quantities

Correlation of Performance with:	Bentonite Test Method	Photoflo Test Method	Average Correlation
Bottom leakage distance	+0.77	+0.86	+0.82
Bottom deposition rate	- .94	- .50	- .72
Bottom area	+ .60	+ .82	+ .71
Form factor	+ .66	+ .50	+ .58
Total leakage distance	+ .60	+ .46	+ .53
Diameter	- .43	0.00	- .22
Top leakage distance	+ .49	- .11	+ .19

exposed for washing by rain. These types are no doubt effective in regions where a dangerous buildup of deposit requires longer than the maximum interval between rainfalls. The merits of this type, similar to unit #4, cannot be evaluated with the tests of this section since washing was not simulated. Only by contaminating these insulators under actual service conditions can a realistic evaluation of the external creepage types be made.

Salt deposition rates were computed for both test series. The rate is computed by dividing the sum of the salt deposits for all tests on a given insulator by the sum of the test times. This gives the salt buildup rate in mg/cm^2 hr. Table 5.7 compares the rates obtained for the 2 test methods.

As can be seen, the general trends are about the same for the two methods, with the flat disc (#2) having the poorest protective effect, and the high creepage fog type (#5) having the greatest protective effect. For several reasons it is felt that the rates obtained with the bentonite coated insulators are superior to the Photoflo results. One reason is that the Photoflo coating will hold less water, with the excess dripping off. A more important reason is that, as mentioned earlier, the student conducting the Photoflo tests wasn't too good at lab work, in strong contrast to the student doing the bentonite tests. A measure of the error for the Photoflo tests was obtained on Test 1 on insulator #3. In this test the insulator was washed a second time. An additional 20% of salt was obtained from the bottom and 15% from the top. On insulators with

Table 5.7

Bottom Salt Deposition Rates for the

Two Test Methods

(mg/cm^2 hr)

Insulator No.	Bentonite Test Method	Photoflo Test Method
1	0.64*	0.62
2	.65	.51
3	.14	.25
4	.33	.63
5	.085	.20
6	.15	.24
7	.37	.41

*Insulator No. 1 was not tested with the bentonite method. The rate given here was calculated from the 11 forty minute tests at 15 kV in Table 4.3.

convolutions the amount missed would be even more. Only the salt from the first washing was used in Table 5.4 since the other insulators were washed just once. It is difficult to see a thin salt coating, and spots are easy to miss while washing. With the somewhat tenacious bentonite, the surface must be gone over several times with the wet brush, assuring that all the salt is removed.

It was found that the salt deposition rate is closely related to the sum of the heights of the skirts on the bottom of the insulator. This is reasonable since either increasing the number or the depths of the skirts should increase the protective effect. The method of computing the sum is shown in Fig. 5.2 and the relation between this sum and the salt deposition rate is plotted in Fig. 5.3. The more trustworthy bentonite coated test results were used. The effect of shape on the deposition rate has been studied to some extent by Böhme and Zeh (1967).

5.3 Tests on Insulators with Semiconducting Glazes

One of the best prospects for solving the contamination problem seems to be the use of insulators with semiconducting glazes. The idea is an old one, with several patent applications having been made in the 1920's (Taylor, 1948). There are several possible mechanisms by which such a glaze could inhibit flashover. Moran and Powell (1971) for example list several:

1) The glaze linearizes the voltage stress along the insulator surface, preventing local stress concentrations from forming.

2) The heat dissipated by the current through the glaze warms the surface, preventing moisture buildup.

