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Design Guide for Rural Substations

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UNITED STATES DEPARTMENT OF AGRICULTURE
Rural Utilities Service

RUS BULLETIN 1724E-300

SUBJECT: <u>Design Guide for Rural Substations</u>

TO: All RUS Borrowers
RUS Electric Staff

EFFECTIVE DATE: Date of approval.

OFFICE OF PRIMARY INTEREST: Transmission Branch, Electric Staff Division.

INSTRUCTIONS: This bulletin is an update and revision of previous REA Bulletin 65-1, "Design Guide for Rural Substations" (revised June 1978). Replace previous Bulletin 65-1 with this bulletin and file with 7 CFR Part 1724.

AVAILABILITY: This bulletin is available on the Rural Utilities Service website at:

http://www.usda.gov/rus/electric

PURPOSE: This bulletin provides a basic design guide and a reference tool for designing rural substations.

GENERAL: This Bulletin has been revised to bring the publication up to date with latest industry standards, current RUS format, and technical requirements.

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6/7/01
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ABBREVIATIONS AND ACRONYMS

"	Inches
%	Percentage
ρ	Resistivity
°C	Degrees Celsius
°F	Degrees Fahrenheit
μs	Microseconds
2D	Two Dimensional
3D	Three Dimensional
A	Amperes
AASHTO	American Association of State Highway and Transportation Officials
AC	Alternating Current
ACI	American Concrete Institute
ACR	Automatic Circuit Recloser
ACSR	Aluminum Conductor Steel Reinforced
ADSC	Association of Drilled Shaft Contractors
ADSS	All-Dielectric Self-Supporting
AEIC	Association of Edison Illuminating Companies
AEP	American Electric Power
AFOW	Arrester Front of Wave
AIEE	American Institute of Electrical Engineers
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
ASCE	American Society of Civil Engineers
ASD	Allowable Stress Design
ASTM	American Society for Testing and Materials
ASYM	Asymmetrical
ATM	Asynchronous Transfer Mode
AWG	American Wire Gage
BIL	Basic Impulse Insulation Level
BOCA	Building Officials and Code Administration
BSL	Basic Switching Impulse Insulation Level
CADD	–Computer-Aided Design and Drafting
CC	Coupling Capacitor
CCVT	Coupling Capacitor Voltage Transformer
CFR	Code of Federal Regulations
cm	Centimeter
COG	Coefficient of Grounding
CPM	Critical Path Method
Cpt	Cap and Pin Type
CPU	Central Processing Unit
CSMA/CD	Carrier Sense Multiple Access with Collision Detection
CRN	Cooperative Research Network
CT	Center Tap; Current Transformer
Cu	Copper
CVT	Capacitor Voltage Transformer
CWW	Chopped Wave Withstand
dB	Decibels

dBA	Decibels above 1 ampere
DC	Direct Current
DCE	Data Communications Equipment
Dist.	Distribution
DOT	Department of Transportation
DS1	Digital Signal Level 1
DTE	Data Terminating Equipment
DTM	Digital Terrain Model
DV	Discharge Voltage
E	Modulus of Elasticity
EA	Environmental Assessment
ECSA	Exchange Carrier Standards Association
EHV	Extra High Voltage
EMF	Electromagnetic Force; Electromotive Force
EMTP	Electromagnetic Transient Program Analysis
EPA	Environmental Protection Agency
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ER	Environmental Report
ESD	Electric Staff Division
f	Frequency
FA	Forced Air
FAA	Federal Aviation Administration
FCC	Federal Communications Commission
FDDI	Fiber Distributed Data Interface
FHWA	Federal Highway Administration
FM	Frequency Modulation
FOW	Front of Wave
FSK	Frequency Shift Keying
ft	Feet
Fv	Allowable Shear Stress
GFI	Ground Fault Interrupting
GFR	General Field Representative
GHz	Gigahertz (1,000,000,000 hertz or cycles per second)
GIS	Gas-Insulated Substations
gpm	Grams per minute
GPR	Ground Potential Rise
GRD	Ground
HMI	Human–Machine Interface
hr	Hour
HUD	Department of Housing and Urban Development
HV	High Voltage
HVAC	Heating, Ventilating, and Air Conditioning
Hz	Hertz (cycles per second)
I.D.	Inside Diameter
ICBO	International Conference of Building Officials
ICEA	Insulated Cable Engineers Association
IEC	International Electrotechnical Association
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers

IES	Illuminating Engineering Society
in.	Inch
IPS	International Pipe Standard
IR	Insulation Resistance
ISO	International Organization for Standardization
J	Joule
K	Rated Voltage Range Factor
kA	Kiloamperes (1,000 amperes)
kcmil	Kilocircular mils (1,000 circular mils)
kg	Kilogram (1,000 grams)
kHz	Kilohertz (1,000 hertz or cycles per second)
km	Kilometers (1,000 meters or 1,608 feet)
km/h	Kilometers per hour
kN	Kilonewtons
kNm	Kilonewton meters
kPa	Kilopascals (1,000 Pascals)
ksi	KIP (1000lbs) per square inch
kV	Kilovolt (1,000 volts)
kVA	Kilovolt-amperes (1,000 volt-amperes)
kVAR	Kilovolt-amperes reactive (1,000 volt-amperes reactive)
kWh	Kilowatt-hour
LAN	Local Area Network
lb	Pound
lbs	Pounds
lbs/ft	Pounds per foot
L/C	Inductance/Capacitance
LCD	Liquid Crystal Display
LPL	Lightning Protective Level
LRFD	Load and Resistance Factor Design
LTC	Load Tap Changer
LTU	Line Tuner Unit
LV	Low voltage
m	Meter(s)
m^2	Square meter
mA	Milliamperes (0.001 ampere)
MAS	Multiple Address System
Mbps	megabits per second (1,000,000 bits per second)
MCOV	Maximum Continuous Operating Voltage
McTRANS Center	Center for Microcomputers in Transportation
MHz	Megahertz (1,000,000 hertz or cycles per second)
mil	One Thousandth of an Inch
mm	Millimeter (0.001 meter)
MOV	Motor-Operated Valve
mph	Miles per hour
mV	Millivolt
MVA	Megavolt-amperes (1,000,000 volt-amperes)
MVAR	Megavolt-amperes reactive (1,000,000 volt-amperes)
MW	Megawatt (1,000,000 watts)
N	Newton
N/m	Newtons per meter

NACE	Formerly known as "National Association of Corrosion Engineers", now known as "NACE International – The Corrosion Society"
NEC	*National Electrical Code*
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act of 1969
NESC	*National Electrical Safety Code*
NETA	National Electrical Testing Association
NFPA	National Fire Protection Association
NI-CAD	Nickel Cadmium
NLTC	No-Load Tap Change
NRECA	National Rural Electric Cooperative Association
O & M	Operations and Maintenance
O.I.	Oxygen Index
OA	Self-cooled
OA/FA	Self-cooled and assisted by forced air for one stage
OA/FA/FA	Self-cooled and assisted by forced air for two stages
OA/FA/FOA	Self-cooled and assisted by forced air and forced oil
OA/FOA	Self-cooled and assisted by forced oil
OA/FOA/FOA	Self-cooled and assisted by forced air and forced oil for two stages
OC-1	SONET optical carrier 1 (51.83 Mbps)
OC-3	SONET optical carrier 3 (155.52 Mbps)
OC-12	SONET optical carrier 12 (622.08 Mbps)
OC-48	SONET optical carrier 48 (2488.32 Mbps)
O.D.	Outside Diameter
OEM	Original Equipment Manufacturer
OLF	Overload factor
OPGW	Optical Ground Wire
OSHA	Occupational Safety and Health Administration
OSI	Open Systems Interconnection
PC	Personal computer
PCA	Portland Cement Association
PCB	Polychlorinated biphenyls
pcf	Pounds per cubic foot
PCM	Pulse Code Modulation
PE	Polyethylene
PF	Power Factor
pH	Logarithmic measure of hydrogen ion concentration
PILC	Paper Insulated Lead Cable
PLC	Power line Carrier; Programmable Logic Controller
PO	Purchase Order
psf	Pounds per square foot
psi	Pounds per square inch
PT	Potential Transformer
PVC	Polyvinyl Chloride
Pw	Wind pressure
RAM	Random Access Memory
RCF	Ratio Correction Factor
REA	Rural Electrification Administration
RF	Rating Factor; Radio Frequency
rms	Root Mean Square

