ABB Inc.

HARD TO FIND INFORMATION ABOUT DISTRIBUTION SYSTEMS

Reference Material

August 28, 2002

5th EDITION

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Legal Notice

Jim Burke is an Institute Fellow at ABB and a recognized expert on power distribution systems. He has authored over 70 technical papers in the field, including two prize papers, as well as the book *Power Distribution Systems, Fundamentals and Application.* This document is a cumulative effort developed by Jim Burke spanning over thirty years of teaching. ABB makes no warranty and assumes no liability with respect to the accuracy, suitability or usefulness of the information contained within.

I. Preface

There have been little tidbits of information I have accumulated over the years that have helped me understand and analyze distribution systems. I have pinned them to my wall, taped them to my computer, stuffed them in my wallet and alas, copied them for my students. Much of them are hard, if not impossible, to find in any reference book. A large percentage of them could also be classified as personal opinion so they should be used carefully. For whatever, I hope they are as useful to you as they have been to me.

II. System Characteristics and Protection

A. Introduction

The distribution system shown below illustrates many of the features of a distribution system making it unique. The voltage level of a distribution system can be anywhere from about 5 kV to as high as 35 kV with the most common voltages in the 15 kV class. Areas served by a given voltage are proportional to the voltage itself indicating that, for the same load density, a 35 kV system can serve considerably longer lines. Lines can be as short as a mile or two and as long as 20 or 30 miles. Typically, however, lines are generally 10 miles or less. Short circuit levels at the substation are dependent on voltage level and substation size. The average short circuit level at a distribution substation has been shown, by survey, to be about 10,000 amperes. Feeder load current levels can be as high as 600 amperes but rarely exceed about 400 amperes with many never exceeding a couple of hundred amperes. Underground laterals are generally designed for 200 amperes of loading but rarely approach even half that value. A typical lateral load current is probably 50 amperes or less even during cold load pickup conditions.

B. Fault Levels

There are two types of faults, low impedance and high impedance. A high impedance fault is considered to be a fault that has a high Z due to the contact of the conductor to the earth, i.e., Z_f is high. By this definition, a bolted fault at the end of a feeder is still classified as a low impedance fault. A summary of findings on faults and their effects is as follows:

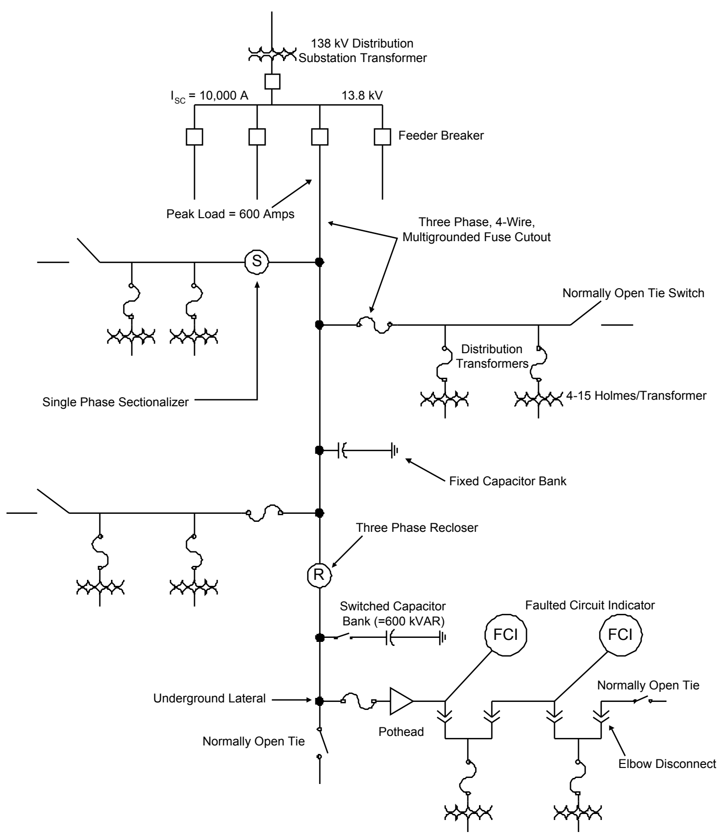


Figure 1. Typical distribution system

C. Low Impedance Faults

Low impedance faults or bolted faults can be either very high in current magnitude (10,000 amperes or above) or fairly low, e.g., 300 amperes at the end of a long feeder. Faults able to be detected by normal protective devices are all low impedance faults. These faults are such that the calculated value of fault current assuming a "bolted fault" and the actual are very similar. Most detectable faults, per study data, do indeed show that fault impedance is close to 0 ohms. This implies that the phase conductor either contacts the neutral wire or that the arc to the neutral conductor has a very low impedance. An EPRI study performed by the author over 10 years ago indicated that the maximum fault impedance for a detectable fault was 2 ohms or less. Figure 2, shown below, indicates that 2 ohms of fault impedance influences the level of fault current depending on location of the fault. As can be seen, 2 ohms of fault impedance considerably decreases the level of fault current for close in faults but has little effect for faults some distance away. What can be concluded is that ***fault impedance does not significantly affect faulted circuit indicator performance*** since low level faults are not greatly altered.

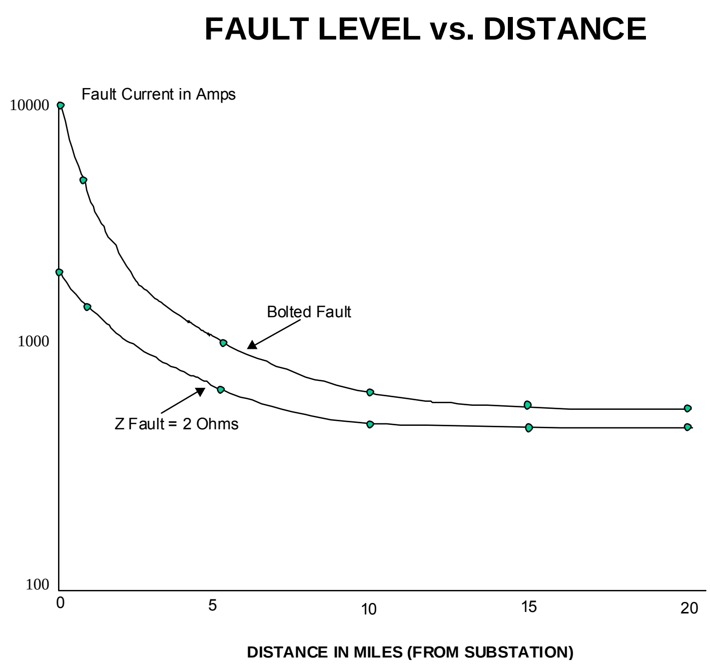


Figure 2. Low impedance faults

D. High Impedance Faults

High impedance faults are faults that are low in value, i.e., generally less than 100 amperes due to the impedance between the phase conductor and the surface on which the conductor falls. Figure 3, shown below, illustrates that most surface areas whether wet or dry do not conduct well. If one considers the fact that an 8 foot ground rod sunk into the earth more often than not results in an impedance of 100 ohms or greater, then it is not hard to visualize the fact that a conductor simply lying on a surface cannot be expected to have a low impedance. These faults, called high impedance faults, do not contact the neutral and do not arc to the neutral. They are not detectable by any conventional means and are not to be considered at all in the evaluation of FCIs and most other protective devices.

E. Surface Current Levels

Current Level in Amperes

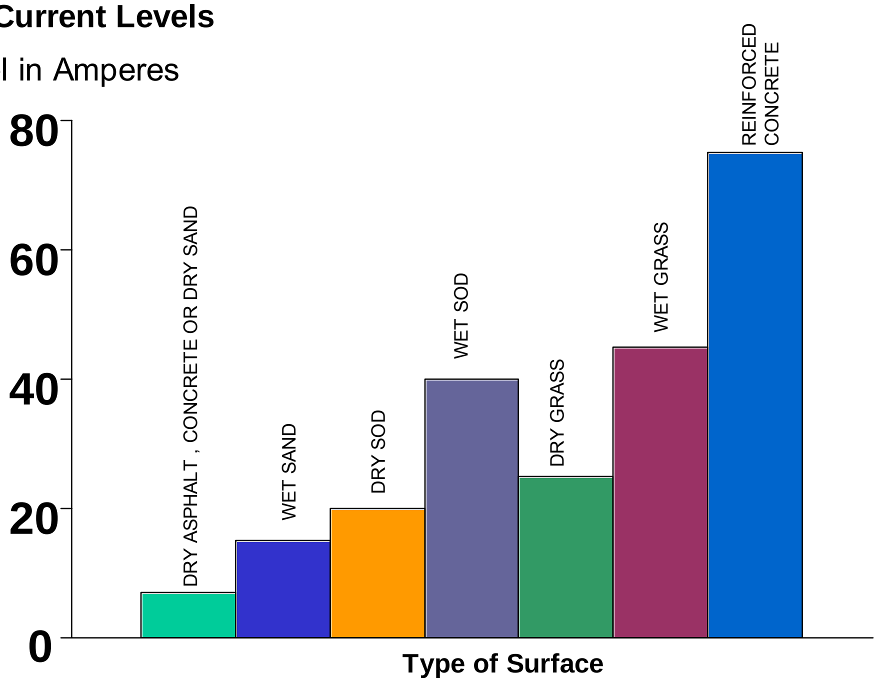
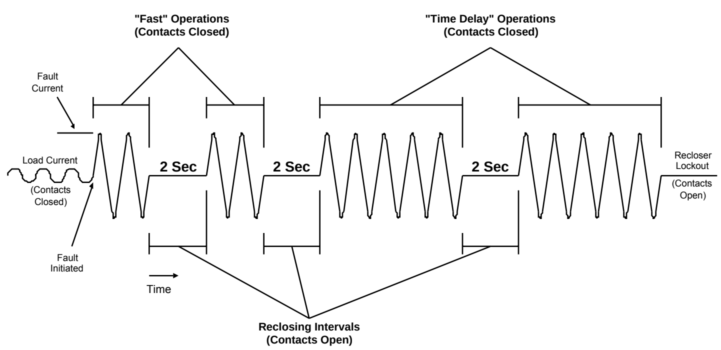


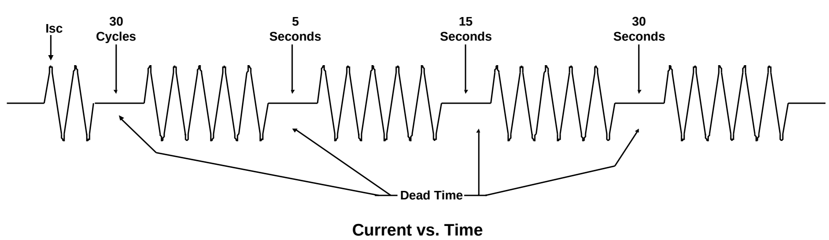
Figure 3. High impedance fault current levels

F. Reclosing and Inrush

On most systems where most faults are temporary, the concept of reclosing and the resulting inrush currents are a fact of life. Typical reclosing cycles for breakers and reclosers are different and are shown below in Figure 4.



Line Recloser



Feeder Breaker Reclosing

Figure 4. Reclosing sequences

These reclosing sequences produce inrush primarily resulting from the connected transformer kVA. This inrush current is high and can approach the actual fault current level in many instances. Figure 5 shows the relative magnitude of these currents. What keeps most protective devices from operating is that the duration of the inrush is generally short and as a consequence will not melt a fuse or operate a time delay relay.