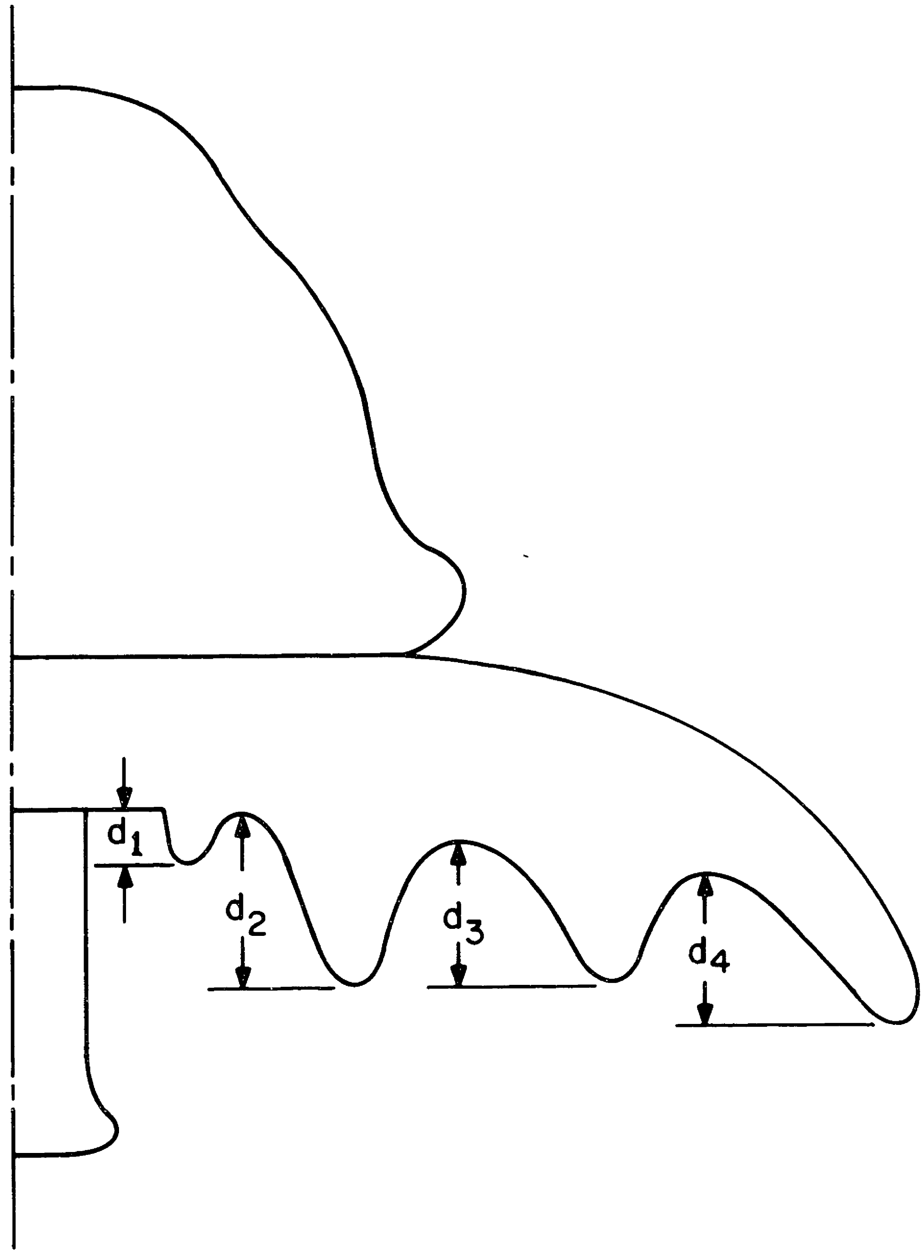


Fig. 5.2 Method of computing the sum of skirt depths for a typical insulator. In this case the sum is equal to $d_1 + d_2 + d_3 + d_4$.

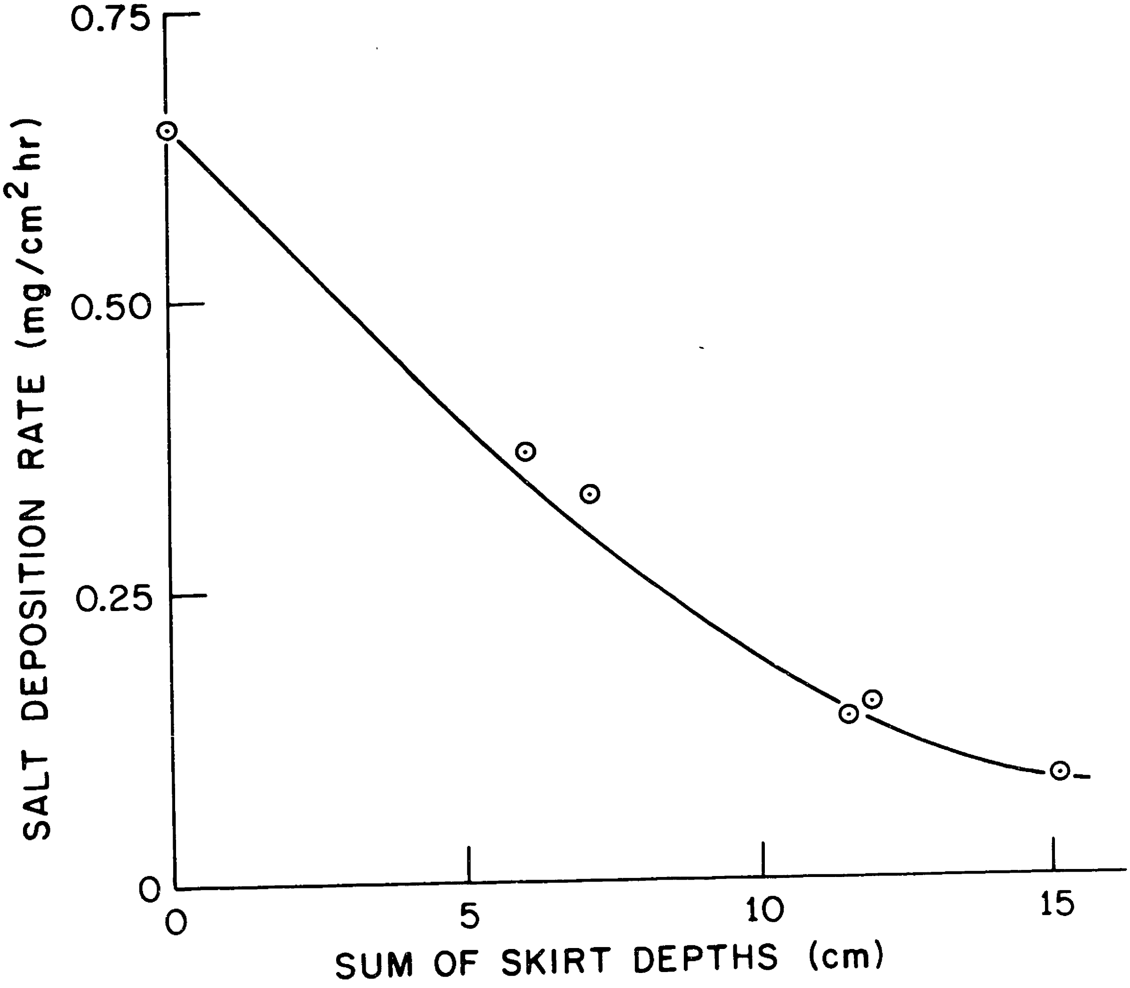


Fig. 5.3 Salt deposition rate on insulator undersurface as a function of the sum of skirt depths.

3) Dry band formation is eliminated, thereby eliminating discharging.

In order to look at some of these factors, several tests were carried out. The project was able to obtain two different suspension insulators with semiconducting glaze. Both were roughly the same shape and size as a standard unit. One, a foreign made unit provided by a Canadian utility, drew 3 mA in still 25°C air at 15 kV, while the other, of American manufacture, drew about 1 mA.