RPM	Revolutions per Minute
RQD	Rock Quality Designation
RTU	Remote Terminal Unit
RUS	Rural Utilities Service
Rw	Structure-type factor
S.O.	Sparkover
S.S.	Switching Surge
SBCC	Southern Building Code Congress
SCADA	Supervisory Control and Data Acquisition
SF_6	Sulfur Hexaflouride
SOE	Sequence of Events
SONET	Synchronous Optical Network
SPCC	Spill Prevention Control and Countermeasure
SPL	Arrester Surge Protective Level
SSB	Single Sideband
SSPC	Steel Structures Painting Council
Std.	Standard
Sym	Symmetrical
TCF	Transformer Correction Factor
TCP/IP	Transport Control Protocol/Internet Protocol
TDM	Time-Division Multiplexed
TFOW	Transformer Front of Wave
TIN	Triangulated Irregular Network
TNA	Transient Network Analysis
T.O.C.	Top Of Concrete
TOV	Temporary Overvoltage
UBC	Uniform Building Code
UCA	Utility Communications Architecture
UL	Underwriters Laboratories
USDA	United States Department of Agriculture
USWG	USA Steel Wire Gage
UTP	Unshielded Twisted Pair
V	Volts
VA	Volt-amperes
VAC	Volts Alternating Current
VAR	Volt-amperes reactive
VDC	Volts Direct Current
VSAT	Very Small Aperture Terminal
VSD	Variable-Speed Drive
VT	Voltage Transformer
WAN	Wide Area Network
XLPE	Cross-Linked Polyethylene
ZPA	Zero Period Acceleration

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CHAPTER 1
INTRODUCTION

1.1 PREFACE

This bulletin provides design guidance for the increasing numbers of substations necessary to meet the increasing electrical demands in areas served by Rural Utilities Service borrowers (here and after called cooperatives). This guide bulletin is intended for the benefit of cooperatives, their consulting and staff engineers, and others interested in rural substation design and construction concerns and considerations.

Substations should be designed, constructed, and operated to meet customers' needs at the lowest possible cost commensurate with the quality of service desired. The typical system may include substations for voltage transformation, sectionalizing, distribution, and metering a number of times between generation and utilization.

1.2 PURPOSE AND SCOPE

This bulletin covers rural transmission and distribution with air-insulated, outdoor substations 345 kV (phase-to-phase) and below.

Possible design responsibilities of the engineer are covered, including preparation of construction drawings, material, equipment and labor specifications, and any other engineering design services that may be required.

The engineering function is generally more than furnishing of design and specifications. Recognition of this function becomes especially important when a cooperative employs an engineering firm to supplement its staff. (See U.S. Code of Federal Regulations, Title 7, Part 1724 (7 CFR 1724), "Electric Engineering, Architectural Services and Design Policies and Procedures.") The contract between a cooperative and an engineering firm should be clear in its definition of the engineering functions to be performed. Within this bulletin, it should be understood that the term "engineer" could mean either a cooperative's staff engineer(s) or a consultant's engineer(s).

The engineer needs to use these guidelines together with experience and knowledge. A list of references at the end of most chapters will aid in the search for more detailed information. It is recommended that, where other resources are referenced, such as those of ANSI, IEEE, RUS, and ASTM, the substation designer obtain and become familiar with the appropriate document.

Use of this publication for substation design will usually result in an economical approach from a system standpoint. This should eventually result in the evolution of standard designs for a given system. Standardization is a desirable and achievable objective that should be pursued.

Technical advances and changes in codes and standards that could cause some of the material in this bulletin to become obsolete continue to proliferate in the electric power industry. Users, therefore, need to continue their own efforts to stay up to date with the changing technologies.

1.3 RELATIONSHIP OF SUBSTATION TO OVERALL POWER SYSTEM

A substation is part of a system and not an entity to itself. Normally, a power system is designed so that

the effects of an outage (caused by the failure of a single component such as a transformer, transmission line, or distribution line) will result in minimal interruption of service and affect the fewest customers possible.

Failure of one component in a system often forces a greater than normal load to be carried by other components of the system. Such contingencies are normally planned for and incorporated into design criteria.

When evaluating the switching arrangement for a substation, an engineer needs to be aware of the system configuration of which the substation will be a part. System contingency arrangements need to permit the outage of components in a substation for maintenance and unscheduled outages.

Most substations are designed to operate un-attended. Remote indication, control, metering, and methods of communication are often provided so that systems and portions of systems can be monitored from a central point.

An example of an outage consideration for a substation would include a transmission switching station that operates with a simple main bus. An outage of the bus results in a complete interruption of power through the substation. The engineer will need to consider other equipment in the substation, such as a transfer bus or different multi-bus arrangement. The engineer should also evaluate the adjacent system to determine if the load can be diverted around the substation for outages to minimize the equipment that is installed in a substation.

1.4 IMPORTANCE OF ADEQUATE SUBSTATION PLANNING AND ENGINEERING

(See Bulletins 1724D-101A, "Electric System Long-Range Planning Guide," and 1724D-101B, "System Planning Guide, Construction Work Plans.")

Substation planning considers the location, size, voltage, sources, loads, and ultimate function of a substation. If adequate planning is not followed, a substation may require unnecessary and costly modification.

The engineer's detailed work requires use of valid requirements and criteria, appropriate guidelines, and engineer's own expertise in order to provide construction drawings and associated documents appropriate for needed system improvements. The engineer's ability to meld the diverse constraints into an acceptable design is essential.

During the design phase, the engineer should avoid personal preferences in solving technical problems that diverge from the use of nationally accepted standards, Rural Utilities Service (RUS) standards, or the concept of the cooperative's standard designs.

Adequate engineering design provides direction for construction, procurement of material and equipment, and future maintenance requirements while taking into account environmental, safety, and reliability considerations.

1.5 TYPES OF SUBSTATIONS

1.5 .1 General

Substations may be categorized as distribution substations, transmission substations, switching substations, or any combination thereof.

One design tendency is to reduce costs by reducing the number of substations and taking advantage of economies of scale. Conversely, practical system design and reliability considerations tend to include many substations. One function of system studies is to balance these two viewpoints.

1.5.2 Distribution Substations

A distribution substation is a combination of switching, controlling, and voltage step-down equipment arranged to reduce subtransmission voltage to primary distribution voltage for residential, farm, commercial, and industrial loads.

Rural distribution substation capacities vary. Substations generally include one l.5 MVA to three 5 MVA transformers. These substations may be supplied radially, tapped from a subtransmission line, or may have two sources of supply. Most cooperatives' substations have 12,470Y/7200-volt or 24,490Y/14,400-volt distribution circuits.

A special class of distribution substation would include a dedicated customer substation. This substation would be similar to a distribution substation except that all of its capacity would be reserved for the service of one customer. The secondary voltages of a dedicated substation would also be modified to match special requirements of the customer. Coordination with the customer is of primary importance in determining the technical requirements. Confirmation of the technical terms being used is likely to be required since electrical engineers in differing industries may use the same terms to describe similar, yet technically different, criteria.