G. Cold Load Pickup

Cold load pickup, occurring as the result of a permanent fault and long outage, is often maligned as the cause of many protective device misoperations. Figure 6, shown below, illustrates several cold load pickup curves developed by various sources. These curves are normally considered to be composed of the following three components:

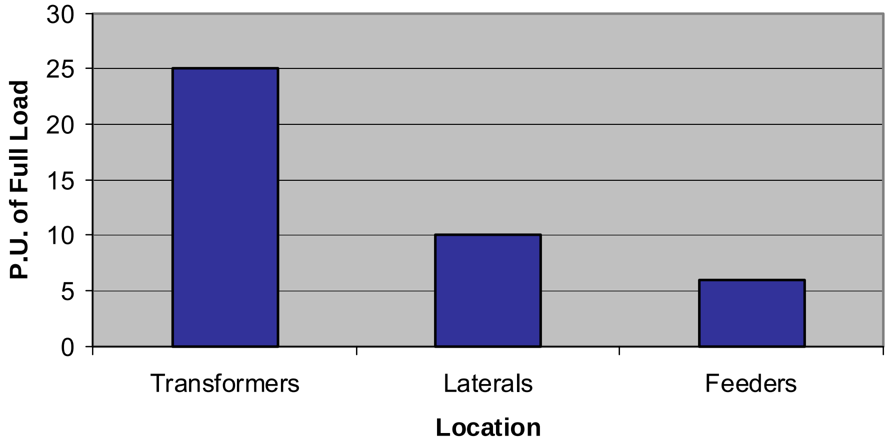


Figure 5. Magnitudes of inrush current

1) Inrush – lasting a few cycles
2) Motor starting – lasting a few seconds
3) Loss of diversity – lasting many minutes.

When a lateral fuse misoperates, it is probably not the result of this loss of diversity, i.e., the fuse is overloaded. This condition is rare on most laterals. Relay operation during cold load pickup is generally the result of a trip of the instantaneous unit and probably results from high inrush. Likewise, an FCI operation would not appear to be the result of loss of diversity but rather the high inrush currents. Since inrush occurs during all energization and not just as a result of cold load pickup, it can be concluded that cold load pickup is not a major factor in the application of FCIs.

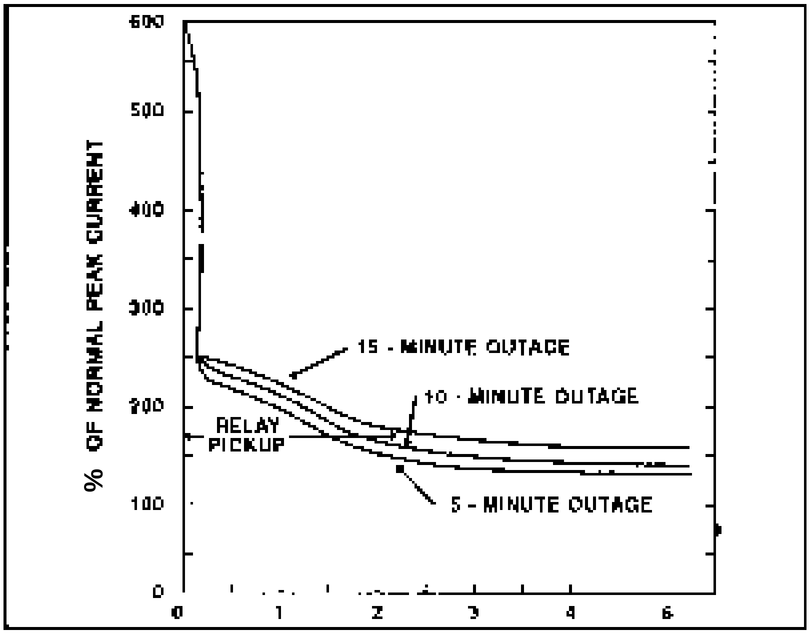


Figure 6. Cold-load inrush current characteristics for distribution circuits

H. Calculation of Fault Current

Line Faults Line-to-neutral fault =

$$\frac{E}{\sqrt{3} \bullet 2 \bullet Z_{\lambda}}$$

Where Z_{ℓ} is the line impedance and $2Z_{\ell}$ is the loop impedance assuming the impedance of the phase conductor and the neutral conductor are equal (some people use a 1.5 factor).

Line-to-Line Faults =

$$\frac{E}{2Z_{\lambda}}$$

Transformer Faults Line-to-neutral or three phase =

$$\frac{E}{\sqrt{3} \bullet Z_T}$$

Line-to-Line =

$$\frac{E}{2(Z_T + Z_{\lambda})} \quad \text{where} \quad Z_{\lambda} = \sqrt{R_L^2 + X_L^2}$$

$$Z_T = \frac{Z_{T\%} \bullet 10 \bullet E^2}{kVA}$$

I. Rules for Application of Fuses

1) Cold load pickup - after 15 minute outage, 200% for.5 seconds
140% for 5 seconds
after 4 hrs, all electric 300% for 5 minutes

2) "Damage" curve - 75% of minimum melt

3) Two expulsion fuses cannot be coordinated if the available fault current is great enough to indicate an interruption of less than .8 cycles.

4) “T” - SLOW and "K” - FAST

5) Current limiting fuses can be coordinated in the sub-cycle region.

6) Capacitor protection:

- The fuse should be rated for 165% of the normal capacitor current. The fuse should also clear within 300 seconds for the minimum short circuit current.
- If current exceeds the maximum case rupture point, a current limiting fuse must be used.
- Current limiting fuses should be used if a single parallel group exceeds 300 KVAR.

7) Transformer

- Inrush - 12 times for .1 sec.
- 25 times for .01 sec.
- Self protected - primary fuse rating is 10 to 14 times continuous when secondary breaker is used.
- Self protected - weak link is selected to be about 2 1/2 times the continuous when no secondary breaker is used (which means that minimum melt is in the area of 4 to 6 times rating).
- Conventional - primary fuse rated 2 to 3 times.
- General Purpose current limiting - 2 to 3 times continuous.
- Back-Up current limiting - the expulsion and CLF are usually coordinated such that the minimum melt I^2t of the expulsion fuse is equal to or less than that of the back up CLF.

8) Conductor burn down - not as great a problem today because loads are higher and hence conductors are larger.

9) General purpose - one which will successfully clear any current from its rated maximum interrupting current down to the current that will cause melting of the fusible element in one hour.

10) Back up - one which will successfully clear any current from its rated maximum interrupting down to the rated minimum interrupting current, which may be at the 10 second time period on the minimum melting time-current curve.

11) CLF - approximately 1/4 cycle operation; can limit energy by as much as 60 to 1.

12) Weak link - in oil is limited to between 1500 and 3500 amperes.

13) Weak link - in cutout is limited to 6000 to 15000 asymmetrical.

14) Lightning minimum fuse (12T-SLOW), (25K-FAST).

15) Energy stored in inductance = $\frac{1}{2}\ Li^2$

16) The maximum voltage produced by a C.L. fuse typically will not exceed 3.1 times the fuse rated maximum voltage.

17) The minimum sparkover allowed for a gapped arrester is 1.5 x 1.414 = 2.1 times arrester rating.

18) General practice is to keep the minimum sparkover of a gapped arrester at about 2.65 x arrester rating.

19) MOVs do not have a problem with CLF “kick voltages.”

J. Capacitor Fusing

1) **Purpose of fusing**:

a. to isolate faulted bank from system
b. to protect against bursting
c. to give indication
d. to allow manual switching (fuse control)
e. to isolate faulted capacitor from bank

2) **Recommended rating:**

a. The continuous-current capability of the fuse should be at least 165 percent of the normal capacitor-bank (for delta and floating wye banks the factor may be reduced to 150 percent if necessary).

b. The total clearing characteristics of the fuse link must be coordinated with the capacitor “case bursting” curves.

3) Tests have shown that expulsion fuse links will not satisfactorily protect against violent rupture where the fault current through the capacitor is greater than 5000 amperes.

4) The capacitor bank may be connected in a floating wye to limit short-circuit current to less than 5000 amperes.

5) **Inrush -** for a single bank, the inrush current is always less than the short-circuit value at the bank location.

6) **Inrush -** for parallel banks, the inrush current is always much greater than for a single bank.

7) **Expulsion fuses** offer the following advantages:

a. they are inexpensive and easily replaced.
b. offers a positive indication of operation.

8) **Current limiting fuses** are used where:

a. a high available short circuit exceeds the expulsion or non-vented fuse rating.
b. a current limiting fuse is needed to limit the high energy discharge from adjacent parallel capacitors effectively.
c. a non-venting fuse is needed in an enclosure.

9) The fuse link rating should be such that the link will melt in 300 seconds at 240 to 350 percent of normal load current.

10) The fuse link rating should be such that it melts in one second at not over 220 amperes and in .015 seconds at not over 1700 amperes.

11) The fuse rating must be chosen through the use of melting time-current characteristics curves, because fuse links of the same rating, but of different types and makes have a wide variation in the melting time at 300 seconds and at high currents.

12) **Safe zone –** usually greater damage than a slight swelling.

a. Zone 1 - suitable for locations where case rupture/or fluid leakage would present no hazard.
b. Zone 2 - suitable for locations which have been chosen after careful consideration of possible consequences associated with violent case ruptures.
c. Hazardous zone – unsafe for most applications. The case will often rupture with sufficient violence to damage adjacent units.

13) Manufacturers normally recommend that the group fuse size be limited by the 50% probability curve or the upper boundary of Zone 1.

14) Short circuit current in an open wye bank is limited to approximately 3 times normal current.

15) Current limiting fuses can be used for delta or grounded wye banks provided there is sufficient short circuit current to melt the fuse within ½ cycle.

K. Conductor Burndown

Conductor burndown is a function of (1) conductor size (2) whether the wire is bare or covered (3) the magnitude of the fault current (4) climatic conditions such as wind and (5) the duration of the fault current.

If burndown is less of a problem today than in years past it must be attributed to the trend of using heavier conductors and a lesser use of covered conductors. However, extensive outages and hazards to life and property still occur as the result of primary lines being burned down by flashover, tree branches failing on lines, etc. Insulated conductors, which are used less and less, anchor the arc at one point and thus are the most susceptible to being burned down. With bare conductors, except on multi-grounded neutral circuits, the motoring action of the current flux of an arc always tends to propel the arc along the line away from the power source until the arc elongates sufficiently to automatically extinguish itself. However, if the arc encounters some insulated object, the arc will stop traveling and may cause line burndown.

With tree branches falling on bare conductors, the arc may travel away and clear itself; however, the arc will generally re-establish itself at the original point and continue this procedure until the line burns down or the branch falls off the line. Limbs of soft spongy wood are more likely to burn clear than hard wood.

However one-half inch diameter branches of any wood, which cause a flashover, are apt to burn the lines down unless the fault is cleared quickly enough.

Figure 7 shows the burndown characteristics of several weatherproof conductors. Arc damage curves are given as arc is extended by traveling along the phase wire, it is extinguished but may be re-established across the original path. Generally, the neutral wire is burned down.