Both units were subjected to test conditions of 15 kV, 9% fog, and 8 mph wind. These conditions would flash over a standard unit in 10-15 minutes. However there was no increase of leakage current and no discharging. After these tests, the insulator surfaces were always perfectly dry. Thus under test conditions presumably more severe than nature, both insulators performed perfectly. This can be attributed to surface warmth keeping the surface dry.

Some tests were conducted in which the 3 mA unit was sprayed with bentonite, and then exposed to 9% fog until it was dripping wet. Voltage was then applied suddenly. It was found that flashover could be obtained as low as 10 kV. This is the same voltage at which an ordinary insulator would flash over. However at this voltage, due to power supply limitations, the voltage waveform becomes distorted, and an accurate comparison was not possible. In any event there did not appear to be much performance difference in this crude wet contaminant test.

Another test was done in which the 1 mA unit was coated with

Photoflo, cooled to 7.5°C, and then exposed to 9% fog and 8 mph wind at 15 kV. This time a definite wet film formed on the surface as indicated by a rapid rise of leakage current when fog was applied. No discharging was observed during 15 minutes, by which time a normal unit would have flashed over. At 15 minutes the voltage was raised 1 kV every 15 seconds until 25 kV was reached. No flashover or discharging occurred. The voltage was then removed. The insulator was examined and found to be wet over most of the surface. Fog and wind were then re-applied without voltage to get the entire surface wet. By raising the voltage rapidly (∼1kV/sec) flashover could be obtained at about 13.5 kV. However, starting with a wet insulator, if the voltage was raised slowly to 15 kV over about a minute, no flashover occurred. With the voltage held at 15 kV with the fog and wind still on the leakage current fell to a steady value in about 5 minutes. After 10 minutes the insulator was inspected. The surface was dry except for a few isolated drips on the bottom.

Judging from these preliminary tests, the primary factor in improving performance is the surface warmth. In light fogs the insulator will remain completely dry. In heavy spray situations, where part of the surface becomes wet, the extra stress across the dry zone will generate additional heat, causing unusually wide dry bands to form.

Apparently there is no way to measure the performance difference between a semiconducting unit and a normal one using an artificial test. In a realistic slow fog test the insulator never gets wet. In a wet contaminant test, the insulators are completely covered with a wet layer, something which apparently can not occur in practice on an energized line with semiconducting units, and is thus an unrealistic simulation of normal operating conditions.

The tests described here were exploratory in nature and are not to be considered as final. At present all that can be said is that for realistic test conditions, the semiconducting unit is far superior to the standard unit. The real issue seems to be, not their contamination performance, but other factors such as cost, life expectancy, and power drain. With respect to power drain, the 1 mA unit performed just as well as the 3 mA unit. Perhaps even smaller currents are possible, although below about 1 mA long strings might begin to exhibit non-linear voltage distribution due to capacitive effects.

5.4 Summary and Conclusions

This chapter considered the effect of modifying the standard suspension insulator in order to improve its contamination performance. Both shape modifications and semiconducting glazes were studied.

Salt fog tests were done on a variety of specially shaped insulators in order to determine how shape variations affect performance. It was found that the creepage path on the bottom was the factor most related to performance. However rain washing was not simulated, and exposed creepage types may actually be best in cases where the deposits are susceptible to rain washing.

The semiconducting glaze units performed almost ideally under realistic conditions. This could be attributed largely to surface warmth preventing moisture build-up. However these units do flash over in a wet contaminant test. Apparently the only hazardous operating condition would be the energizing of a line which had been dead during heavy dew or fog. The decisive factors in choosing a semiconducting insulator seem to be the life expectancy and the power drain. Under the relatively severe MIT fog conditions a unit dissipating 15 watts performed just as well as one dissipating 45 watts.

CHAPTER 6

SUMMARY, CONCLUSIONS, AND SUGGESTIONS FOR FUTURE RESEARCH

6.1 Summary and Conclusions

There are several distinct steps leading to the contamination flashover of an insulator. The first stage consists of the deposition of dry contaminant containing conducting salts, followed by the deposition of moisture. In some cases, as in salt storms, the water and dissolved salts may arrive together on the insulator surface. The combination of moisture and soluble salts produces a conducting film on the insulator surface. The current flow through this film causes evaporation at points of high resistivity, and dry bands form. Due to the concentration of voltage stress these dry bands break down, causing visible scintillations on the insulator. If the contamination is severe enough, these scintillations can bridge the insulator and trigger a power arc. This sequence of events necessary for flashover may be conveniently divided into the four distinct steps listed below:

1) deposition of conducting salts and moisture
2) dry band formation
3) electrical breakdown of dry band(s)
4) propagation of the discharge across the moist film, bridging the insulator

Each one of these events is a necessary stage in the development of full flashover. The flashover problem is thus vulnerable to attack at four separate points since if any of these four events can be arrested, contamination flashover will not occur. This study was conceived with the objective of finding ways to reduce or prevent if possible the occurrence of contamination flashover. With this goal in mind the four stages listed above were subjected to varying degrees of experimental and theoretical scrutiny.

Stage 1, the deposition of contaminant, was studied in several ways. First, a series of salt fog tests was done on suspension insulators of seven different shapes which were subjected to identical conditions of salt fog, voltage, and wind. It was found that insulators with undersurfaces shielded from the fog tended to perform best. The shielding effect was shown to be closely related to the sum of the skirt depths. However in these tests the effect of rain washing was not simulated, and exposed creepage types may be better in cases where rain washing is effective. The results are applicable to salt storm situations near the sea, or other cases where fog conductivity is an important ingredient of flashover.