> A good example of confusion over the definition of terms that can be experienced exists for the term "outage." An industrial firm with a variable-speed drive (VSD) required a minimum number of outages on the incoming feeder since any outage resulted in the drive's going down, several hours' delay in the restart, and possible environmental consequences during the outage. The utility reviewed its own outage criteria and determined it met the customer's requirements. After installation, the customer complained about the large number outages forcing the VSD motor to de-energize. Further discussion revealed the customer's definition of outage was any voltage drop of 20 percent or more for more than three cycles. The utility's definition of outage was any discontinuance of service after all reclosing of a feeder failed. Differing usage of common terms resulted in unacceptable service to the customer, requiring modifications to the installation.

1.5.3 Transmission Substations

A transmission substation is a combination of switching, controlling, and voltage step-down equipment arranged to reduce transmission voltage to subtransmission voltage for distribution of electrical energy to distribution substations. Transmission substations frequently have two or more large transformers.

Transmission substations function as bulk power distribution centers, and their importance in the system often justifies bus and switching arrangements that are much more elaborate than distribution substations.

1.5.4 Switching Substations

A switching substation is a combination of switching and controlling equipment arranged to provide circuit protection and system switching flexibility.

Switching stations are becoming common on cooperatives' transmission systems. Flexible switching arrangements in a transmission network can aid in maintaining reliable service under certain abnormal or maintenance conditions.

1.6 REFERENCES

7 CFR 1724, "Electric Engineering, Architectural Services and Design Policies and Procedures."

RUS Bulletin 1724D-101A, "Electric System Long-Range Planning Guide."

RUS Bulletin 1724D-101B, "System Planning Guide, Construction Work Plans."

CHAPTER 2
GENERAL DESIGN CONSIDERATIONS

2.1 INITIAL AND ULTIMATE REQUIREMENTS

Cooperatives should consider both short- and long-range plans in the development of their systems. Timely development of plans is not only essential for the physical and financial integrity of electrical systems, it is also essential in supplying customers with adequate service.

The long-range plan identifies the requirements of a substation not only for its initial use but also for some years in the future. Consider ultimate requirements during the initial design. Make economic comparisons to discover what provisions are necessary for ease of addition.

> Significant considerations for future construction are the outage requirements when equipment is added. These requirements should be considered with the utility's ability to serve the load during any outage.

Remember that development plans embrace philosophies of equipment and system operation and protection before construction is started. Changes in the cooperative's standard design philosophies should be reviewed by the personnel who design, operate, and maintain the proposed equipment. Departures from standard designs could jeopardize the operation of the system.

Use the Substation Design Summary in Appendix B to Chapter 3 to summarize basic design data.

2.2 SITE CONSIDERATIONS

Two of the most critical factors in the design of a substation are its location and siting. Failure to carefully consider these factors can result in excessive investment in the number of substations and associated transmission and distribution facilities.

It is becoming increasingly important to perform initial site investigations prior to the procurement of property. Previous uses of a property might render it very costly to use as a substation site.

Such previous uses might include its use as a dumping ground where buried materials or toxic waste has to be removed prior to any grading or installation of foundations.

The following factors should be evaluated when selecting a substation site:

    a. Location of present and future load center
    b. Location of existing and future sources of power
    c. Availability of suitable right-of-way and access to site by overhead or underground transmission and distribution circuits
    d. Alternative land use considerations
    e. Location of existing distribution lines
    f. Nearness to all-weather highway and railroad siding, accessibility to heavy equipment under all weather conditions, and access roads into the site
    g. Possible objections regarding appearance, noise, or electrical effects
    h. Site maintenance requirements including equipment repair, watering, mowing, landscaping, storage, and painting
    i. Possible objections regarding present and future impact on other private or public facilities

j. Soil resistivity
k. Drainage and soil conditions
l. Cost of earth removal, earth addition, and earthmoving
m. Atmospheric conditions: salt and industrial contamination
n. Cost of cleanup for contaminated soils or buried materials
o. Space for future as well as present use
p. Land title limitations, zoning, and ordinance restrictions
q. General topographical features of site and immediately contiguous area; avoidance of earthquake fault lines, floodplains, wetlands, and prime or unique farmlands where possible
r. Public safety
s. Public concern; avoidance of schools, daycare centers, and playgrounds
t. Security from theft, vandalism, damage, sabotage, and vagaries of weather
u. Total cost including transmission and distribution lines with due consideration of environmental factors
v. Threatened and endangered species and their critical habitat
w. Cultural resources
x. Possible adverse effects on neighboring communications facilities

Choose a substation location that precludes placing any communications facilities within the substation 300 V peak ground potential rise (GPR) zone of influence. See ANSI/IEEE Std. 367-1987, "Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault," and ANSI/IEEE Std. 487-1992, "Communication Facilities Serving Electric Power Stations, Guide for the Protection of Wire Lines."

2.3 ENVIRONMENTAL CONSIDERATIONS

2.3.1 General

2.3.1.1 RUS Environmental Policies and Procedures, 7 CFR 1794: This Regulation specifies RUS environmental requirements pursuant to the implementation of the National Environmental Policy Act of 1969 and Council on Environmental Quality Regulations. It also references additional authorities, directives, and instructions relevant to protection of the environment.

As a general rule, substations requiring greater than 2 hectares (5 acres) of new physical disturbance need an Environmental Assessment (EA), while those below generally require an Environmental Report (ER) (see RUS Bulletins 1794A-600, "Guide for Preparing an Environmental Report for Categorically Excluded Projects" and 1794-601, "Guide for Preparing an Environmental Report for Electric Projects Requiring an Environmental Assessment").

2.3.1.2 Appearance: Appearance is becoming increasingly important to the public. In some areas, zoning regulations and suggestions by civic organizations often mean screening, low-profile designs, or other measures to improve appearance. The absence of such direct influence in rural areas should not be a reason for not considering newer design practices. The general trend is to locate substations in a way that they are not strikingly visible to the public. A substation set back from a heavily traveled road may require little or no architectural treatment to be acceptable.

Coordinate engineering of transmission, distribution, and substation facilities to develop the least overall objectionable layout. Consider underground distribution circuit exits for special applications.

The silhouette of a substation may be reduced in several ways, including the use of solid-shape structural sections. Lowering of the substation profile may also be accomplished by means other than underground circuits although this approach may necessitate a larger surface area, resulting in larger site requirements. Lower profile designs for substation high-voltage equipment may be cost-effective in design and in reducing the profile that the substation projects.

Landscaping or architectural screening may offer effective means to blend a substation into the surrounding environment. Landscaping has typically included the use of trees, bushes, and the like to screen the substation. In some cases, masonry walls or enclosures have been necessary to meet permitting requirements in special use areas. Some sites may provide a natural screening with either vegetation or natural barriers.

Generally, it is better to use complementary rather than contrasting colors. Sometimes, coloring can be used to blend substation equipment into the background.

Outdoor lighting of the substation site may have an effect on the acceptance of the substation in a community. Lighting is typically a means to deter vandalism. It also provides safety for line crews who may be performing maintenance at night. A means of switching off a portion of the lights at night to provide reduced lighting may make the site more acceptable to the community.

2.3.1.3 Public Safety: Substations should be safe for people who may have occasion to be near them.

The primary means of ensuring public safety at substations is by the erection of a suitable barrier such as a metal fence. Unless local restrictions are more conservative, the fence needs to meet the minimum requirements specified in the *National Electrical Safety Code* and IEEE Std. 1119, "IEEE Guide for Fence Safety Clearances." (RUS recommends 8 feet for the fence height: 7 feet of fabric and a 1-foot extension of barbed wire.) Metal fences have to be properly grounded; grounding of fences is covered in Chapter 9. Material and specification of fences is covered in Chapter 6, Section 6.9.

Additional means of protecting the public are provided through adequate design of all facilities inside the fence and the addition of a peripheral ground outside the fence. Protection that alleviates possible potential differences is discussed in Chapter 9.