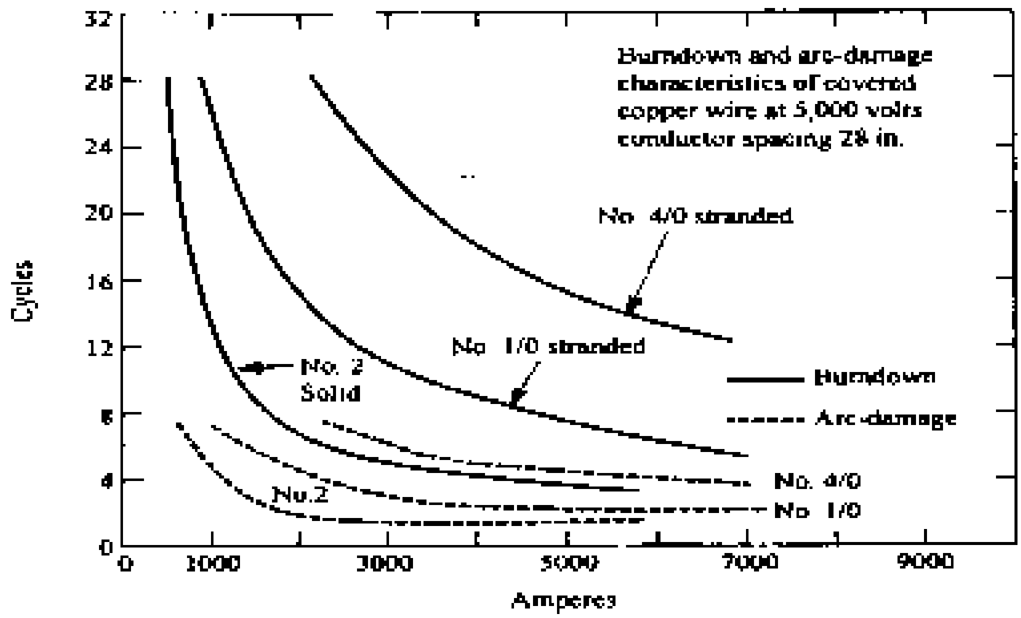


Figure 7. Burndown characteristics of several weatherproof conductors

L. Device Numbers

The devices in the switching equipment are referred to by numbers, with appropriate suffix letters (when necessary), according to the functions they perform. These numbers are based on a system which has been adopted as standard for automatic switchgear by the American Standards Association.

Table 1

Device No.	Function and Definition
11	CONTROL POWER TRANSFORMER is a transformer which serves as the source of a-c control power for operating a-c devices.
24	BUS-TIE CIRCUIT BREAKER serves to connect buses or bus sections together.
27	A-C UNDERVOLTAGE RELAY is one which functions on a given value of single-phase a-c under voltage.
43	TRANSFER DEVICE is a manually operated device which transfers the control circuit to modify the plan of operation of the switching equipment or of some of the devices.
50	SHORT-CIRCUIT SELECTIVE RELAY is one which function instantaneously on an excessive value of current.
51	A-C OVERCURRENT RELAY (inverse time) is one which functions when the current in an a-c circuit exceeds a given value.
52	A-C CIRCUIT BREAKER is one whose principal function is usually to interrupt short-circuit or fault currents.
64	GROUND PROTECTIVE RELAY is one which functions on failure of the insulation of a machine, transformer or other apparatus to ground. This function is, however, not applied to devices 51N and 67N connected in the residual or secondary neutral circuit of current transformers.
67	A-C POWER DIRECTIONAL OR A-C POWER DIRECTIONAL OVERCURRENT RELAY is one which functions on a desired value of power flow in a given direction or on a desired value of overcurrent with a-c power flow in a given direction.
78	PHASE-ANGLE MEASURING RELAY is one which functions at a predetermined phase angle between voltage and current.
87	DIFFERENTIAL CURRENT RELAY is a fault-detecting relay which functions on a differential current of a given percentage or amount.

M. Protection Abbreviations

CS -Control Switch
X - Auxiliary Relay
Y - Auxiliary Relay
YY - Auxiliary Relay
Z - Auxiliary Relay

1) To denote the location of the main device in the circuit or the type of circuit in which the device is used or with which it is associated, or otherwise identify its application in the circuit or equipment, the following are used:

N – Neutral
SI - Seal-in

2) To denote parts of the main device (except auxiliary contacts as covered under below), the following are used:

H - High set unit of relay
L - Low set unit of relay
OC - Operating coil
RC - Restraining coil
TC - Trip coil

3) To denote parts of the main device such as auxiliary contacts (except limit-switch contacts covered under 3 above) which move as part of the main device and are not actuated by external means. These auxiliary switches are designated as follows:

“a" - closed when main device is in energized or operated position
"b” - closed when main device is in de-energized or non-operated position.

4) To indicate special features, characteristics, the conditions when the contacts operate, or are made operative or placed in the circuit, the following are used:

A-	Automatic
ER-	Electrically Reset
HR-	Hand Rest
M-	Manual
TDC-	Time-delay Closing
TDDO-	Time-delay Dropping Out
TDO-	Time-delay Opening

To prevent any possible conflict, one letter or combination of letters has only one meaning on an individual equipment. Any other words beginning with the same letter are written out in full each time, or some other distinctive abbreviation is used.

N. Simple Coordination Rules

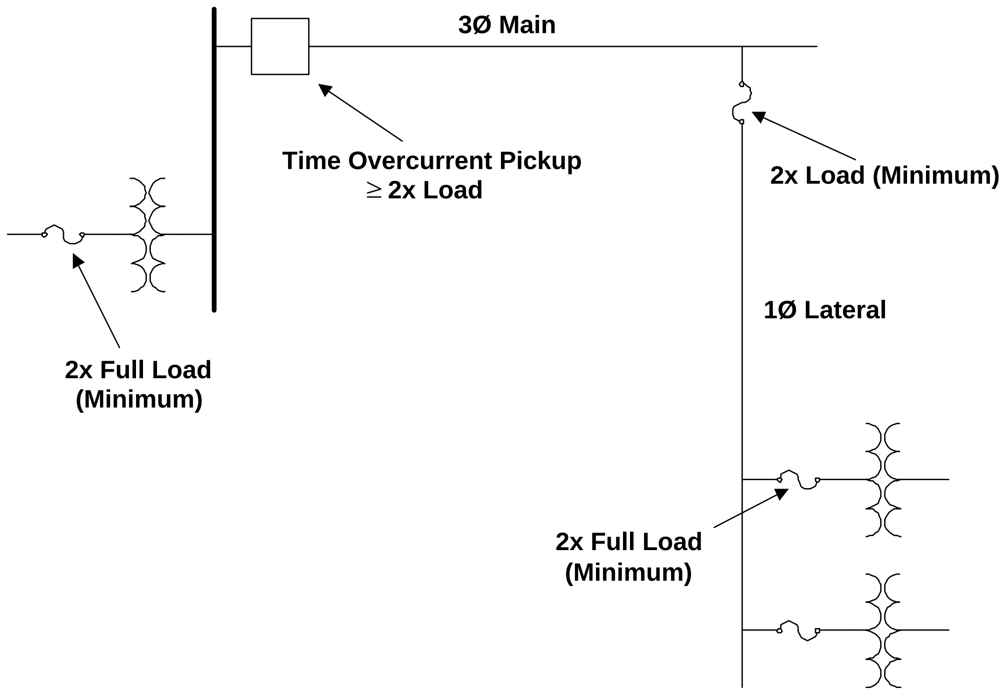


Figure 8. "Burke 2X rule"

There are few things more confusing in distribution engineering than trying to find out rules of overcurrent coordination, i.e., what size fuse to pick or where to set a relay, etc. The patented (*just kidding)* Burke 2X Rule states that when in doubt pick a device of twice the rating of what it is you're trying to protect as shown in Figure 8. This rule picks the minimum value you should normally consider and is generally as good as any of the much more complicated approaches you might see. For various reasons, you might want to go higher than this, which is usually OK. To go lower, you will generally get into trouble. Once exception to this rule is the fusing of capacitors where minimum size fusing is important to prevent case rupture.

O. Lightning Characteristics

1) Stroke currents

a. Maximum - 220,000 amperes
b. Minimum - 200 amperes
c. Average-10,000 to 15,000 amperes

2) Rise times – 1 to 100 microseconds

3) Lightning polarity - approximately 95% are negative

4) Annual variability (Empire State Building)

a.	Maximum number of hits	50
b.	Average	21
c.	Minimum	3

(8-year measurement period)

5) Direct strokes to T line - 1 per mile per year with keraunic levels between 30 and 65.

6) Lightning discharge currents in distribution arresters on primary distribution lines (composite of urban and rural)

Max. measured to date –	approx.	40,000 amps
I% of records at least		22,000 amps
5% of records at least		10,500 amps
10% of records at least		6,000 amps
50% of records at least		1,500 amps

7) Percent of distribution arresters receiving lightning currents at least as high as in Col. 4.

Table 2

Col. 1 Urban Circuits	Col. 2 Semi-urban Circuits	Col. 3 Rural Circuits	Col. 4 Discharge Circuits
20%	35%	45%	1,000 amps
1.6%	7%	12%	5,000 amps
.55%	3.5%	6%	10,000 amps
.12%	.9%	2.4%	20,000 amps
		.4%	40,000 amps

8) Number of distribution arrester operations per year (excluding repeated operations on multiple strokes).

Average on different systems - range	.5 to 1.1 per year
Max. recorded	6 per year
Max. number of successive operations of one arrester during one multiple lightning stroke -	12 operations.

P. Arc Impedence

While arcs are quite variable, a commonly accepted value for currents between 70 and 20,000 amperes has been an arc drop of 440V per foot, essentially independent of current magnitude.

$Z_{arc} = \quad 440\ l\ /\ I \qquad l$ = length of arc (in feet) $\quad I$ = current

Assume:

$I_F = 500$ amperes = I

Arc length = 2 ft.

$Z_{arc} = \quad 440 \bullet 2/5000 \quad = .176$ ohms $\quad \therefore$ Arc impedance is pretty small.

III. Transformers

A. Saturation Curve

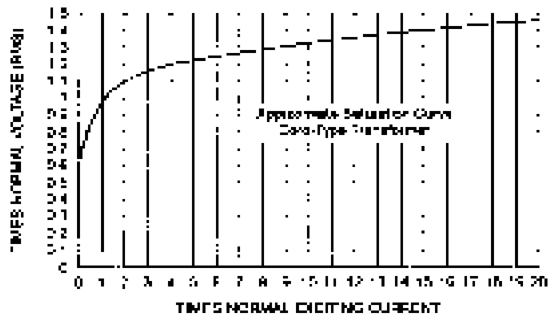


Figure 9

B. Insulation Levels

The following table gives the American standard test levels for insulation of distribution transformers.

Table 3

		Windings			Bushings		
		Impulse Tests (1.2 x 50 Wave)			Bushing Withstand Voltages		
		Chopped Wave					
Insulation Class and Nominal Bushing Rating	Low-frequency Dielectric Tests	Minimum Time to Flashover		Full Wave	60-cycle One-minute Dry	60-cycle 10-second Wet	Impulse 1.2 x 50 Wave
kV	kV	kV	Microseconds	kV	kV (Rms)	kV (Rms)	kV (Crest)
1.2	10	36	1.0	10	10	6	30
5.0	19	69	1.5	60	21	20	60
8.66	26	88	1.6	75	27	24	75
15.0	34	110	1.8	95	35	30	95
25.0	40	145	1.9	125	70	60	150
34.5	70	175	3.0	150	95	95	200
46.0	95	290	3.0	250	120	120	250
69.0	140	400	3.0	350	175	175	350

C. Δ-Y Transformer Banks

The following is a review of fault current magnitudes for various secondary faults on a Δ-Y transformer bank connection:

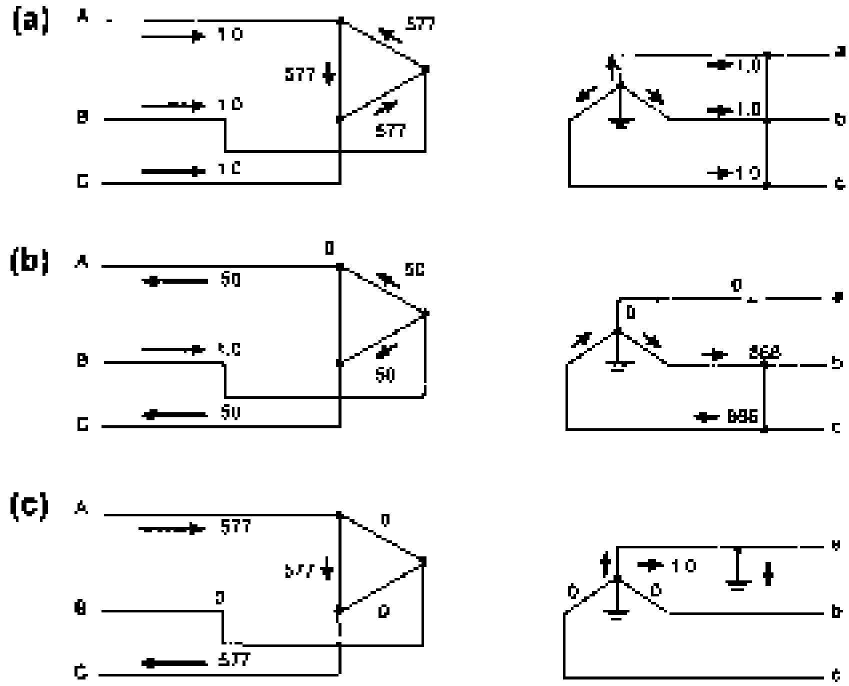


Figure 10. Δ-Y transformer banks

D. Transformer Loading

When the transformer is overloaded, the high temperature decreases the mechanical strength and increases the brittleness of the fibrous insulation. Even though the insulation strength of the unit may not be seriously decreased, transformer failure rate increases due to this mechanical brittleness.