Insulators removed from service are usually found to have a greater concentration of contaminant around the pin. One reason for this may be permeation through a porous surface layer from the wet region into the dry zone around the pin. To look at this effect, a number of salt fog tests were done on standard suspension insulators coated with a porous clay. It was found that the salt in the inner region of the insulator bottom tended to build up at a rate which increased with voltage. Several possibilities were suggested for this, including field enhanced permeation, but the exact reason could not be determined from the data.

Tests on insulators with semiconducting glazes in salt fog showed that moisture buildup never occurred on the surface, despite the fact that the fog conditions were more severe than in nature. A unit drawing 1 mA was just as effective in warding off fog as one drawing 3 mA. These insulators always performed perfectly under slow fog conditions when energized. However, if the fog was applied to a dead unit, a continuous moisture film would form. When voltage was applied suddenly, flashover occurred. Apparently then the success of this type depends on the drying action, which interrupts the flashover process at stage 1.

Stage 2, the formation of dry bands, appears impossible to prevent. A heavily contaminated insulator completely covered with a wet film would dissipate about 10 kilowatts. At this power level dry bands will form in short order no matter how the contaminant is distributed. It would appear that the prevention of dry banding is impossible, although by means of appropriate design dry bands might be encouraged to form in favorable locations. McElroy (1969) had already conducted extensive studies on dry band formation, and in view of this it was felt that an additional study was not needed at this time.

The concentration of voltage stress can lead to electrical breakdown of the dry gap, which constitutes stage 3 of flashover. During tests on standard suspension insulators coated with Photoflo it was found that breakdown could be triggered by the electric field pulling water filaments into the dry zone, shortening the sparking distance and triggering scintillations. This mechanism did not occur as readily on insulators with a porous clay coating since the capillary forces inhibited filament formation. As a consequence, clay coated insulators scintillated very rarely, and sometimes not at all, compared with surges every minute or so on Photoflo coated units. The voltage needed to cause breakdown of the dry zone on clay coated insulators varied with the dry zone location, being 18 kV for dry zones on the 1st skirt and 23 kV for dry zones on the larger 2nd skirt. The normal working voltage of such an insulator is less than 15 kV. This suggests that an insulator of appropriate geometry having a water absorbant coating might successfully interrupt the flashover process at stage 3. In addition, the reduction of scintillation frequency could have practical application to synthetic insulators where discharge activity leads to deterioration of the insulator.

Under normal service conditions the first 3 stages of flashover occur quite readily. Discharge activity is frequently observed on insulators during fog or other adverse weather conditions. However these scintillations, or pre-discharges, usually do not bridge the insulator. Only in rare instances does a discharge make it across the whole insulator to trigger flashover. The conditions governing the propagation of a discharge across a moist film are only beginning to be understood, suggesting that if the conditions were better understood, insulator design could be modified to hinder discharge propagation, interrupting flashover at stage 4. Accordingly a large portion of this thesis was devoted to studying discharge propagation across moist conducting films.

To simplify the mathematical analysis and to permit close control of the surface conditions, tests were done on a flat plate insulator of simple geometry. In these tests the flat plate was exposed to salt fog until the surface resistivity fell to the desired value. Voltage was then applied suddenly, resulting in immediate discharge activity. Sometimes a discharge would bridge the insulator leading to flashover, and other times the discharge activity would cease after about a second, resulting in a withstand.

Supposedly the significant variable in such a case is the surface resistivity. However McElroy (1969) reported that increasing the amount of clay made the plate more resistant to flashover. A number of tests done with various amounts of clay on the surface failed to show any effect of the clay, provided the high voltage resistivity determined from the discharge current record was used. However, if the resistivity was determined using a 50 volt bridge, heavier clay coatings were apparently more resistant to flashover, as McElroy found. This was attributed to poor contact between the water film and the electrodes for the lighter clay coatings. When high voltage is applied these regions of poor contact are bridged by discharging. At the higher clay levels, the clay acts as a blotter, sucking water up against the electrodes, and the high and low voltage resistivities were about equal. Thus high voltage resistivity measurements more accurately reflect the true surface resistivity.

The discharging on the flat plate was on the top whereas scintillations on actual insulators are normally on the bottom. To see what difference this makes, tests were done with the flat plate inverted. No difference could be detected. To see if thermal buoyant forces affect discharge propagation, tests were done with the plate in various orientations. It made little or no difference whether the discharge root was moving up, down, or sideways, indicating that thermal buoyant forces do not play a dominant role in discharge root motion.

For high clay levels, flashover tended to occur when the wet film was acting as a cathode, but there is not enough data to be sure that a polarity effect exists. Reignition angles of 75° and higher were observed. The asymmetry of the current waveform suggested that using a static volt-ampere discharge characteristic may not be a good approximation, and that reignition effects may have to be considered for accurate modeling.

Tests were done using coatings of two different clays, bentonite and kaolinite. The kaolinite was more resistant to flashover, but this was tentatively attributed to discharge activity at the outer electrode. This may have been due to poor contact between the film and the outer electrode caused by poor permeation properties of the kaolinite used.

The flat plate data was correlated with the extinction theory of Obenaus and found to be reasonably consistent. Several other theoretical approaches were rejected as having no physical basis. Unfortunately the theory of Obenaus says nothing about the physical processes giving rise to discharge root motion. Several previous suggestions were examined, including the possibility of thermal, electrostatic, or electromagnetic forces pulling the discharge across the surface. An order of magnitude calculation showed the electromagnetic forces to be negligible. Thermal and electrostatic forces were found to be on the same order of magnitude. However the vertical plate experiments seem to rule out thermal forces, since discharges moved up or down with equal ease. Very high discharge propagation velocities up to 600 meters/second observed by Hesketh (1967) seem to rule out electrostatic forces. Two new suggestions were made, electric breakdown and thermal ionization at the discharge root. However the data available is not yet adequate for evaluating these suggestions.