Appropriate warning signs should be posted on the substation's peripheral barrier fence. The engineer should specify their location and design. Substations, no matter how small, should have one sign per side, as a minimum. For each substation site, assess whether standard signs are sufficient. Special bilingual signs may be advisable for some areas. Additional signs, such as "No Trespassing," may be advisable in some areas. See ANSI Std. Z535.2, "Environmental and Facility Safety Signs," for further information.

2.3.1.4 Audible Noise: Sources of audible noise within a substation include transformers, voltage regulators, circuit breakers, and other intermittent noise generators. Among the sources, transformers have the greatest potential for producing objectionable noise. The design engineer should consider audible noise reference documents and regulations.

Corona, which is localized incomplete dielectric failure, causes a hissing sound. Corona noise occurring at voltages of 230 kV and below is seldom serious. Corona noise is usually kept to a tolerable level if guidelines for minimizing electrical effects are followed. Design for 345 kV systems will normally require extra-high-voltage (EHV) connectors and fittings or corona shields to reduce the amount of noise from corona to tolerable levels.

The U.S. Environmental Protection Agency (EPA) has published "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety" (Report Number 550/9-74-004), and "Public Health and Welfare Criteria for Noise" (Report Number 550/9-73-002). Several state and local noise ordinances limit noise at the property line. Table 2-1 lists guidelines for considering noise in land-use planning and control. The reaction to noise can be subjective, so each substation situation should be analyzed separately.

Table 2-1: Noise-Zone Classification.
Ref. Federal Interagency Committee on Urban Noise, 1980, p. 5.

Noise Descriptor					
Noise Zone	Noise Exposure Class	DNL Day-Night Average Sound Level	Leq (hour) Equivalent Sound level	NEF Noise Exposure Forecast	HUD Noise Standards
A	Minimal Exposure	Not Exceeding 55	Not Exceeding 55	Not Exceeding 20	Acceptable
B	Moderate Exposure	Above 55[a] But Not Exceeding 65	Above 55 But Not Exceeding 65	Above 25 But Not Exceeding 30	Acceptable
C-1	Significant Exposure	Above 65 But Not Exceeding 70	Above 65 But Not Exceeding 70	Above 30 But Not Exceeding 35	Normally Unacceptable
C-2	Significant Exposure	Above 70 But Not Exceeding 75	Above 70 But Not Exceeding 75	Above 35 But Not Exceeding 40	Normally Unacceptable
D-1	Severe Exposure	Above 75 But Not Exceeding 80	Above 75 But Not Exceeding 80	Not Exceeding 45	Unacceptable
D-2	Severe Exposure	Above 80 But Not Exceeding 85	Above 80 But Not Exceeding 85	Above 45 But Not Exceeding 50	Unacceptable
D-3		Above 85	Above 85	Above 50	Unacceptable

[a] HUD, DOT, and EPA recognize Ldn = 55 dB as a goal for outdoor sites in residential areas in protecting the public health and welfare with an adequate margin of safety.
However, it is not a regulatory goal. It is a level defined by a negotiated scientific consensus without concern for economic and technological feasibility or the needs and desires of any particular community.

See Chapter 5, Section 5.2.12, for more information.

2.3.1.4.1 Site Selection: If the substation has to be located in or near a residential area, select a site with the greatest distance from nearby residences, and, if possible, avoid a direct line of sight with them.

A site with natural barriers such as earth mounds or shrubbery is desirable since such barriers can help reduce the psychological impact of a new installation.

2.3.1.4.2 Layout Design: Good practice for noise control is to locate transformers the maximum possible distance from the substation fence. Once a transformer is located, its noise level at any distance can be estimated by using standard formula s. See IEEE Std. 1127, "IEEE Guide for the Design, Construction, and Operation of Electric Power Substations for Community Acceptance and Environmental Compatibility," for formulas that may be used. If noise is anticipated to be a problem, reduced sound levels are available from the transformer manufacturer or the equipment layout should be arranged to permit the installation of a sound barrier. Anticipated future requirements should also be considered since additional transformers will increase the noise level.

2.3.1.4.3 Level: As a general rule, substation noise will not be a problem if, when combined with ambient noise, it is less than 5 dBA above the ambient noise level. It may be desirable to measure the ambient noise levels at locations of concern. Measurements should be taken during the quietest periods, approximately midnight to 4 a.m. Calculation of the resultant sound level will then indicate whether further study is required. The references at the end of this chapter suggest methods to rigorously address noise problems.

2.3.1.4.4 Transformers: Chapter 5, Section 5.2, "Power Transformers" provides additional guidelines.

2.3.1.5 Electrostatic and Electromagnetic Effects: Consideration should be given to preventing radio and television interference that could result from visible corona. Significant corona could be caused by energized parts having small radii or from small-diameter conductors, particularly when conductive climatic conditions prevail. Experience has shown, though, that conductor fittings and energized parts other than conductors do not produce serious corona at phase-to-phase voltages of 230 kV and below. At 345 kV, electrical voltage gradients are such that corona shields and connectors designed to mitigate corona should be used.

It is necessary, however, to consider the size of conductors. Chapter 4, "Physical Layout," provides guidelines for fault and load-carrying conductors. Connections to equipment such as voltage transformers and coupling capacitors should not be sized from a current-carrying standpoint only. From a corona standpoint, conductors should not be smaller than 3/0 at 230 kV or 1/0 at 161 kV and 138 kV. At 345 kV, equipment jumpers should consist of bundled conductors.

2.3.1.6 Effluent: 40 CFR 110 and 112 provide regulations to eliminate the pollution of navigable waterways. The essence of these regulations is that, upon the failure of a container filled with a pollutant, such as oil in a transformer or oil circuit breaker, no harmful quantity of such pollutant (oil) may be allowed to enter a navigable waterway. Absolute prevention and containment of oil spills is not required by the regulations; however, the discharge of harmful quantities of pollutants into navigable waterways is prohibited. The regulations and interpretations thereof are dynamic. It is necessary to have a Spill Prevention Control and Countermeasures (SPCC) plan of action for disposing of effluent, should spills or leaks occur. Some oil pollution prevention measures are described in Chapter 8 and in RUS Bulletin 1724E-302, "Design Guide for Oil Spill Prevention and Control at Substations." If more than 5.0 acres of land will be disturbed during construction, a stormwater discharge permit has to be obtained from the appropriate state agency prior to the start of construction. See the above-mentioned CFR regulations and IEEE Std. 980, "IEEE Guide for Containment and Control of Oil Spills in Substations," for assistance in determining the appropriateness of in-place structures and items to be included in an SPCC plan.

The use of polychlorinated biphenyls (PCBs) as an insulation medium in liquid-filled transformers and capacitors has been discontinued. This type of impregnant has been phased out, because of its resistance to biodegradation, in favor of materials potentially less harmful to the environment.

2.3.2 Weather

2.3.2.1 General: As dependence on the use of electricity grows, it is increasingly important that substations operate more reliably in extremes of weather than in the past.

2.3.2.2 Temperature: It is necessary to design a substation for the extreme temperatures expected. Extreme temperatures could affect circuit breakers, relay protection, or the bus.

2.3.2.3 Wind: As a minimum, substations should be resistant to wind velocities as shown in Figure 2-1. Chapter 4, "Physical Layout," and Chapter 7, "Structures," provide specific guidelines on design. Local conditions may dictate more stringent wind designs.

2.3.2.4 Ice: A substation should continue to operate despite ice accumulation. Generally, consensus equipment standards specify ice loadings for both electrical and mechanical withstands. The complete substation assembly should also be undamaged by ice accumulation. From the ice accumulation history for a given substation's location, the engineer can judge whether more severe loadings than consensus equipment standards are necessary. Additional viewpoints on ice loading are provided in Chapter 4, "Physical Layout," and Chapter 7, "Structures."