- Insulation life of the transformer is where it loses 50% of its tensile strength. A transformer may continue beyond its predicted life if it is not disturbed by short circuit forces, etc.
- The temperature of top oil should never exceed 100 degrees C for power transformers with a 55 degree average winding rise insulation system. Oil overflow or excessive pressure could result.
- The temperature of top oil should not exceed 110C for those with a 65C average winding rise.
- Hot spot should not exceed 150C for 55C systems and 180C for 65C systems. Exceeding these temperature could result in free bubbles that could weaken dielectric strength.
- Peak short duration loading should never exceed 200%.
- Standards recommend that the transformer should be operated for normal life expectancy. In the event of an emergency, a 2.5% loss of life per day for a transformer may be acceptable.

- Percent Daily Load for Normal Life Expectancy with 30°C Cooling Air

Table 4

Duration of Peak load	Self-cooled with % load before peak of:		
Hours	50%	70%	90%
0.5	189	178	164
1	158	149	139
2	137	132	124
4	119	117	113
8	108	107	106

IV. Instrument Transformers

A. Two Types

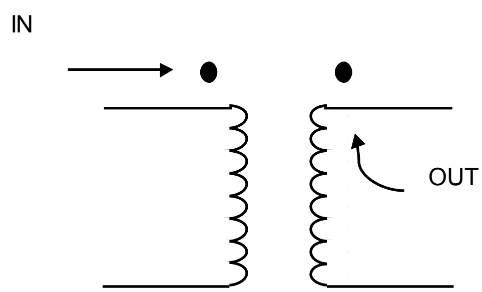
1) Potential (Usually 120v secondary)
2) Current (5 amps secondary at rated primary current)

B. Accuracy

3 factors will influence accuracy:

1) Design and construction of transducer
2) Circuit conditions (V, I and f)
3) Burden (in general, the higher the burden, the greater the error)

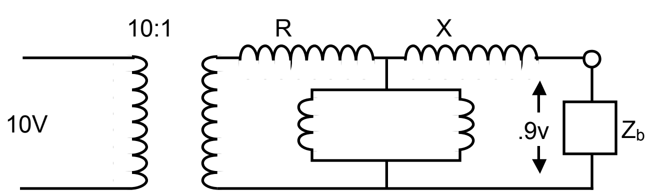
C. Potential Transformers



$$\text{RCF}= \frac{\text{True Ratio}}{\text{Marked Ratio}} \qquad \text{(RCF generally >1)}$$

Burden is measured in VA $\therefore$ $VA = \dfrac{E^2}{Z_b}$

Assume:



$$\text{True Ratio} = \frac{10}{.9} = 11.1$$

$$\Rightarrow \text{RCF} = \frac{11.1}{10} = 1.11$$

$$\text{Marked Ratio} = \frac{10}{1} = 10$$

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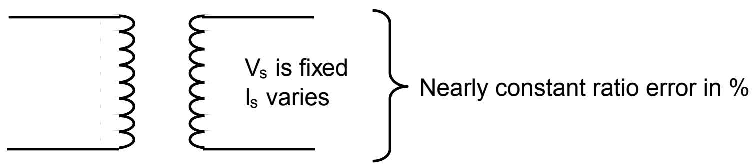
Voltage at secondary is low and must be compensated by 11% to get the actual primary voltage using the marked ratio.

D. Current Transformer

True Ratio = Marked Ratio X RCF

$$\therefore RCF = \frac{\text{True Ratio}}{\text{Marked Ratio}}$$

E. H-Class



Burdens are in series

e.g. 10H200 ⇒ 10% error @ 200V

∴ 20 (5 amp sec) = 100 amps ⇒ Z_b = 200/100 = 2Ω

⇒ 5 amps to 100 amps has ≤ 10% error if Z_b = 4Ω

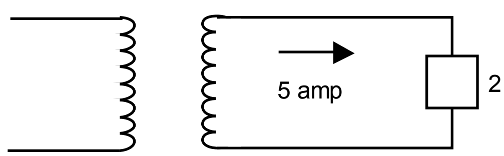
OR

If Z_b = 4Ω

200V/4Ω = 50 amp (10 times normal)

H-class – constant magnitude error (variable %)
L-class – constant % error (variable magnitude)

<u>Example:</u>
True Ratio = Marked Ratio X RCF
Assume Marked is 600/5 or 120:1 at rated amps and 2 ohms



1.002 and 1.003 are from manuf. chart

@ 100% amps True = 120 X 1.002 X 5 secondary
primary = 600 X 1.002 = 601.2
@ 20% amps True = 600 X .2 X 1.003 = 120.36 (Marked was 120)

F. Current Transformer Facts

1) Bushing CTs tend to be accurate more on high currents (due to large core and less saturation) than other types.

2) At low currents, BCT's are less accurate due to their larger exciting currents.

3) Rarely, if ever, is it necessary to determine the phase-angle error.

4) Accuracy calculations need to be made <u>only</u> for three-phase and single-phase to ground faults.

5) CT burden decreases as secondary current increases, because of saturation in the magnetic circuits of relays and other devices. At high saturation, the impedance approaches the dc resistance.

6) It is usually sufficiently accurate to add series burden impedance arithmetically.

7) The reactance of a tapped coil varies as the square of the coil turns, and the resistance varies approximately as the turns.

8) Impedance varies as the square of the pickup current.

9) Burden impedance are always connected in wye.

10) "Ratio correction factor" is defined as that factor by which the marked ratio of a current transformer must be multiplied to obtain the true ratio. These curves are considered standard application data.

11) The secondary-excitation-curve method of accuracy determination does not lend itself to general use except for bushing-type, or other, CT's with completely distributed secondary leakage, for which the secondary leakage reactance is so small that it may be assumed to be zero.

12) The curve of rms terminal voltage versus rms secondary current is approximately the secondary-excitation curve for the test frequency.

13) ASA Accuracy Classification:

a. Method assumes CT is supplying 20 times its rated secondary current to its burden.

b. The CT is classified on the basis of the maximum rms value of voltage that it can maintain at its secondary terminals without its ratio error exceeding a specified amount.

c. "H" stands for high internal secondary impedance.

d. "L" stands for low internal secondary impedance (bushing type).

e. 10H800 means the ratio error is l0% at 20 times rated voltage with a maximum secondary voltage of 800 and high internal secondary impedance.

f. Burden (max) - maximum specified voltage/20 x rated sec.

g. The higher the number after the letter, the better the CT.

h. A given l200/5 busing CT with 240 secondary turns is classified as l0L400: if a 120-turn completely distributed tap is used, then the applicable classification is 10L200.

i. For the same voltage and error classifications, the H transformer is better than the L for currents up to 20 times rated.

G. Glossary of Transducer Terms

Voltage Transformers - are used whenever the line voltage exceeds 480 volts or whatever lower voltage may be established by the user as a safe voltage limit. They are usually rated on a basis of 120 volts secondary voltage and used to reduce primary voltage to usable levels for transformer-rated meters.

Current Transformer - usually rated on a basis of 5 amperes secondary current and used to reduce primary current to usable levels for transformer-rated meters and to insulate and isolate meters from high voltage circuits.

Current Transformer Ratio - ratio of primary to secondary current. For current transformer rated 200:5, ratio is 200:5 or 40: 1.

Voltage Transformer Ratio - ratio of primary to secondary voltage. For voltage transformer rated 480:120, ratio is 4:1, 7200:120 or 60:1.

Transformer Ratio (TR) - total ratio of current and voltage transformers. For 200:5 C.T. and 480:120 P.T., TR = 40 x 4 = 160.

Weatherability - transformers are rated as indoor or outdoor, depending on construction (including hardware).

Accuracy Classification - accuracy of an instrument transformer at specified burdens. The number used to indicate accuracy is the maximum allowable error of the transformer for specified burdens. For example, 0.3 accuracy class means the maximum error will not exceed 0.3% at stated burdens.

Rated Burden - the load which may be imposed on the transformer secondaries by associated meter coils, leads and other connected devices without causing an error greater than the stated accuracy classification.

Current Transformer Burdens - normally expressed in ohms impedance such as B0.1,B-0.2,B-0.5,B-0.9,or B-1.8.Corresponding volt-ampere values are 2.5, 5.0, 12.5, 22.5, and 45.

Voltage Transformer Burdens - normally expressed as volt-amperes at a designated power factor. May be W, **X,** M, Y, or Z where W is 12.5 V.A. @ 0. 1Opf; X is 25 V.A. @ 0.70pf, M is 35 V.A. @ 0.20 pf, Y is 75 V.A. @ 0.85pf and Z is 200 V.A. @0.85 pf. The complete expression for a current transformer accuracy classification might be 0.3 at BO. 1, B-0.2, and B-0. 5, while the potential transformer might be 0.3 at W, X, M, and Y.

Continuous Thermal Rating Factor (TRF) - normally designated for current transformers and is the factor by which the rated primary current is multiplied to obtain the maximum allowable primary current without exceeding temperature rise standards and accuracy requirements. Example - if a 400:5 CT has a TRF of 4.0, the CT will continuously accept 400 x 4 or 1600 primary amperes with 5 x 4 or 20 amperes from the secondary. The thermal burden rating of a voltage transformer shall be specified in terms of the maximum burden in volt-amperes that the transformer can carry at rated secondary voltage without exceeding a given temperature rise.

Rated Insulation Class - denotes the nominal (line-to-line) voltage of the circuit on which it should be used. Associated Engineering Company has transformers rated for 600 volts through 138 kV.

Polarity - the relative polarity of the primary and secondary windings of a current transformer is indicated by polarity marks (usually white circles), associated with one end of each winding. When current enters at the polarity end of the primary winding, a current in phase with it leaves the polarity end of the secondary winding. Representation of primary marks on wiring diagrams are shown as black squares.

Hazardous Open-Circulating - operation of CTs with the secondary winding open can result in a high voltage across the secondary terminals which may be dangerous to personnel or equipment. Therefore, the secondary terminals should always be short circuited before a meter is removed from service. This may be done automatically with a by-pass in the socket or by a test switch for A-base meters.

V. Rules of Thumb for Uniformly Distributed Loads

It is very helpful to be able to perform a quick sanity check of system conditions "usually in your head" to develop a "feel" for whether there might be a problem. Three very helpful rules assuming a uniformly distributed load are as follows:

1) Capacitor placement - "2/3 rule"

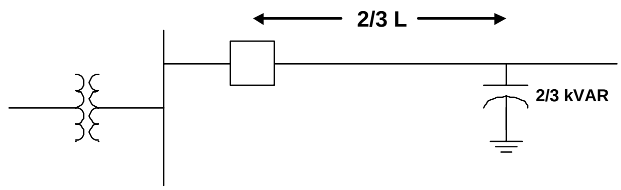


Figure 11. Optimum capacitor placement

"Optimum placement of capacitors at 2/3 the distance of the line, sizing the bank to meet 2/3 of the feeder VAR needs."