The wettability of the surface was found to have some bearing on insulator behavior. A clean weathered insulator showed a much more rapid rise of leakage current than a clean new insulator. However their minimum flashover voltages were about the same. The fastest rise of leakage current occurred on insulators coated with Photoflo or bentonite, both of which encourage continuous films to form. These coated insulators flashed over at less than half the voltage of the clean new or weathered units.

In order to relate the above work to operating experience, field contaminated insulators were exposed to a variety of conditions. Wind was found to suppress discharge activity. Condensation seemed to make no difference in performance, presumably because the fog is so dense that the extra deposition due to condensation doesn't matter.

Under natural conditions or in other test arrangements where the fog is less dense condensation may of course play a critical role in bringing about flashover. Using 1% salt fog instead of distilled water substantially lowered the flashover voltage, suggesting that conducting fog is a particularly severe operating condition. When testing two field contaminated insulators in series, voltage imbalance caused a 20% reduction in the flashover voltage. Strings rather than single units should be used to evaluate the insulation strength of naturally contaminated units.

6.2 Suggestions for Future Research

A theoretical question not yet resolved is the importance of reignition effects. Flat plate tests should be done using d.c. of both polarities. The results could then be compared with the data already obtained using a.c. This would not only indicate the importance of reignition and polarity effects, but it would help establish d.c. insulation levels relative to the a.c. levels already in use.

High speed photographic and oscillographic studies should be made of the flashover process. This might permit the physical flashover mechanism to be identified. A more accurate theoretical model could then be constructed enabling an evaluation of actual insulator designs. The model could also be used to predict flashover for a non-uniform distribution of contaminant. It might then be possible to modify insulator design to encourage favorable deposit distributions.

The effect of electrode material should be studied since metal vapor can change the discharge characteristics. The effect on the discharge of water vapor and other substances from the contaminant layer should also be investigated. Chemical reactions occurring during discharging may alter the contaminant layer, for example by the production of NO_2 which can react with water to form a highly conducting electrolyte. This could lead to flashover under field conditions where the contaminant originally present could not by itself cause flashover. The suppression of discharging by wind should be looked into.

The effect of thermal and electric forces on detached discharges needs study since Flugum (1971) has shown that such detached discharges are responsible for the poor performance of horizontal strings in wet contaminant tests. A better understanding of how these forces act could lead to an improvement in performance.

Thermal effects concerned with film heating and drying should be modeled more accurately. The transient heating at the discharge root may turn out to be quite important. The flashover delay in flat plate testing is apparently due to drying effects, but the amount of drying necessary before flashover can occur is not known.

The reason for the concentration of contaminant in the dry zone deserves further attention. Tests should be done using a simple geometry where the effect of electric forces could be modeled.

Further experiments should be done to determine the role of surface effects, particularly bead formation. A model for the rupture of the water droplets by the electric stress should be constructed and compared with experiment.

More extensive tests should be done on field contaminated insulators and the results correlated with operating experience. This is the only way to make sure that test procedures and theoretical approaches reflect actual operating conditions.

APPENDIX I

ELECTRICAL TEST EQUIPMENT AND CIRCUITS

The equipment used for this thesis was substantially the same as that used by McElroy (1969) and has been fully described by him. However, for convenience, the major electrical features of the test setup are reviewed briefly below.

The test voltage is provided by a 200 kVA, 550 volt/50 kV testing transformer. The incoming 2300 volt supply can be stepped down to either 60, 120, 240, or 480 volts by means of two 50 kVA multiple winding dry transformers. This feeds an induction regulator connected to the primary of the test transformer. The available short circuit current is limited mainly by the reactance of this induction regulator. The short circuit current was directly measured with 62 volts input to the induction regulator by running the motor driven induction regulator up from zero to full voltage under both open and short circuit conditions. The open circuit voltage and short circuit current were directly recorded on a chart recorder, resulting in the short circuit current characteristic of Fig. A1.1. This curve may be compared with the somewhat unusual characteristic obtained by McElroy (McElroy, 1969; McElroy, Lyon, Phelps, and Woodson, 1970). The hump in the center of the curve of Fig. A1.1 is probably due to the short circuited quadrature winding normally used to reduce mid-range induction regulator reactance. The short circuit was also measured directly by setting the output at a given voltage, and then shorting the secondary through an ammeter. These directly