2.3.2.5 Rain: A substation should be designed to be operable under predictable conditions of rainfall. Additionally, it is desirable that substation drainage be sufficient enough to exhibit little standing water within a few hours after a heavy rainfall. See Chapter 6, "Site Design," for guidelines.

2.3.2.6 Snow: Snow introduces an extremely variable hazard to substations because of uncertainties in drifting and accumulation. The substation has to be impervious to snow damage, and consideration needs to be given to snow accumulation and the maintenance of clearances. The engineer should seek local data on this weather variable.

2.3.2.7 Electrical Storms: The two measures normally employed for substation lightning protection are surge arresters and shielding. Application guidelines for surge arresters are included in Chapters 4 and 5. Surge arresters provide little protection against direct strokes. Shielding is provided by overhead wires, masts that are extensions of structures, or independent masts as covered in Chapter 4. A combination of surge arresters and shielding will reduce the probability of damage from lightning.

2.3.2.8 Humidity: Consideration should be given to installation of differential thermostat-controlled heating in outdoor cabinets such as circuit breaker control cabinets where condensation could be a problem. In areas where fog occurs often, and particularly where airborne contamination exists, frequent insulator flashovers may occur. Methods of reducing flashovers include the application of special insulation and insulator cleaning.

2.3.3 Altitude

Equipment that depends on air for its insulating and cooling medium will have a higher temperature rise and a lower dielectric strength when operated at higher altitudes; see ANSI Std. C37.30, "Standard Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports."

Surge arresters are designed for satisfactory operation at elevations up to a limit specified by the manufacturer. Applications above this limit are considered special, and the manufacturer should be consulted for a recommendation.

Dielectric strength of air, current ratings of conductors operated in air, and ambient temperatures should be corrected for altitude variation and be multiplied by the factors shown in Columns "A" and "B" of Table 2-2.

Table 2-2: Altitude Correction Factors for Substation Equipment.
Ref. ANSI/IEEE Std. C37.30-1992, Table 1, Copyright © 1992. IEEE. All Rights Reserved.

Altitude		Altitude Correction Factor to Be Applied to:		
		A	B	C
Feet	Meters	Dielectric Strength	Current Rating	Ambient Temperatures
3300	1000	1.00	1.00	1.00
4000	1200	0.98	0.995	0.992
5000	1500	0.95	0.99	0.980
6000	1800	0.92	0.985	0.968
7000	2100	0.89	0.98	0.956
8000	2400	0.86	0.97	0.944
9000	2700	0.83	0.965	0.932
10000	3000	0.80	0.96	0.920
12000	3600	0.75	0.95	0.896
14000	4200	0.70	0.935	0.872

2.3.4 Earthquakes

Substations subjected to intense earthquakes will most likely be damaged; however, seismic design practices can minimize the damage. Although some substation equipment is inherently shock resistant, the foundations, structures, equipment anchors, insulation, and conductors may not be. Designs that minimize damage should be utilized in high seismic areas. Consideration should be given not only to replacement costs but also to lead times for delivery of replacement equipment.

IEEE Std. C57.114, "IEEE Seismic Guide for Power Transformers and Reactors," provides recommendations as to design considerations for the installation of transformers and reactors when seismic activity is likely.

When substations will be constructed with Federal financing assistance, RUS require substation control buildings to meet the seismic provisions found in 7 CFR 1792, Subpart C.

Seismic loads are governed by the region of the country in which they occur. Figure 2-2 identifies the susceptibility of different areas of the country, with the higher numbered areas being more susceptible. Further discussion concerning seismic loads is explained in section 7.4.7 of this bulletin.

85(38)

90(40)

Alaska Note:
For coastal areas and islands,
use nearest contour.

120(54)
110(49)
100(45)
90(40)

130(58)

90(40)

90(40)

140(63)

130(58)

90(40)
100(45)
110(49)

140(63)
130(58)
120(54)

100(45)

110(49)

130(58)

120(54)

130(58)

130(58)
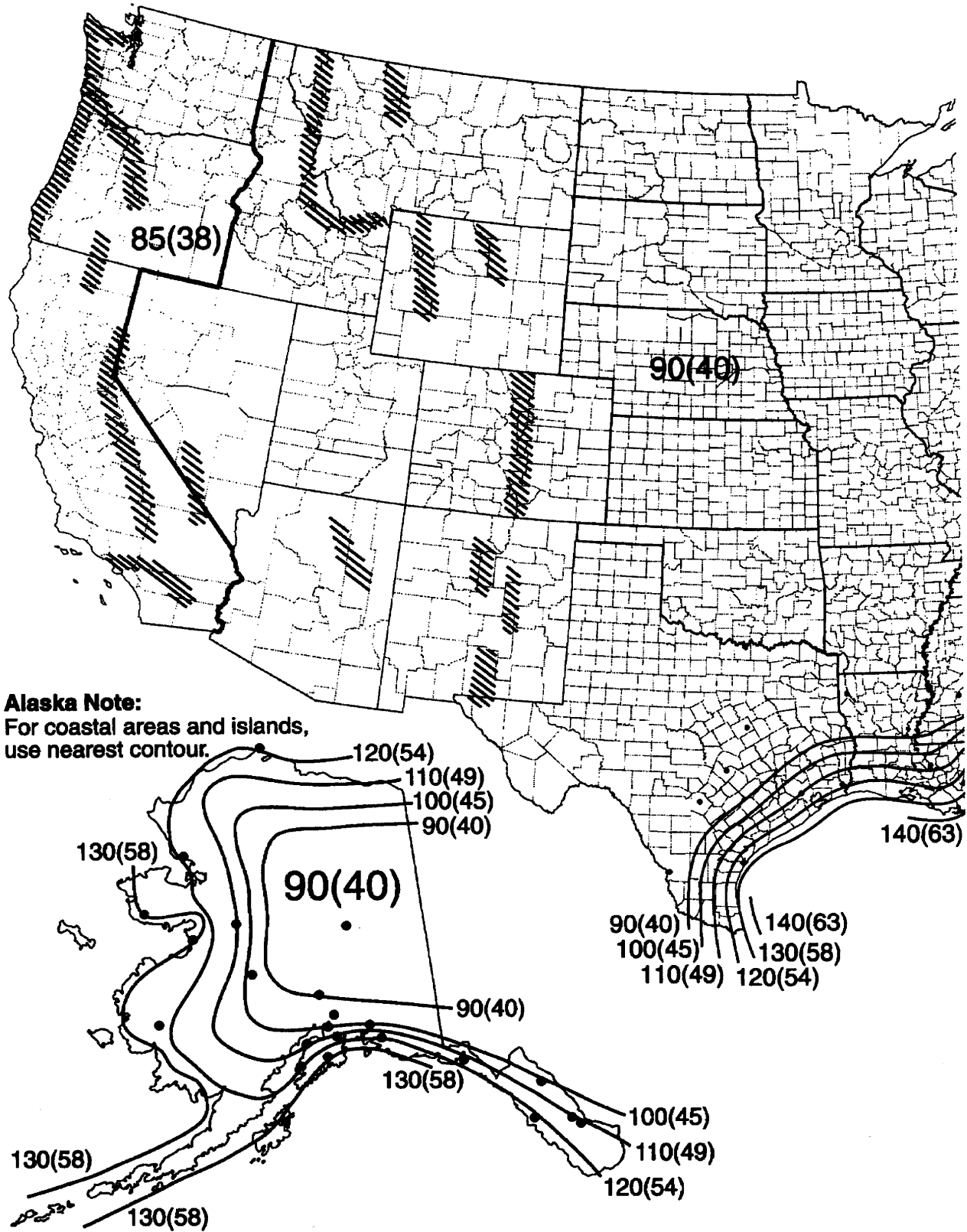
Figure 2-1: Basic Wind Speed. Ref. ANSI/ASCE Std. 7-95, Figure 6-1.
Reproduced with permission of the American Society of Civil Engineers, copyright © 1989.