2) Losses - "1/3 rule"

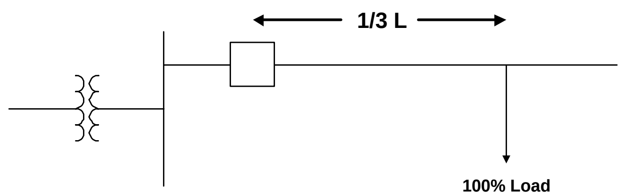


Figure 12. Equivalent losses

"Place all the load at 1/3 the distance to obtain the same losses as an evenly distributed load."

3) Voltage drop - "1/2 rule"

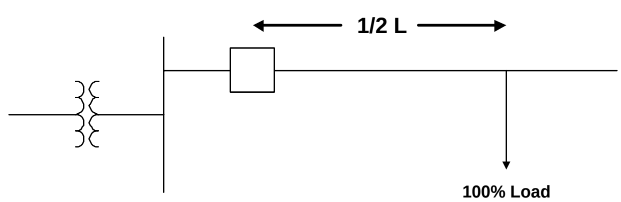


Figure 13. Equivalent voltage drop

"Place 100% of load at 1/2 point on the feeder to obtain the same voltage drop as the voltage at the end of the feeder for a uniform distribution load."

VI. Conductors and Cables

A. Conductor Current Rating

Table 5

Wire Size	Amps
6	55
4	75
2	105
1/0	145
2/0	170
3/0	200
4/0	240
336	330
397	370
565	480
795	620

B. Facts on Distribution Cable

1) Cable replacement occurs usually after 2 or 3 failures.

2) TRXLPE and EPR use is increasing.

3) Conduit is on the rise but most cable is direct buried.

4) About 60% of all cable is still going in direct buried.

5) Most common method to find fault is radar with a thumper, followed by a thumper by itself then an FCI.

6) Most utilities use an insulating jacket type, followed by the use of the semi-conducting jacket.

7) 30% use fiber optics in the underground system for telephone, SCADA, computer-to-computer, video, etc.

8) Jacketed EPR has <u>good</u> record.

9) HMWPE and non-jacketed XLPE have bad records.

C. Impedance of Cable

Impedance of the main feeder is:

1) .122 + j .175 ohms/mile (12kV, 1000 KCM)

2) .119 + j .190 ohms/mile (35kV, 1000 KCM)

Impedance of the lateral feed is:

1) .502 + j .211 ohm/mile (12kV, 4/0, 3∅)

2) .500 + j .238 ohm/mile (34kV, 4/0, 3∅)

3) 1.445 + j .552 ohms/mile (12kV, #4, 1∅)

4) 1.607 + j .595 ohms/mile (34kV, #4, 1∅)

Table 6

Impedance Table (R and X) For Commonly Used Wire and Cable

Wire Size	Type	Spacing	Resistance per 1000 Ft.	Reactance per 1000 Ft.
336 ACSR	Open Wire	3 Ft	0.068	0.128
#4	Open Wire	1.5 Ft	0.262	0.125
#2	Open Wire	1.5 Ft	0.163	0.120
#1/0	Open Wire	1.5 Ft.	0.105	0.113
#2/0	Open Wire	1.5 Ft	0.083	0.110
#4/0	Open Wire	1.5 Ft	0.053	0.106
#6	Open Wire	3.0 Ft.	0.413	0.146
#4	Open Wire	3.0 Ft	0.262	0.141
#2	Open Wire	3.0 Ft	0.181	0.143
#1/0	Open Wire	3.0 Ft.	0.105	0.125
#2/0	Open Wire	3.0 Ft	0.081	0.136
#4/0	Open Wire	3.0 Ft.	0.055	0.121
#2	Self Supp	Cable	0.162	0.052
#2/0	Self Supp.	Cable	0.084	0.046
#4/0	Self Supp.	Cable	0.053	0.041
#1/0	P&L	Cable	0.059	0.036
350 MCM	P&L	Cable	0.036	0.032
#1/0	Spacer	3.5 In	0.168	0.075
#4/0	Spacer	3.5 In.	0.084	0.067
#1/0	Spacer	5.0 In	0.168	0.086
#4/0	Spacer	5.0 In	0.084	0.079
1/0 Alum	Open Wire	3.0 Ft.	0.168	0.129
4/0 Alum	Open Wire	3.0 Ft.	0.092	0.129
397 Alum	Open Wire	3.0 Ft.	0.046	0.113
*1/0 Alum	Open Wire	1.5 Ft.	0.158	0.112
*4/0 Alum	Open Wire	1.5 Ft	0.084	0.106
*397 Alum ACSR	Open Wire	1.5 Ft	0.045	0.095
397 Alum	Open Wire	1.0 Ft	0.044	0.087
3-1/c 500 MCM	Network		0.024	0.032

*Armless Construction

VII. DSG – General Requirements

1) **Voltage -** Customer shall not cause voltage excursions. Any voltage excursions must be disconnected within 1 second.

2) **Flicker -** 2% at the dedicated transformer.

3) **Frequency - <** 5% Hz and removed in ≤ .2 seconds

4) **Harmonics - <** 5% - sum of squares

5) **Faults -** Remove DSG in < 1 second for utility fault

6) **Power factor -** ≥ .85

VIII. Dangerous Levels of Current

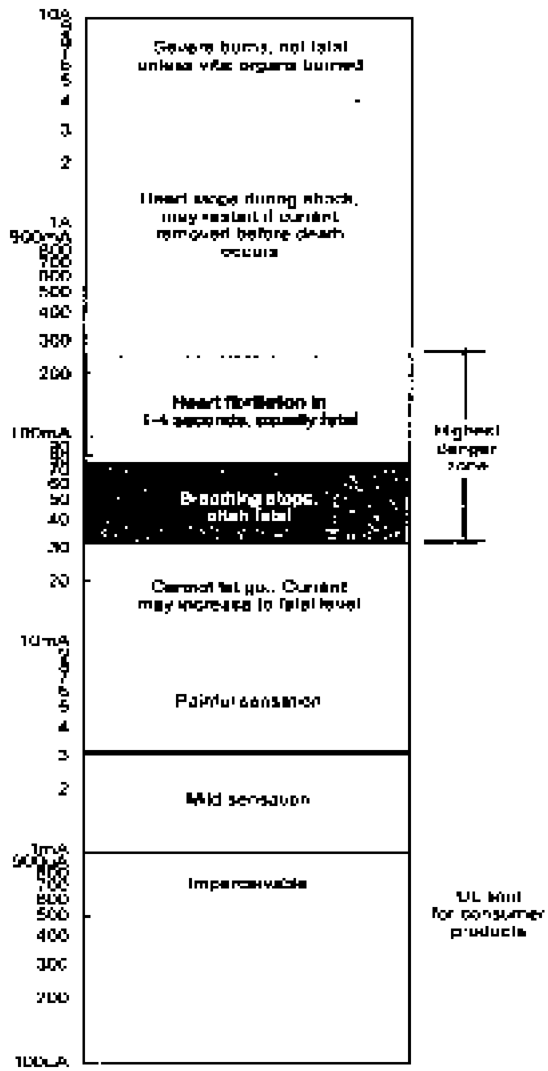


Figure 14. Effect of Current on Humans

IX. Capacitor Formulas

Nomenclature: C = Capacitance in μF

V = Voltage
A = Current
K = 1000

1) Capacitors connected in parallel: $C_{Total} = C_1 + C_2 + C_3 + --$

2) Capacitors connected in series:

$$C_{Total} = \frac{C_1 \times C_2}{C_1 + C_2}$$

For two capacitors in series

$$C_{Total} = \frac{1}{\frac{1}{C_1} + \frac{1}{C_2} + \frac{1}{C_3} + --}$$

For more than two capacitors in series

3) Reactance – X_c (Capacitive)

a. $$X_c = \frac{10^6}{(2\pi f)C}$$

b. $$X_c = \frac{2653}{C}$$ at 60HZ (1μF = 2653 Ω)

b. $$X_c = \frac{KV^2 \times 10^3}{KVAR}$$

4) Capacitance – C

a. $$C = \frac{10^6}{(2\pi f)\, X_c}$$

b. $$C = \frac{KVAR \times 10^3}{(2\pi f)(KV)^2}$$

5) Capacitive Kilovars

a. $$KVAR = \frac{(2\pi f)C\,(KV)^2}{10^3}$$

b. $$KVAR = \frac{10^3\,(KV)^2}{X_c}$$

6) Miscellaneous

a. Power Factor = $\cos\theta \quad \dfrac{KW}{KVA}$

$\tan\theta \quad \dfrac{KVAR}{KW}$

X. European Practices

A. Primary

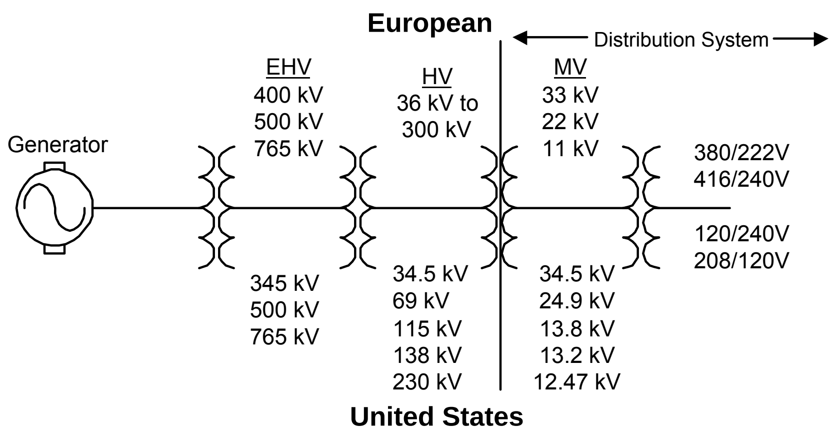


Figure 15. European / US Voltage Levels

Secondary

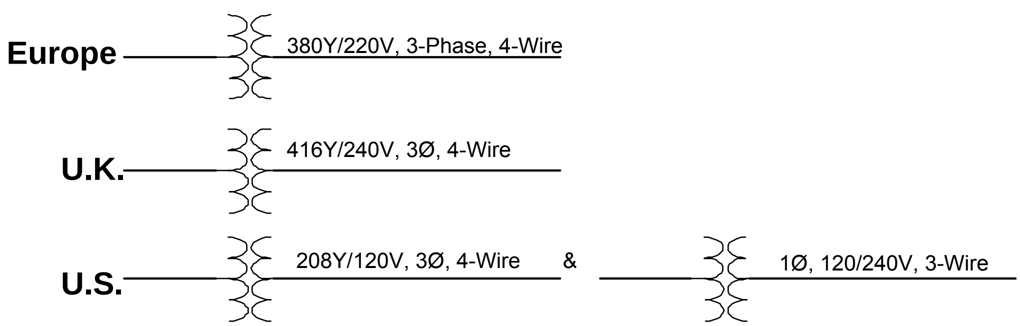


Figure 16. European Secondary

B. Relays

- TMS - Time multiplier setting (similar to time dial)
- CTU - Earth fault relay set between 1 % and 16 % of rated current
- CDG 11 - Standard overcurrent relay
- CDG 13 - Very inverse
- CDG 14 - Extremely inverse relay
- CTU 12 - Definite time relay

C. Earth Fault Protection

- Based on the premise that all loads are 3 phase and balance
- Considers the effect of line capacitance mismatch
- Uses residual current