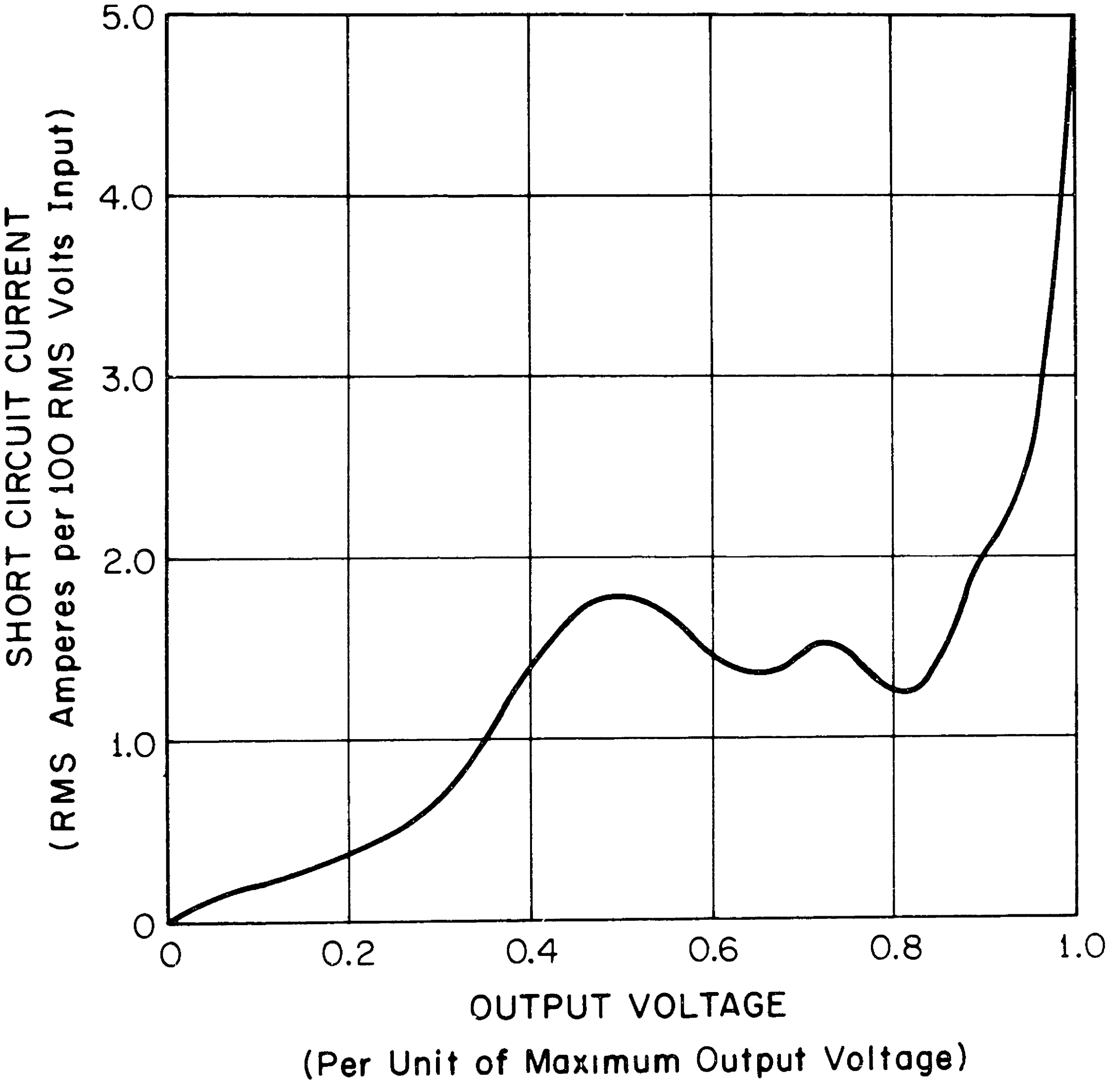


Fig. A1.1 Short circuit current capability of high voltage test set as a function of voltage setting. The curve is based on a direct measurement done at 62 volts r.m.s. input.

Table A1.1

Directly Measured Short Circuit Currents of Voltage Source

Output Voltage (kV)	I_{SC} (Amperes)	
	123 V input	247 V input
4	0.84	0.61
5	1.67	0.89
6	2.23	1.19
7	2.39	1.36
8	1.85	-
9	1.89	-
10	1.95	-

measured values are given in Table A1.1.

During actual tests the leakage and discharge currents were monitored using the circuit of Fig. A1.2. The leakage current was recorded with an Esterline-Angus recording milliameter having a chart speed of about 12" per hour. The sensitivity was set at 2.0 mA rms full scale for most tests. The discharge currents were recorded with a Honeywell 1508 A Visicorder which records on light sensitive paper using mirror galvonometers. The paper drive speed could be varied in steps from 0.15 inches/second to 120 inches/second. The type of galvonometer usually used has a frequency response of ±5% from 0 to 1000 Hz. The sensitivity could be varied but was normally about 500 mA peak for full scale deflection. Photos of typical Visicorder records can be found in McElroy's thesis (1969).

For high speed discharge current recording it was necessary to build an automatic paper drive control since manual control often resulted in a good deal of wasted paper. Maximum drive speed of 120 inches/second corresponds to $1.30 worth of paper per second. The remote control circuit is shown in Fig. A1.3 with the relays in standby configuration. When the current exceeds a certain threshold level the drive is actuated by the opening of relay K1. If the current then drops down again, the drive is turned off after a time delay adjustable up to about one second. If flashover occurs the drive is stopped at once by the opening of relay K2.