90(40)
100(45)
110(49)
120(54)
130(58)

130(58)

140(63)

| ▨ | Special Wind Region |
| • | Population Center |

140(63)

150(67)

140(63)

Location	V mph	(m/s)
Hawaii	105	(47)
Puerto Rico	125	(56)
Guam	170	(76)
Virgin Islands	125	(56)
American Samoa	125	(56)

140(63)

150(67)
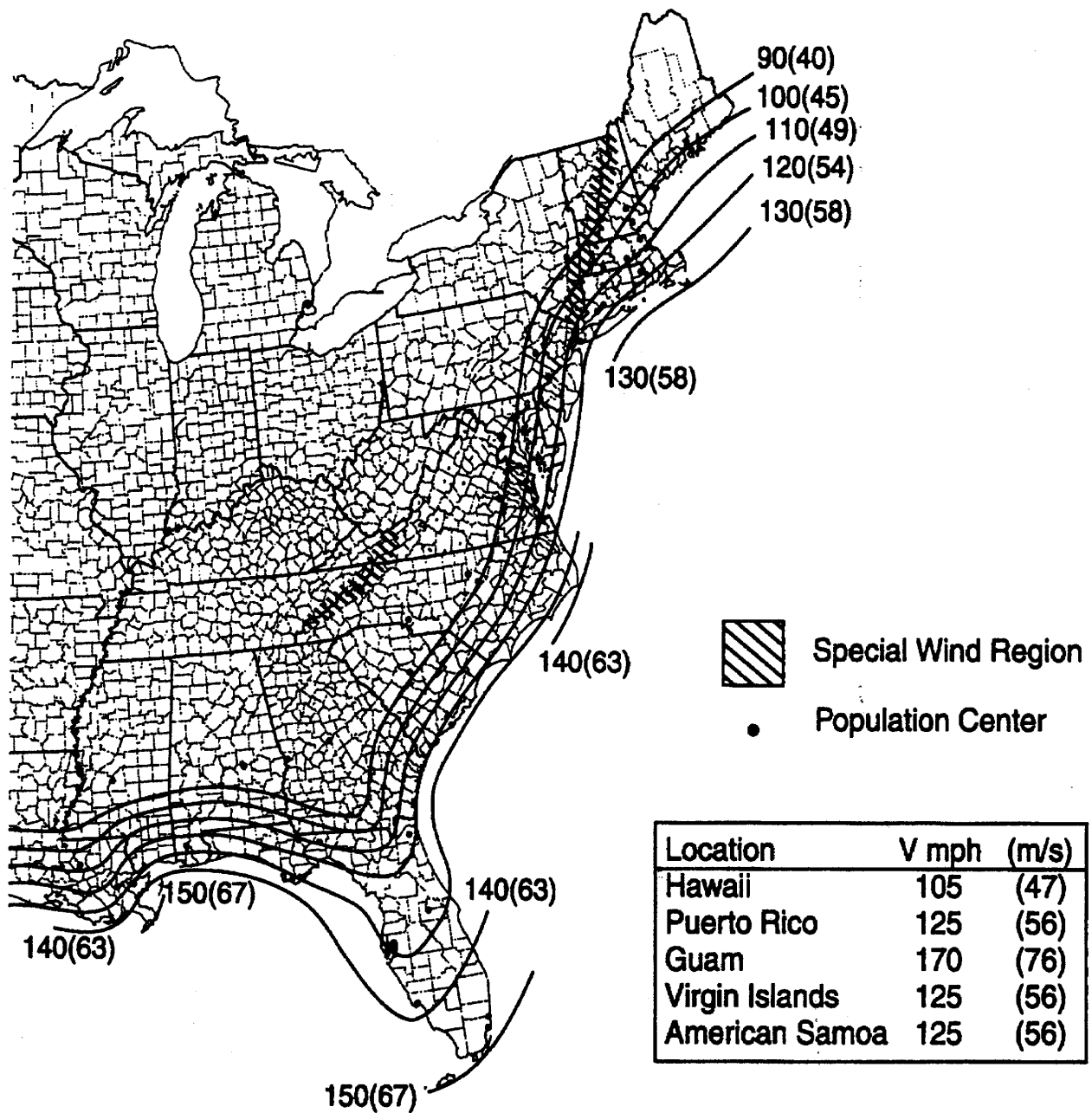
Notes:
1. Values are 3-second gust speeds in miles per hour (m/s) at 33 ft (10m) above ground for Exposure C category and are associated with an annual probability of 0.02.
2. Linear interpolation between wind speed contours is permitted.
3. Islands and coastal areas shall use wind speed contour of coastal area.
4. Mountainous terrain, gorges, ocean promontories, and special wind regions shall be examined for unusual wind conditions.

The seismic zone map from the *Uniform Building Code* has been included for reference. See Figure 2-2.
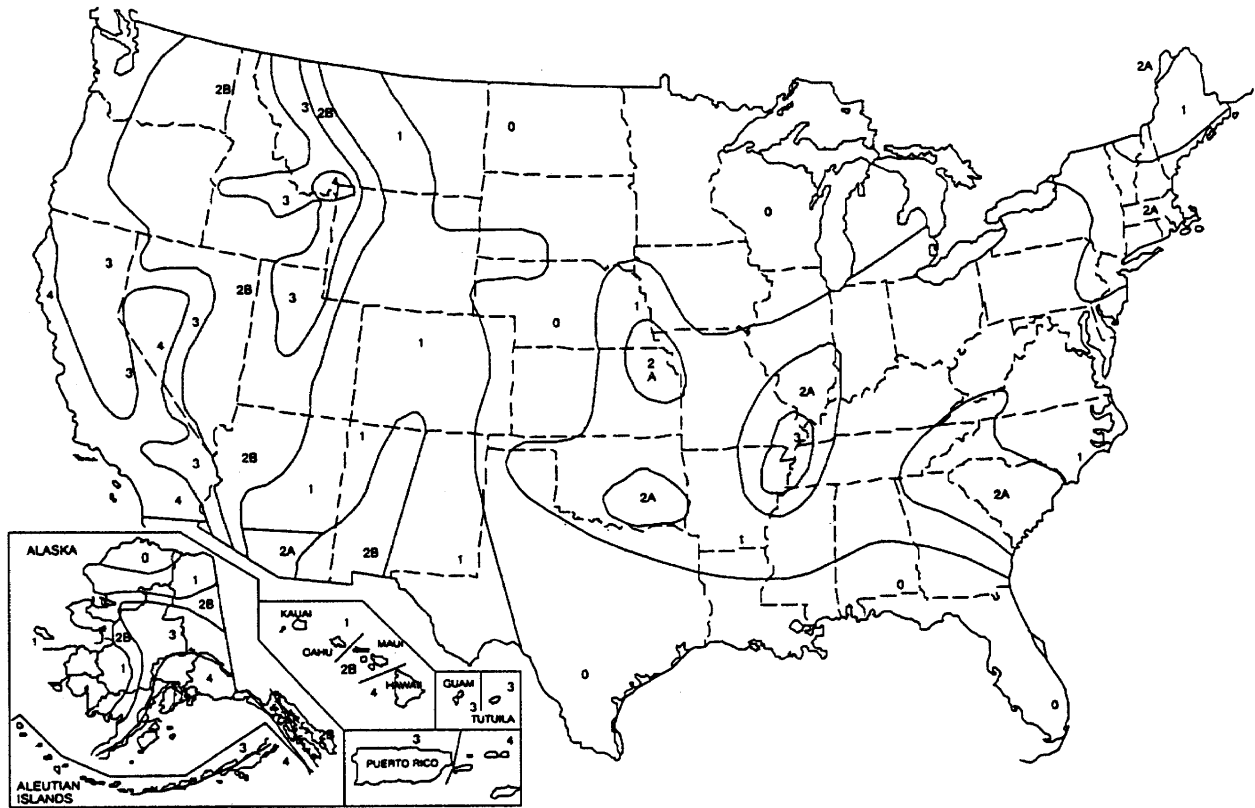
Figure 2-2: Seismic Zone Map of the United States. Ref. Uniform Building Code—1997, Figure 16-2. Reproduced from the 1997 edition of the *Uniform Building Code*™, copyright © 1997, with permission of the publisher, the International Conference of Building Officials.