D. General

- Autoreclosure on overhead is normal
- Use normally open loop most of the time
- Even on a 3-wire system there may be some unbalance due to capacitors which must be considered when setting the earth relay
- Conventional relays will not operate for unearthed systems
- For ungrounded systems:
  - current and voltage unbalance must exceed a predetermined amount
  - phase angle must occur within a specified range (makes capacitor application difficult)
  - I (fault) is highly influenced by the capacitance of the network
- Maximum fault levels allowed are:

Table 7

kV	kA
33	25
22	20
11	20

- 11-kV system is mostly radial and underground
- 33-kV system is looped and mostly underground
- Most 4l5-volt transformers are l00 kVA or less and about 50% loaded

Table 8 - Distribution System Design Comparison

U.S.	Europe
120/240	380 Wye/220, 4-wire. 416 Wye/240, 4-wire (UK)
1-phase transformers heavily overloaded – 25 kVA typical.	Less load per home than U.S.
4 homes/transformer fairly typical	3-phase xfrms >> $ 1-phase
Higher load density	Residential units in 300-500 kVA range
Fuses are typically expulsion	5 to 10 radial, 3-phase, 4-wire secondary feeds, per transformer
	No overload
	Fuses are current limiting
	100 to 200 dwellings per transformer

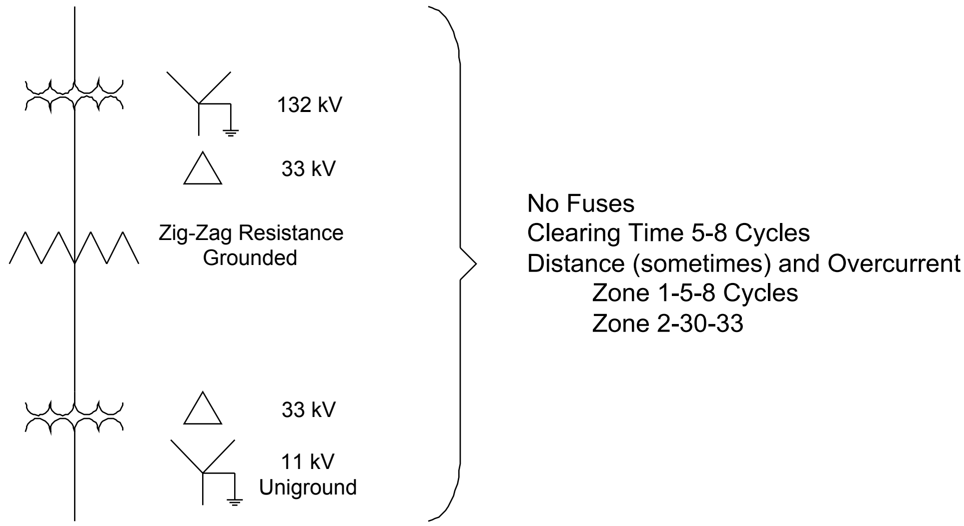


Figure 17. 33 kV/11 kV Distribution

XI. Power Quality Data

A. Momentaries

Typical number of customer momentaries caused by the utility system ≈ 5
Typical number of customer momentaries for all causes ≈ 10

B. Sags

Typical number of customer sags caused by the utility system ≈ 50
Typical number of customer sags for all causes ≈ 350
**Voltage below .9 PU of nominal*

C. Power Quality Organizations

Committee/Standard	Activity
Characterizing Power Quality/Power Quality Indices/General Power Quality	
Power Quality Standards coordinating committee SCC-22	Coordinates all power quality standards activities
IEEE 1159 Monitoring Power Quality	A number of task forces addressing different aspects of power quality monitoring requirements and definitions
IEEE 141 Red Book	General guidelines for industrial commercial power systems
IEEE 241 Gray Book	General guidelines for commercial power systems
Harmonics	
IEEE P519A	Developing application guide for applying harmonic limits
Filter Design Task Force	Guidelines for harmonic filter design
Task Force on Harmonic Limits for Single Phase Equipment	Developing guidelines for applying harmonic limits at the equipment level
Voltage Sags/Momentary Interruptions	
IEEE 493 Gold Book	Industrial and commercial Power system Reliability
IEEE 1346	Evaluating compatibility of power systems for industrial process controllers
Steady State Regulation, Unbalance, and Flicker	

ANSI C84.1	Voltage rating for power systems and equipment
IEEE Flicker Task Force	Developing a coordinated approach for characterizing flicker
Wiring and Grounding/Powering Sensitive Equipment	
IEEE 1100 Emerald Book	Guidelines for powering and grounding sensitive equipment
National Electric Code	Safety requirements for wiring and grounding
IEEE 142 Green Book	Industrial and commercial Power System grounding
Transients	
OEEEA NSI C62	Guides and standards on surge protection
Distribution Systems/Custom Power Solution	
IEEE 1250 Distribution Power Quality Working Group	Guide on equipment sensitive to momentary voltage variations
IEEE 1409 Custom Power Task Force	Developing guidelines for application of power electronics technologies for power quality improvement on the distribution system

D. Categories and Typical Characteristics of Power System Disturbances

Table 9

Categories		Typical Duration	Typical Voltage Magnitude
Transients	Impulsive	nsec to msec	na
	Oscillatory	3 msec	0.8 pu
Short Duration Variations	Instantaneous Sag	.5 – 30 cycles	0.1 – 0.9 pu
	Instantaneous Swell	.5 – 30 cycles	1.1 – 1.8 pu
	Momentary Interruption	0.5 cycles – 3 sec	Less than 0.1 pu
	Momentary Sag	30 cycles – 3 sec	0.1 – 0.9 pu
	Momentary Swell	30 cycles – 3 sec	1.1 – 1.4 pu
	Temporary Interruption	3 sec – 1 min	Less than 0.1 pu
	Temporary Sag	3 sec – 1 min	0.1 – 0.9 pu
	Temporary Swell	3 sec – 1 min	1.1 – 1.4 pu
Long Duration Variations	Sustained Interruption	Longer 1 minute	0.0 pu
	Undervoltage	Longer 1 minute	0.8 – 0.9 pu
	Overvoltage	Longer 1 minute	1.1 – 1.2 pu
Voltage Imbalance		Steady state	.5 – 2%
Waveform Distortion	DC Offset	Steady state	.05 – 2%
	Harmonics	Steady state	0 – 20%
	Inter-harmonics	Steady state	0 – 20%
	Notching	Steady state	NA
	Noise	Steady state	0 – 1%
Voltage Fluctuations		Intermittent	0.1 – 7%
Power Frequency Variations		Less than 10 sec	NA

XII. Electricity Rates

Table 10

For Medium Size Commercial and Industrial		
Utility	**Commercial $/kWh**	**Industrial $/kWh**
A	$0.1067	$0.0899
B	$0.1761	$0.0732
C	$0.1672	$0.1058
D	$0.1482	$0.0998
E	$0.1328	$0.1039
F	$0.1279	$0.0720
G	$0.1690	$0.0950

Table 11

Twelve Most Expensive Companies Investor-Owned Electric Utilities			
		Dec.'91 - Feb.'92	
Company	**State**	**Avg. Cost $/kWh***	**National Rank**
Long Island Lighting Co.	New York	$0.156	1
Philadelphia Electric Co.	Pennsylvania	$0.152	2
Pennsylvania Power Co.	Pennsylvania	$0.148	3
Duquesne Light Co.	Pennsylvania	$0.146	4
Consolidated Edison Co.	New York	$0.137	5
Western Mass. Electric Co.	Massachusetts	$0.137	6
Hawaii Electric Co.	Hawaii	$0.136	7
Nantucket Electric Co.	Massachusetts	$0.135	8
Commonwealth Electric Co.	Massachusetts	$0.131	9
Orange & Rockland Utilities Inc.	New York	$0.130	10
Citizens Utilities Co. – Kauai Div.	Hawaii	$0.125	11
United Illuminating Co.	Connecticut	$0.124	12
*For monthly residential sales of 500 kWh.			
Source: National Association of Regulatory Utility Commissioners			

Table 12

Twelve Least Expensive Companies Investor-Owned Electric Utilities			
		Dec.'91 - Feb.'92	
Company	**State**	**Avg. Cost $/kWh***	**National Rank**
Washington Water Power Co.	Idaho	$0.041	191
Pacific Power & Light Co.	Washington	$0.043	192
Washington Water Power Co.	Washington	$0.044	189
Idaho Power Co.	Oregon	$0.047	188
Idaho Power Co.	Idaho	$0.047	187
Kentucky Utilities Co.	Kentucky	$0.051	186
Portland General Elec. Co.	Oregon	$0.052	185
Puget Sound Power & Light Co.	Washington	$0.053	184
Potomac Electric Power Co.	Dist. of Col.	$0.054	183
Minnesota Power & Light Co.	Minnesota	$0.054	182
Pacific Power & Light Co.	Oregon	$0.055	181
Kingsport Power Co.	Tennessee	$0.056	180

*For monthly residential sales of 500 kWh.

Source: National Association of Regulatory Utility Commissioners

XIII. Costs

A. General

1) Annual system capacity:

Generation:	$ 704/kW
Transmission:	$ 99/kW
Distribution:	$ 666/kW
Total:	$1469/kW

2) Cost of capacitors (installed)

Substations:	$ 9/kVAR
Line:	$ 5.5/kVAR
Padmounted:	$ 21/kVAR

3) Transformers (installed)

a. Single phase padmounts (installed)

	12.5 kV (loop feed)	34.5 kV (loop feed)
25 kVA	$2552	$3119
50 kVA	$2986	$3931
75 kVA	$3591	$4725
100 kVA	$4972	$5728

b. Three Phase Padmounts

	12.5 kV (loop feed)	34.5 kV (loop feed)
75 kVA	$ 7,749	$10,584
150	$ 9,450	$11,605
300	$11,718	$15,574
500	$13,608	$20,034
750	$21,357	$21,377
1000	$25,515	$28,350
1500	-	$40,824
2500	-	$50,841

NOTE: Above costs include necessary cable terminations, pads, misc. material and transformer, but no primary or secondary cable.

4) Substation costs (includes land, labor, and material)

a.	115-13.2kV, 20/37.3 MVA, 4 feeder substation	$3,348,000
b.	35-12.5 kV, 12/16/20 MVA, 2 feeder substation	$1,026,000
c.	115-35kV, 60/112 MVA, 5 feeder substation	$4,050,000
d.	230-13.2 kV, 27/45 MVA, 5 feeder substation	$3,960,000
e.	230-34.5 kV, 60/112 MVA, 5 feeder substation	$5,040,000

5) Miscellaneous costs:

a. Cable (approximate)

- Mainline, conduit $ 90/ft
- Mainline, D.B. $ 38/ft
- Lateral, conduit $ 63/ft
- Install transformer $ 2,698
- Change out transformer $ 2,822
- Install - 3∅ switch $ 20,871
- Replace - 3∅ switch $ 11,203
- Install - 1∅ fuse switch $ 11,367

6) Cost of replacing cable:

a. 1∅ - $180/ft.
b. 3∅ - $360/ft.