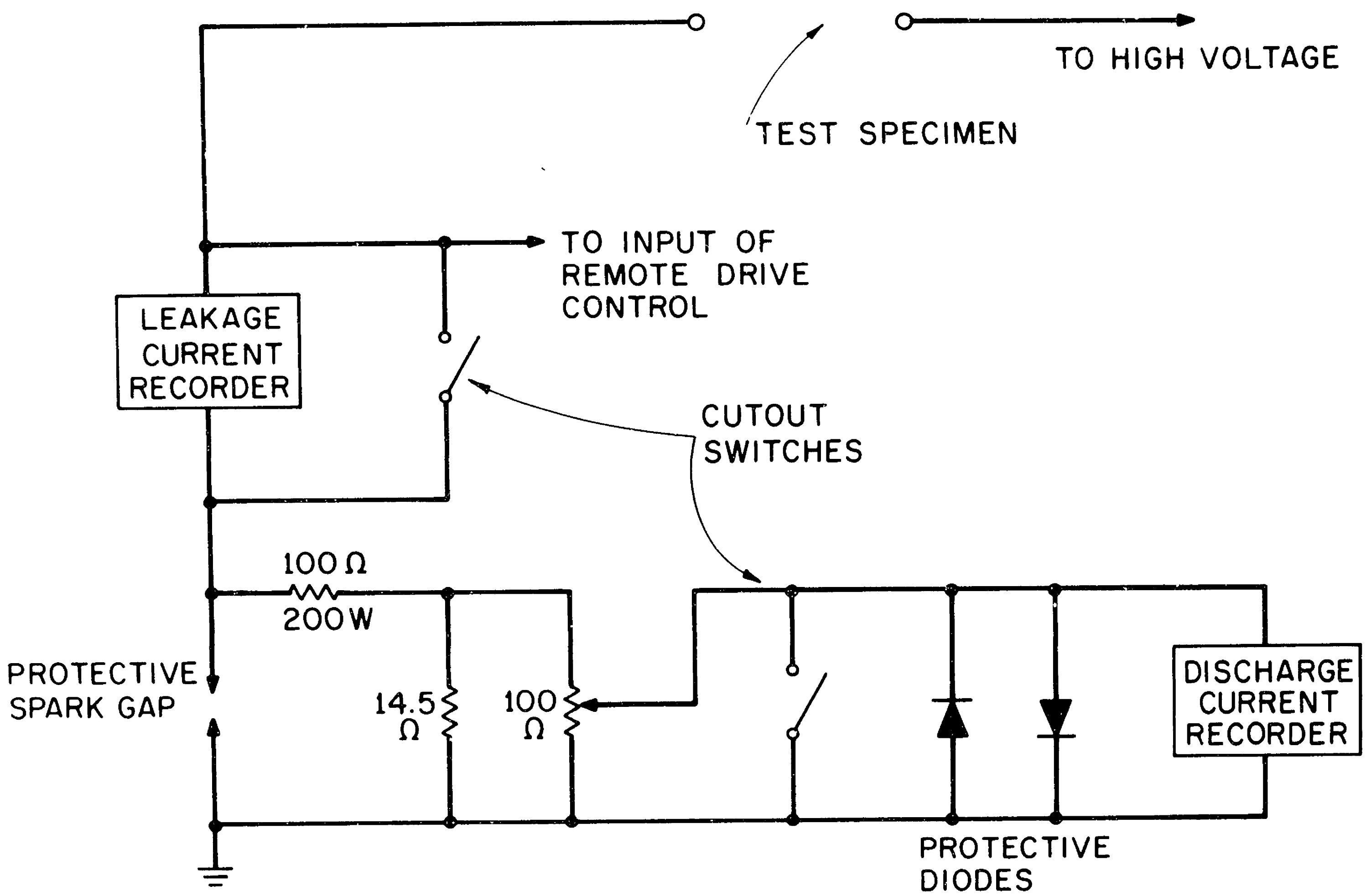


Fig. A1.2 Connection Diagram of Current Recording Instruments

Fig. A1.3 (Opposite) Visicorder remote drive control. This circuit controls the paper drive so that a record is made only when discharge activity is taking place. The parts list is given below.

C1, C2	1.0 μF 400 WVDC
D1, D2	1N4723
K1, K2	Potter and Brumfield RS5D SPDT relay, 2.5 mA sensitivity
R1	33K 1W
R2, R7	1M 2W
R3	500K 2W
R4, R8	2K 1W
R5, R9	25K 2W
R6	1.6M 1W
V1	6SN7GTB