2.3.5   Other Considerations

2.3.5.1 Wildlife and Livestock: A substation should be protected from wildlife and livestock. The primary means of protection is the perimeter barrier. This is generally a chain link fence that keeps out larger animals. It may also be necessary to have rodent and/or reptile barriers. It is recommended that all substation materials be non-nutrients, since impregnable barriers would be too difficult to attain. Insect screening should be applied where local experience indicates it is beneficial Avoiding attractive nesting and perching sites usually minimizes bird damage. Adequate clearances should be provided to prevent electrocution of local bird species. For measures to prevent and mitigate damage from animals, insects, birds, and reptiles, see the Cooperative Research Network's (CRN's) manual on *Animal-Caused Outages*.

2.3.5.2 Airborne Foreign Material: Airborne seeds, leaves, debris, dust, and salts that are local phenomena could be a problem. Buildup could occur that would compromise electrical insulation or interfere with cooling. Appropriate prevention measures should be included in the design of a substation expected to be exposed to such contamination.

2.4 INTERFACING CONSIDERATIONS

Substations interface with roadways, area drainage, communications systems, and electric power lines. Sufficient lead time has to be allowed to coordinate activities with public agencies for roadway access and with communications agencies for communications facilities. Chapter 17 provides details on communications considerations.

When locating a new substation, coordinate the location, design, and construction with other utilities operating in the area. Other utility concerns include but are not limited to:

1. Telecommunications
2. Cable television
3. Water and sewer
4. Gas
5. Radio and television stations

There should be little difficulty ensuring proper substation interfacing with distribution, subtransmission, and transmission lines. Timely plans should be made so there is mutual agreement between the substation engineer and the various line engineers on the following:

1. Connecting hardware procurement responsibility
2. Mating of hardware to line support structure
3. Line identifications and electrical connections to suit planning engineering requirements
4. Substation orientation and line approach
5. Phase conductor and shield wire identification
6. Pull-off elevations, spacings, tensions, and angles

2.4.1 Line Tension

Confusion sometimes occurs in the matter of specifying line tensions in substations. In some cases, line tensions on the line side of a line approach or deadend structure will be much greater than on the line support structure in the substation. The substation engineer should specify the tension that will result in the maximum load on the substation line support structure with the wire under the most severe combination of temperature, wind, and ice loading. The condition at which maximum tension occurs has to be known in order to select appropriate overload factors. Chapter 7, "Structures," covers overload factor selection.

As a general rule, takeoff tensions should not exceed 8900 newtons (2000 pounds) per conductor for small distribution substations. However, the incoming transmission line alignment, wire size, and elevation differences can increase the required tensions.

2.5 RELIABILITY CONSIDERATIONS

A prime objective in the operation of an electric power system is to provide reliable service within acceptable voltage limits. Information on reliability may be found in ANSI Std. C84.1-1995, "Electric Power Systems and Equipment-Voltage Rating (60 Hz)." Cooperatives that design substations to operate within the voltage levels specified in this ANSI Standard should have reasonably reliable substations.

2.6 OPERATING CONSIDERATIONS

For simplicity and ease of maintenance, substation equipment arrangements, electrical connections, signs, and nameplates should be as clear and concise as possible. Information on safety signs can be found in ANSI Std. Z535.2, "Environmental and Facility Safety Signs."

A substation may occasionally experience emergency operating conditions requiring equipment to perform under abnormal situations. Depending on the length of time, the provision of unusual current-carrying capacity of some equipment or connections should always be considered and appropriately accounted for in the design.

2.7 SAFETY CONSIDERATIONS

It is paramount that substations be safe for the general public and for operating and maintenance personnel. Practical approaches include the employment and training of qualified personnel, appropriate working rules and procedures, proper design, and correct construction. The safeguarding of equipment also needs to be considered in substation design.

Personnel working standards are prescribed by regulations issued by the Occupational Safety and Health Administration (OSHA). These regulations are included in 29 CFR 1910 for general industry and 29 CFR 1926 for construction. In addition, various states may have standards the same as or stricter than those of OSHA. The engineer is expected to follow the regulations appropriate to the jurisdiction in which a substation is built.

It should be recognized that this bulletin presents substation design guidance information only and not detailed regulatory provisions, especially related to safety. The engineer is responsible for researching and ensuring substations are designed in compliance with the applicable requirements of RUS, the *National Electrical Safety Code*, *National Electrical Code*, OSHA, and local regulations. The engineer is also responsible for analyzing expected local conditions, and, where warranted, including provisions in substation designs beyond the minimum provisions for safety established in the various regulatory codes.

2.8 MAINTENANCE CONSIDERATIONS

Substation design needs to allow maintenance to be accomplished with a minimum impact on a substation's operation. Allocation of adequate working space is necessary.

In selecting equipment, consider the service intervals recommended by the manufacturers and past experience in using a particular manufacturer's equipment.

See Chapter 20, "Maintenance," for more information.

2.9 REFERENCES

7 CFR 1792, subpart C, "Seismic Safety of Federally Assisted New Building Construction"

7 CFR 1794, "Environmental Policies and Procedures."

40 CFR 110, "Discharge of Oil."

40 CFR 112, "Oil Pollution Prevention."

ANSI Std. C84.1, "Electric Power Systems and Equipment-Voltage Rating (60 Hz)."

ANSI Std. Z535.2, "Environmental and Facility Safety Signs."

ANSI/ASCE Std. 7-95, "Minimum Design Loads for Buildings and Other Structures."

ANSI/IEEE Std. C2, *National Electrical Safety Code*.

ANSI/IEEE Std. C37.30, "Standard Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports."

ANSI/IEEE Std. 367, "Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault."

ANSI/IEEE Std. 487, "Communication Facilities Serving Electric Power Stations, Guide for the Protection of Wire Line."

Bragdon, C.R., "Municipal Noise Ordinances: 1975," *Sound and Vibration* 9(12): 24-30 (December 1975).

Federal Interagency Committee on Urban Noise, 1980, p. 5.

Fink and Carroll, *Standard Handbook for Electrical Engineers*. Section 11-100. 10th ed. New York: McGraw-Hill, 1968.

IEEE Std. C57.114, "IEEE Seismic Guide for Power Transformers and Reactors."

IEEE Std. 980, "IEEE Guide for Containment and Control of Oil Spills in Substations."

IEEE Std. 1119, "IEEE Guide for Fence Safety Clearances."

IEEE Std. 1127, "IEEE Guide for the Design, Construction, and Operation of Safe and Reliable Substations for Community Acceptance and Environmental Compatibility."

International Conference of Building Officials (ICBO), *Uniform Building Code—1997*.

Lawless, E.B., "Noise Control Regulations and Effects Upon Substation Design, Annual Conference of Engineering and Operation Division," Southeastern Electric Exchange, New Orleans, Louisiana, April 26-27, 1976.

National Rural Electric Cooperative Association, Cooperative Research Network, *Animal-Caused Outages*. Project 94-5. Arlington, Va.: NRECA, 1996.

Occupational Safety and Health Administration (OSHA) Documents; 29 Code of Federal Regulations Part 1910, General Industry, and Part 1926, Construction.

Pedersen, R.S., "Audible Noise Reduction in New and Existing Substations," Engineering, and Operating Conference, Pacific Coast Electrical Association, San Francisco, California, March 18-19, 1976.

RUS Bulletin 1724E-302, "Design Guide for Oil Spill Prevention and Control at Substations."