7) Elbows (installed) - $111 each

XIV. Reliability Data

Table 13

Failure Rate Data	
Component	**Failure Rate**
Primary Cable (polyethylene)	6/100 mi-yr (conductor miles)
Secondary Cable (polyethylene)	10/100 mi-yr (circuit miles)
Transformers, single phase, padmounted	0.4%/yr
Transformers, three-phase, padmounted	0.62%/yr
Transformers, single phase, subsurface	0.3%/yr
Switches, oil, subsurface	0.12%/yr
Switches, air, padmounted	0.12%/yr
Fuse cabinet, single phase, padmounted	0.1%/yr
Fuse cabinet, three-phase, padmounted	0.2%/yr
Primary splices, rubber molded	.01%/yr
Elbows:	
Rubber molded, loadbreak	.06%/yr
Rubber molded, non-loadbreak	.06%/yr
Tees, 600 amp	.02%/yr

Typical values for customer based indices are:

- **SAIDI - 96 min/yr.**
- **SAIFI - 1.18 interruptions/yr.**
- **CAIDI - 81.4 min/yr.**

XV. Industrial and Commercial Stuff

Introduction

Utility engineers have historically needed to know a lot about their own system and very little about their customers system and loads. Competitive times and the emphasis on power quality have forced the utility engineer to venture to the "other side of the meter" to address the power related concerns and problems of specific industrial processes and components. The purpose of this section is to address some of the more commonly encountered terminology, equipments and problems that the utility distribution engineer generally has a hard time finding.

Motors

a. Major Categories of Motors

Alternating Current Types

Three-Phase

Induction
Synchronous

Single-Phase

Induction-Run, Capacitor Start
Induction-Run, Split Phase Start
Shaded-Pole
Universal (Commutator)
Repulsion

Direct Current Types

Shunt-Characteristic:	Electromagnetic Field
Shunt-Characteristic:	Permanent Magnet Field
Series-Characteristic:	Series Field Only
Compound Wound	

b. **KVA/Hp Conversions (at full load)**

	KVA / HP
Induction 1 - 100 Hp	1.0
Induction 101 - 1000 Hp	0.95
Induction > 1000 Hp	0.9
Synchronous 0.8 pf	1.0
Synchronous 0.9 pf	0.9
Synchronous 1.0 pf	0.8

c. Reduced-voltage Starters

Table 14

Reduced-Voltage Starter Type	Line Current As % Of Full-Voltage Starting
Autotransformer – 50% tap	30%
Autotransformer – 65% tap	47%
Autotransformer – 80% tap	69%
Wye-delta	33%
Part-Winding	70%
Primary Resistor – 80% tap	80%

Primary Resistor – 65% tap	65%

d. Characteristics of Motors

DC Motors

- **Advantage of DC Motor** is that the torque-speed characteristic can be varied over a wide range and still have high efficiency
- **3 Basic Types -** Shunt, Series and Compound
- **Shunt -** In this motor the field current is independent of the armature having been diverted (shunted) through its own separate winding. Increasing the field current actually causes the motor to slow down. Torque and power however are higher.
- **Series -** The series motor is identical in construction to the shunt motor except the field is connected in series with the armature. At startup, armature current is high, so flux is high and torque is high. If load decreases, speed goes up. Series motors are for high torque, low speed applications such as the starter motor of a car or the motors used for electric locomotives.
- **Compound -** A compound motor carries both a series field and a shunt field**.** The shunt field is always stronger. As load increases, the shunt field remains the same but the series field increases. At no load it looks like a shunt motor.

The diagram shown below illustrates the basic characteristics of these motors:

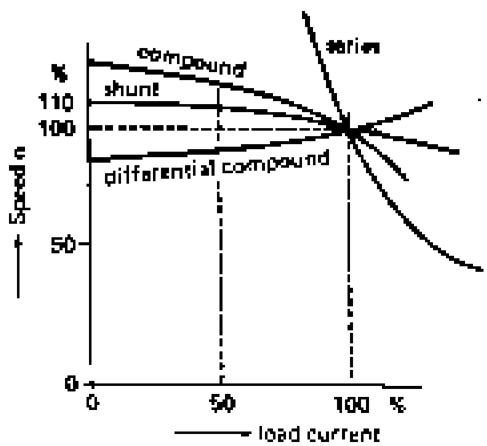


Figure 18 - Typical speed versus load characteristics of various dc motors

Induction Motors

- Most frequently used in industry (simple, rugged and easy to maintain)
- Essentially constant speed from 0 to full load
- Not easily adapted to speed control
- Parts:
  - Stationary stator
  - Revolving rotor (slip ring at end)
  - Conventional 3 phase winding
  - Squirrel-cage windings (copper bars shorted at end)

The characteristics of the induction motor are illustrated below:

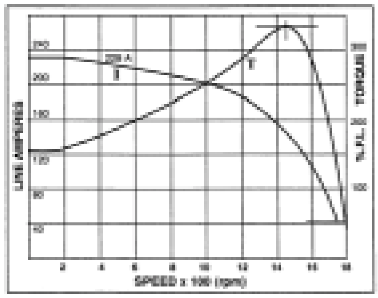


Figure 19

Synchronous Motors

- The most obvious characteristic of a synchronous motor is its strict synchronism with the power line frequency.
- Its advantage to the industrial user is its higher efficiency and low cost in large sizes
- Biggest disadvantage is added complications of motor starting.
- A synchronous motor is identical to a generator of the same rating.
- Synchronous motors are only selected for applications with relatively infrequent starts since starting is more difficult and usually requires the use of induction (squirrel cage) motor.

e. **Adjustable-Speed Drives**

- Adjustable speed drives have the **advantage** of being both efficient and reliable
- Used for compressors, pumps, and fans that have variable-torque requirements
- **Six basic types:**
  - DC drive with DC motor
  - Voltage-source inverter with induction motor
  - Slip-energy recovery system with wound-rotor motor
  - Current-source inverter with induction motor
  - Load-commutated inverter with synchronous motor
  - Cycloconverter drive for either a synchronous or an induction motor

The figure, shown below, is a one line diagram for a typical current-source inverter. The current-source inverter has a phase controlled rectifier that provides a DC input to a six-step inverter. The reactor provides some filtering. Control of the inverter serves to regulate current and frequency, rather than voltage and frequency as with the voltage-source inverter.

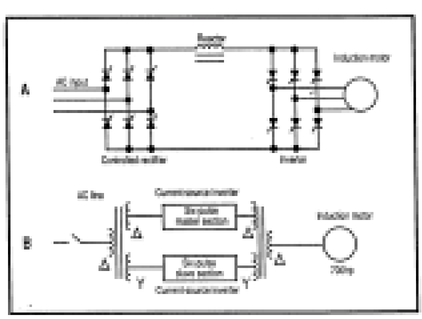


Figure 20 – Typical current-source inverter (A) and one with a 12-pulse power conversion unit (B) required by larger motors

XVI. Maxwell's Equations

When in doubt, you can always go back and derive whatever you need to know using Maxwell's equations (that's what my professor told me ……. right!!!!!!!!) So here goes:

Gauss' law for electric fields

$$\oiint E \bullet dA = \frac{Q}{\varepsilon_0}$$

Gauss' law for magnetic fields

$$\oiint B \bullet dA = 0$$

Generalized Ampere's law

$$\oint B \bullet ds = \mu_0 I + \mu_0 \varepsilon_0 \frac{d}{dt} \iint_s E \bullet dA$$

Faraday's law

$$\oint E \bullet ds = -\frac{d}{dt} \iint_s B \bullet dA$$

Got that!!!!!!!!

EXPERIENCE

Mr. Burke joined ABB in 1997 as an Institute Fellow at ABB's Electric systems Technology Institute. He is recognized throughout the world as an expert in distribution protection, design, power quality and reliability.

Mr. Burke began his career in the utility business with the General Electric Company in 1965 training and taking courses in generation, transmission and distribution as part of GE's Advanced Utility Engineering Program. In 1969, he accepted a position as a field application engineer in Los Angeles responsible for transmission and distribution system analyses, as well as generation planning studies for General Electric's customer utilities in the Southwestern states. In 1971 he joined GE's Power Distribution Engineering Operation in New York where he was responsible for distribution substations, overcurrent and overvoltage protection, and railroad electrification for customers all over the world. During this period he was involved with the development of the MOV "riser pole" arrester, the Power Vac Switchgear, the static overcurrent relay and distribution substation automation.

In 1978 Mr. Burke accepted a position at Power Technologies Inc. (PTI) where he continued to be involved with virtually all distribution engineering issues. During this period he was responsible for the EPRI distribution fault study, the development of the first digital fault recorder, state-of-the-art grounding studies, and numerous lightning and power quality monitoring studies. In the area of railroad electrification he was co-author of the EPRI manual on "Railroad Electrification on Utility Systems" as well as project manager of system studies for the 25 to 60 Hz conversion of the Northeast Corridor. Until his departure in 1997, he was manager of distribution engineering.

JAMES J. BURKE

Institute Fellow

He has authored and co-authored over 85 technical papers, including two prize papers. He is the author of the book “Power Distribution Engineering: Fundamentals & Applications”. He is author of the last two revisions to the chapter on Distribution Engineering in the "Standard Handbook for Electrical Engineering."

EDUCATION

BSEE - Univ. of Notre Dame
MSIA – Union College – Thesis: “Reliability and Availability Analysis of Direct Buried Distribution Systems”
PSEC – GE (Schenectady)

PROFESSIONAL ACTIVITIES

IEEE
Chair: Dist. Neutral Grounding
Chair: Voltage Quality
Past Chair: Dist. Subcommittee
Member – T&D Committee
Member–Surge Protective Device Committee

ACHIEVEMENTS & HONORS

IEEE
Fellow (1992)
Standards Medallion (1992)
2 Prize Papers
The 1996 Award for:
“Excellence in Power Distribution Engineering”
Distinguished Lecturer in Power Quality

Technical Papers

G.E.

1. **"An Availability and Reliability Analysis of Direct Buried** and Submersible Underground Distribution Systems," *IEEE Transactions* Conference paper, Underground Conference Detroit, Mich., June 1970 (co-author: R. H. Mann)
2. "How Do You Serve 3 Phase Loads Underground," *Electrical World,* June 1970 (co-authors: R. H. Mann, and F. Tabores).
3. "Railroad Electricification" *Electric Forum Magazine,* June 1976 (co-author: J. H. Easley).
4. "Surge Protection of Underground Transformers", *Electric Forum Magazine,* August 1976.
5. "An Analysis of Distribution Feeder Faults", *Electric Forum Magazine,* December 1976 (co-author: D. J. Ward)
6. "Doubling the Capacity of the Black Mesa and Lake Powell Railroad," *Electric Forum Magazine,* November 1978 (co-author: S. Gilligan).
7. "Protecting Underground Systems with Zinc Oxide Arresters," *Electric Forum Magazine"*, November 1979 (co author: S. Smith)
8. "A Comparison of Static and Electromechanical Time Overcurrent Relay Characteristics, Application and Testing," Philadelphia Electric Association, June 1975 (co-authors: R. F. Koch and L. J. Powell).
9. "Distribution Substation Practices", (two volumes), presented at Quito, Ecuador, June 1975.
10. "Distribution System Feeder Overcurrent Protection", GET-6450, June 1977. Also presented as a seminar in the US and Latin America.
11. "Surge Protection of Underground Systems up to 34.5 kV," presented at Underground Conference in Atlantic City, NJ. September 1976 (co-authors: N.R. Schultz, E.G. Sakshaug and N. M. Neagle).
12. "Railroad Electricification from a Utility Viewpoint." Philadelphia Electric Association, May 1977.
13. "Increasing the Power System Capacity of the 50 kV Black Mesa and Lake Powell Railroad Through Harmonic Filtering and Series Compensation," *IEEE Transactions* paper presented at 1978 IEEE Summer Power Meeting, Paper No. F79 284-1 (co-authors: A.P. Engel, S.R. Gilligan and N.A. Mincer).
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15. "Type NLR & NSR Reclosing Relays – An Analysis of VEPCO's 34.5 kV Distribution Feeder Faults as Related to Through Fault Failures of Substation Transformers," General Electric Publication GER-3063, March, 1978 (co-authors: L. Johnston, D. J. Ward, and N. B. Tweed).
16. "The Application of Gapless Arresters on Underground Distribution Systems," *IEEE Transactions* Paper No. F79 636-2, Vancouver, British Columbia, July 1979, T&D Conference and Exposition (co-author: S. Smith and E.G. Sakshaug).
17. Guide for "Surge Protection of Cable-Connected Equipment on Higher Voltage Distribution Systems," (SPD Working Group, *IEEE Transactions* paper presented at the 1979 T&D Conference and Exposition.