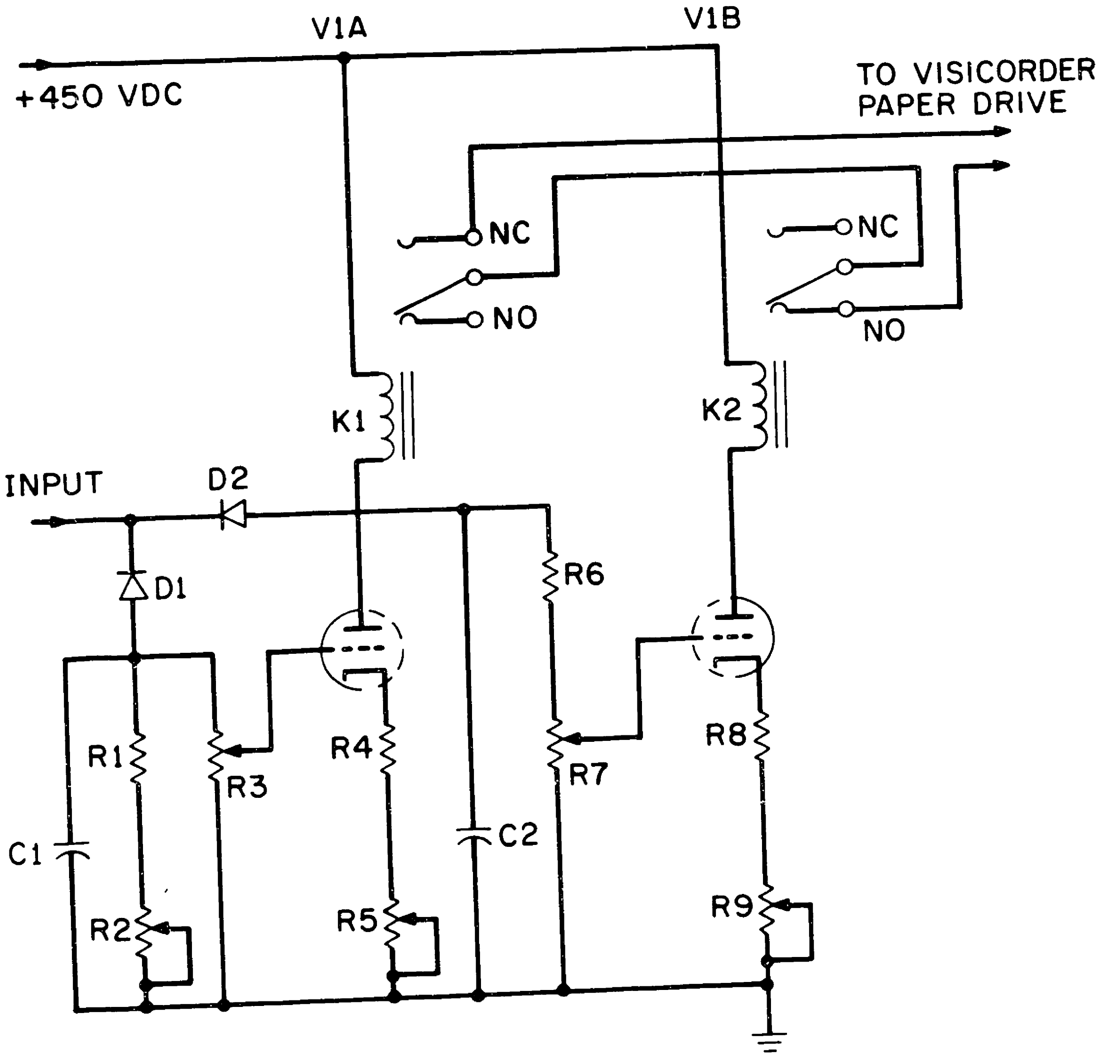


Fig. A1.3 (cont.) Visicorder Remote Drive Control

APPENDIX 2

SPEARMAN'S RANK CORRELATION COEFFICIENT

Often two sets of data cannot be compared on a strictly numerical basis. As an example, say that six insulator types are ranked in order of performance in a salt fog test. Suppose another ranking has been obtained on the basis of long term testing at an outdoor test station. Table A2.1 gives a hypothetical case for purposes of illustration. The question arises whether the salt fog test gives a ranking substantially the same as that obtained from the long term results. If so, then the more expensive long term testing could be bypassed, at least for preliminary design screening.

One might simply inspect the two rankings to see how well they correspond, but this is a matter of judgment and opinions can vary. Fortunately there is a statistical procedure to determine the closeness of correspondence between two rankings. A quantity known as Spearman's rank correlation coefficient can be computed from the formula*

$$r_s = 1 - \frac{6 \Sigma d^2}{n(n^2-1)} \qquad \text{(A2.1)}$$

where n is the number of pairs of data and Σd^2 is the sum of the squared differences in ranks. The coefficient is +1 for a perfect correspondence in ranking and -1 for perfect reverse correspondence. Table A2.1 shows a sample computation.

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*Bennett, C., and N. Franklin, "Statistical Analysis in Chemistry and the Chemical Industry," John Wiley and Sons, Inc., London, 1954, pp 283-286.

TABLE A2.1

EXAMPLE OF RANK CORRELATION COMPUTATION

Insulator Type	Insulator Rank in Clean Fog Test	Rank in Outdoor Test	d	d^2
A	2	2	0	0
B	6	6	0	0
C	1	1	0	0
D	3	5	-2	4
E	5	3	2	4
F	4	4	0	0
				$\Sigma d^2 = 8$

$$r_s = 1 - \frac{6\ \Sigma d^2}{n(n^2-1)} = 1 - \frac{(6)(8)}{(6)(35)} = +\ 0.77$$

Once r_s has been computed it is necessary to test for statistical significance. This test is necessary to see whether the apparent correlation could have resulted by chance from rankings that really had no connection. Tables have been computed to enable this to be done quickly.* For convenience of reference, Table A2.2 gives the critical values of r_s up to $n = 30$. For $n > 30$ Student's t test can give the critical values.** The quantity γ is the probability that the absolute value of Spearman's coefficient will exceed the given value by chance. Thus for a sample size of six, there is a 10% chance that r_s could exceed 0.83 for uncorrelated rankings. This 10% chance applies only when it is not known whether the correspondence between rankings should be direct or inverse. For example, in an experiment to determine the effect of hi-fi music on the yield of corn fields, tests could be done on five plots exposed to five different levels of loudness. Since it is not known beforehand how music level will affect corn yield, the values of γ given in Table A2.2 should be used. However, if it is expected that the rankings should correspond, then the values of γ given in Table A2.2 should be divided by two.

Thus for the insulator test results one would expect positive correlation between the two rankings. Therefore there is a 5% probability that the coefficient could exceed +0.83 by chance, and a 1% probability that it could exceed +0.94. Since in the example given,

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* "Handbook of Tables for Probability and Statistics," W.H. Beyer, Ed., The Chemical Rubber Co., Cleveland, 1966, pp. 330-331.

**Moroney, M.J., "Facts from Figures," Penguin Books, Baltimore, 1965, pp. 334-336.

TABLE A2.2

CRITICAL VALUES OF SPEARMAN'S RANK CORRELATION COEFFICIENT

n	$\gamma=0.10$	$\gamma=0.05$	$\gamma=0.02$	$\gamma=0.01$
5	0.90	-	-	-
6	.83	0.89	0.94	-
7	.71	.79	.89	-
8	.64	.74	.83	0.88
9	.60	.68	.78	.83
10	.56	.65	.74	.79
11	.52	.62	.74	.82
12	.50	.59	.70	.78
13	.48	.57	.67	.74
14	.46	.54	.65	.72
15	.44	.52	.62	.69
16	.42	.51	.60	.67
17	.41	.49	.58	.64
18	.40	.48	.56	.63
19	.39	.46	.55	.61
20	.38	.45	.53	.59
22	.36	.43	.51	.56
24	.34	.41	.48	.54
26	.33	.39	.46	.52
28	.32	.38	.45	.50
30	.30	.36	.43	.48

the correlation coefficient is only +0.77, the correlation is not even significant to the 5% level. This means that in this hypothetical case the salt fog test is not a good indication of performance under natural test conditions. Naturally Spearman's coefficient may be used to test for correlation between any ranked data, for example, between insulator performance ranking and creepage path ranking.

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