PTI

18. "Study Defines Surges in Greater Detail", *Electrical World,* June 1, 1980.
19. "A Study of Distribution Feeder Faults Using a Unique New Recording Device," Western Underground Meeting, Portland, September 1980.
20. "25 to 60 Hz Conversion of the New Haven Railroad," *IEEE Transactions* Paper presented at IEEE/ASME Joint Conference, Baltimore, May 1983 (co-authors: D.A. Douglass and P. Kartluke).
21. "Characteristics of Faults, Inrush and Cold Load Pickup Currents in Distribution Systems," presented to the Pennsylvania Electric Association, May, 1983.
22. "Characteristics of Fault Currents on Distribution Systems", presented at the IEEE Summer Power Meeting in July, 1983 *IEEE Transactions* Paper No. 83 SM 441-3 (co-author: D.J. Lawrence).
23. "Optimizing Performance of Commercial Frequency Electrified Railroads," presented in New York City in May, 1985 at the IEEE Transportation Division Meeting.
24. "Compensation Techniques to Increase Electrified Railroad Performance," *IEEE Transactions,* presented at the IEEE/ASME Joint Conference, Norfolk, VA, April, 1986.
25. "Factors Affecting the Quality of Utility Power, APPA Conference, May 28, 1986, Colorado Springs, CO.
26. "Fault Impedance Considerations for System Protection", presented at the T&D Conference, Anaheim, CA, September 1986
27. "Cost/Benefit Analysis of Distribution Automation," presented at the American Power Conference, Chicago, IL, April 1987
28. "The Effect of Higher Distribution Voltages on System Reliability," Panel Session, IEEE Summer Power Meeting, San Francisco, CA, 1987.
29. "Are Distribution Overvoltage Margins Inadequate?," Western Underground Meeting, January 1988.
30. "Utility Operation and Its Effect on Power Quality," IEEE Winter Power Meeting Panel Session, February 1988.
31. "Higher Distribution Voltages… Not Always a Panacea," *Electrical World,* April 1988.
32. "Distribution Systems, Reliability, Availability and Maintainability," IMEA Summer Conference for Utilities, June 1988, (co-author: R.J. Ringlee).
33. "Why Underground Equipment is Failing on Overvoltage," *Electrical World,* July 1988.
34. "Cost/Benefit Analysis of Distribution Automation: Evaluation and Methodology," T&D Automation Conference Exposition, St. Louis, MO, September 1988 (Part II).
35. "Improper Use Can Result In Arrester Failure," *Electrical World,* December 1988.
36. "Metal Oxide Arresters on Distribution Systems: Fundamental Considerations," *IEEE Transactions*, presented at the IEEE PES Winter Meeting, New York, NY, February 1989, (Co-authors: E.G. Sakshaug and J. Kresge). [1991 SPD Prize Paper Award].
37. "The Effect of Switching Surges on 34.5 kV System Design and Equipment," *IEEE Transactions*, presented at the IEEE/PES T&D Conference and Exposition, New Orleans, LA, April 1989, (Co-authors: J. W. Feltes and L.A. Shankland).
38. "The Application of Surge Arresters on Distribution Systems", Power Distribution Conference, Austin, TX, October 1989.
39. "Application of MOV and Gapped Arresters on Non Effectively Grounded Distribution Systems, "*IEEE Transactions,* Paper No. 90 WM 136-2 PWRD, presented at the IEEE PES Winter Meeting, Atlanta, A, February 4-8, 1990, (Co-authors: V. Varneckas, E. Chebli, and G. Hoskey).
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41. “Power Quality Measurements on the Niagara Mohawk Power System,” presented at the 1990 Chattanooga IEEE Section’s Power Quality Seminar, April 18, 1990, (Co-authors: P.P. Barker, R.T. Mancao, and C. Burns).

42. “Constraints on Mitigating Magnetic fields on Distribution Systems,” Panel Session, IEEE PES Summer Power Meeting, Minneapolis, MN, July 16-20, 1990.

43. “The Effect of Lightning on the Utility Distribution System”, presented at the 12th Annual Electrical Overstress/Electrostatic Discharge Symposium, Orlando, FL September 11, 1990.

44. “Power Quality Measurements on the Niagara Mohawk Power System… Revisited,” presented at the PCIM/Power Quality ’90 Seminar, Philadelphia, PA, October 21-26, 1990, (co-authors: P.P. Barker, R. T. Mancao, C. W. Burns, and J.J. Siewierski).

45. “Protecting Underground Distribution” *Electric Light & Power*, April 1991, (co-author: P.P. Barker).

46. “Utility Distribution System Design and Fault Characteristics,” Panel Session, 1991 IEEE T&D Conference and Exposition, Dallas, TX, Sept. 23-27, 1991.

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48. “Controlling Magnetic Fields in the Distribution System,” *Transmission and Distribution*, December 1991, pp. 24-27.

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54. “IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part IV – Distribution,” published by IEEE, 1992, (prepared by the Working Group on the Neutral Grounding of Distribution Systems of the IEEE Surge-Protective Devices Committee, J.J. Burke, Chairman).

55. “Application of MOV’s in the Distribution Environment,” presented at the IEEE Transactions Power Delivery, Vol. 9, No. 1, Pages 293-305 – Jan. ’94 .

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63. “Hard to Find Information About Distribution Systems,” presented at PTI’s Power Distribution Course, Sacramento, CA, March 1995.

64. “Sensitivity and Selectivity of Overcurrent Protective Devices on Distribution Systems (or, Now You See It…Now You Don’t), Panel Session, 1995 IEEE Summer Power Meeting, Portland, OR July 23-28, 1995.

65. “Tutorial on Lightning and Overvoltage Protection,” presented at the 1995 Power Distribution Conference, Austin, TX October 24, 1995.

66. “Analysis of Voltage Sag Assessment of Frequency of Occurrence and Impacts of Mitigations,” presented at Conference on Electrical Distribution, January 9-10, 1996, Kuala Lumpur, Malaysia, (co-authors: S. Yusof, J.R. Willis, P.B. Steciuk, T.M. Ariff and M. Taib).

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68. “Application of Surge Arresters to a 115-kV Circuit,” presented at the 1996 Transmission and Distribution Conference & Exposition, Los Angeles, CA, September 16-20, 1996, (co-authors: C.A. Warren, T. A. Short, C. W. Burns, J.R. Godlewski, F. Graydon, H. Morosini).

69. “Fault Currents on Distribution Systems,” panel session paper presented at 1996 Transmission and Distribution Conference and Exposition, Los Angeles, CA, September 16-20, 1996.

70. “Philosophies of Distribution System Overcurrent Protection,” Training Session on “Distribution Overcurrent Protection and Policies,” 1996 Transmission and Distribution Conference & Exposition, Los Angeles, CA, September 16-20, 1996.

71. “A Summary of the Panel Session: Application of High Impedance Fault Detectors: Held at the 1995 IEEE PES Summer Meeting,” presented at 1996 Summer Power Meeting, Denver, Colorado, July 28-August 2, 1996, (co-authors G.E. Baker, J.T. Tengdin, B. D. Russell, R. H. Jones, T. E. Wiedman).

72. “Philosophies of Overcurrent Protection for a Five-Wire Distribution System,” panel session paper presented at 1996 Transmission and Distribution Conference and Exposition, Los Angeles, CA, September 16-20, 1996 (co-author P.B. Steciuk).

73. “Utility Characteristics Affecting Sensitive Industrial Loads,” Power Quality Assurance Magazine, Nov./Dec. 1996.

74. “Fundamentals of Economics of Distribution Systems,” IEEE PES Winter Power Meeting, New York City, February 1997.

ABB

75. “Techniques and Costs to Improve Power Quality,” the EEI Power Quality Working Group, New Orleans, March, 1997.

76. “Trends in Distribution Reliability,” University of Texas Power Distribution Conference, October 1997.

77. “System and Application Considerations for Power Quality Equipment in Distribution,” EEI Distribution Committee Meeting, Baltimore, MD, October 1997.

78. “Hard to Find Information about Distribution Systems – Revisited” – June 1998, ABB.

79. "Power Quality at Champion Paper - The Myth and the Reality", IEEE Transaction, Paper #PE-340-PWRD-0 -06-1998, (Co-Authors: C.A. Warren, T.A. Short, H. Morosini, C.W. Burns, J. Storms)

80. "Delivering Different Levels of Service Reliability Over a Common Distribution System" T + D World Conference, Arlington VA, September 29 1998.

81. "European vs. U.S. Distribution System Design," 1999 WPM, N.Y.C. (co-author S. Benchluch)

Technical Papers

82. "Managing the Risk of Performance Based Rates," 1999, (co-author R. Brown). IEEE Transactions, May 2000, volume 15, pages 893-898.
83. "Application of Reclosers on Future Distribution Systems," (co-author R. Smith) – BSS Meeting in Greensboro N.C., Jan. 1999.
84. "Serving Rural Loads from Three Phase and Single Phase Systems," (co- authors S. Benchluch, A. Hanson, H. L. Willis, H. Nguyen, P. Jensen).
85. Standard Handbook for Electrical Engineers, 14^{th} edition, McGraw Hill, 1999.
86. "Hard to Find Information About Distribution Systems," Third Revision, June 1999.
87. "Trends in Distribution Reliability in the United States," CIRED, Nice, France, June 1999.
88. "Reclosers Improve Power Quality on Future Distribution Systems," T & D Conference, New Orleans, 1999
89. "Distribution Impacts of Distributed Resources," SPM – 1999, Alberta, Canada.
90. "Requirements for Reclosers on Future Distribution Systems," Power Quality Assurance Magazine, July 1999
91. "Fault Impedance…How Much?" – T & D World Magazine.
92. "A Systematic and Cost Effective Method to Improve Distribution System Reliability," (co-authors H. Nguyen, R. Brown) IEEE SPM - 1999, Edmonton, Alberta.
93. "Rural Distribution System Design Comparison," (co-authors: H. Nguyen, S. Benchluch)- IEEE, WPM 2000, Singapore.
94. "Improving Distribution Reliability Using Outage Management Data," (co-author: J. Meyers) presented at DistribuTECH 2000, Miami, Florida.
95. "Distribution Impacts of Distributed Generation – Revisited," panel session at DistribuTECH 2000, Miami, Florida.
96. " Maintaining Reliability In a De-regulated Environment," T&D World 2000, April 26-28, Cincinnati, Ohio.
97. "Using Outage Data to Improve Reliability" IEEE Computer Applications in Power" magazine, April 2000, (Volume 13, Number 2)
98. "Utilities Take on Challenges or Improved Reliability and Power Quality" Electric Light and Power Magazine, Vol.78, Issue6, June 2000
99. "Determining the Optimum Level of Reliability" Infocast Reliability Seminar, September 27, 2000, Chicago
100. "Hard-to-Find information on Distribution Systems, Part II - The New Millennium, November 2000.
101. "Determining the Optimum Level of Reliability – Revisited" IEEE T&D Conference 2001, Atlanta, Ga.
102. "Trends Creating Reliability Concerns or 10 Steps to Becoming a Less Reliable Utility" IEEE T&D Conference 2001, Atlanta, Ga.
103. "Distribution Systems Neutral Grounding" (co-author M. Marshall) IEEE T&D Conference 2001, Atlanta, Ga.
104. "Distribution Automation" A compilation prepared for the Intensive Distribution Planning and Engineering Workshop, September 24-28, Raleigh, NC.
105. "How Important is Good Grounding on Utility Distribution Systems? PQ Magazine - April 02 – (co-author M. Marshall)