RUS Bulletin 1794A-600, "Guide for Preparing an Environmental Report for Categorically Excluded Projects."

RUS Bulletin 1794-601, "Guide for Preparing an Environmental Report for Electric Projects Requiring an Environmental Assessment"

Schulz, M.W., "Transformer Audible Noise," IEEE Power Engineering Society Summer Meeting, Portland, Oregon, July 17-23, 1976.

U.S. Environmental Protection Agency, "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare with an Adequate Margin of Safety," Report No. 550/19-74-004, Washington, D.C., March, 1974.

U.S. Environmental Protection Agency, "Public Health and Welfare Criteria for Noise," Report No. 550/9-73-002, Washington, D.C., July 27, 1973.

CHAPTER 3
DOCUMENTS

3.1 GENERAL

The primary function of a substation design engineer is to produce or supervise the development of formal plans from which a substation can be constructed.

Section 3.1.1 lists documents or studies that may also be required as part of the engineer's responsibility. The timing and chronological order of the documents may vary, depending on the particular substation's requirements.

3.1.1 Possible Documents or Studies Required of the Engineer

1. Site Comparison and Suitability Evaluation
2. Environmental Assessment (EA) or Environmental Report (ER)
3. Substation Design Summary Form
4. Functional One-Line Diagram
5. Application for Zoning Variance or Change
6. Specifications for Equipment
7. Request for Proposals to Furnish Equipment
8. Evaluation of Proposals to Furnish Equipment
9. Construction Plan Drawings
10. Backup Sketches and Calculations for Construction Plans
11. Substation Drawings (Detailed One-Line, Elementary, and Schematic Diagrams)
12. Requisitions for Material and Equipment
13. Application for Building Permit
14. Application for Permits for Roadway and Drainage Interface
15. Application for FCC License
16. Construction Specifications
17. Inquiry for Proposals to Furnish Construction
18. Evaluation of Contractor's Proposals
19. Comment Letters on Equipment Vendors' Submittals
20. Calculations for Selection of Protective Relaying and Devices
21. Economic Comparisons

Formal documentation should be clearly presented. Since the electric utility industry uses English units for specifying substation design construction and materials, documentation may be completed using English units of measure. Metric equivalent units may also be included in parentheses, e.g., 8.0 feet (2.45 meters). During the formulation of design, some sketching and calculations are required to arrive at optimum designs. While these are not a part of the formal plans, they are nevertheless useful in planning and are often valuable for future reference.

3.2 NEED FOR DOCUMENTATION

Documentation forms the basis for the expression and evaluation of engineering concepts. A document serves as a vehicle for the cooperative and engineer to reach agreement on a particular subject. In its final form, a document fulfills its primary role of establishing design and functional requirements. A document

also serves as a record of what was built, specified, or evaluated. The importance of good records in substation design deserves emphasis. Successful designs and accurate records are convenient references for designs and for standardized approaches for new substations. Records can also be very useful in diagnosing and correcting problems. Appendix B to this chapter is a Substation Design Summary where design information can be recorded for future reference.

3.3 PROCEDURES

RUS has required substation design procedures and, in addition, each cooperative may have certain procedures that suit its needs.

The chronology of a substation design is generally as shown in Table 3-1 with elapsed times varying according to a particular project's requirements. See 7 CFR 1726.22, "Methods of Construction," and 7 CFR 1724.53, "Preparation of Plans and Specifications."

Table 3-1: Substation Design Chronology

1. Identification of substation needs from Load Forecast (formerly Power Requirements Study) and cooperative's long-range plan
2. Pre-loan engineering
3. Application for loan; see 7 CFR 1710.119, "Loan Processing Priorities"
4. Loan approval
5. Final procurement of real estate
6. Selection of major equipment
7. Preparation of plans and specifications; see 7 CFR 1724.53, "Preparation of Plans and Specifications"
8. RUS Form 764, "Substation and Switching Station Erection Contract," generally required for systems with limited construction forces
9. Design approval by RUS as stated in 7 CFR 1724.54 "Requirements for RUS approval of plans and specifications"
10. Selection of a construction contractor
11. Construction
12. Inspection; see RUS Form 235, "Engineering Service Contract—Electric Substation Design and Construction," and 7 CFR 1726.403, "Project Construction Contract Closeout"
13. Testing
14. Energizing

When competitive bids are to be received for substation construction, the engineer's role is that described in 7 CFR 1726.19, "Use of Competitive Procurement." See also RUS Form 764, "Substation and Switching Station Erection Contract."

Consultation with the RUS General Field Representative (GFR) may provide useful information and assistance with pertinent RUS requirements.

3.4 PROCUREMENT

The methods and documentation for obtaining substation equipment are as follows:

1. Purchase order following informal quotations
2. Contract and purchase order following formal competitive bidding

Guidelines and procedures applicable to the selection of materials and equipment include the following documents:

- 7 CFR 1728, "Electric Standards and Specifications for Materials and Construction"
- 7 CFR 1726.22, "Methods of Construction"
- Information Publication 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers"
- 7 CFR 1726.21, "New Materials"
- Bulletin 43-9, "'Buy American' Requirement," as updated per notice published in the Federal Register on February 19, 1997, at 62 FR 7205
- 7 CFR 1728.20, "Establishment of Standards and Specifications"

The size and complexity of a project can greatly influence the choices in procurement. Lead times for procurement of major and/or special equipment in many cases may favor incremental purchases of equipment.

Smaller projects may lend themselves more to "standard package"-type procurement while the procurement for larger projects may require many vendors.

3.5 DRAWINGS

3.5.1 General

For a basic distribution substation, a "One-Line Diagram" and "Plot Plan" may be the only drawings that need to be custom made by the engineer. For example, if a substation is small, it may be possible to show foundation details on the "Plot Plan." Similarly, the grounding layout and details might also be shown on a "Plot Plan."

Larger substations will, of necessity, require more extensive documentation. RUS Form 235, "Engineering Services Contract—Electric Substation Design and Construction," details a basic list of drawings often necessary.

3.5.2 Quality

3.5.2.1 Substation drawings of any kind should conform to industry accepted quality requirements.

3.5.2.2 Drafting Practice: It is recommended that drafting practices be in accordance with *American Drafting Standards Manual*, ANSI Std. Y14. Prints of the drawings will be used in construction, not always under the most convenient environmental conditions. Experience indicates a preference for equipment outlines with detailed pictorial representations. Pertinent component interfaces and connections should be illustrated in adequate detail for construction and record purposes. The dimensions of pertinent distances need to be shown. Drawings, though made to scale, should not have to be scaled for construction purposes. Thought should be given to choosing scales and lettering sizes appropriate for the type of drawing. It would be desirable to use bar-type graphic scales on all drawings since many of them may be reproduced in different sizes. Plans, elevations, and sections should be organized for maximum clarity. Tolerances should be noted on drawings, such as those that specify foundation anchor bolt locations and equipment mounting holes on control panels. Simplicity and clarity of drawings are essential.

3.5.2.3 Computer Drafting/Computer-Aided Design and Drafting (CADD)

3.5.2.3.1 <u>General</u>: Since the early 1980s the use of CADD has exploded. With proper planning, CADD is a very productive tool. Virtually all modern substations are now designed on CADD systems.

3.5.2.3.2 <u>Startup</u>: Parameters need to be established before the creation of any drawings with CADD. These parameters are basic to CADD and permit CADD to make use of its strength and flexibility to produce quality products. These parameters will ultimately lead to the increased productivity that users expect from CADD:

1. Establish or revise key drawing criteria. The engineer needs to know what is to be shown on each drawing.
2. Establish legends for the symbols that will be used.
3. Standardize the line weights and text sizes.
4. Establish standard layer or level schemes.
5. Provide for the ability to isolate layers and reference other files.
6. Provide for the ability to make changes on one file and have the changes reflected on related drawings, eliminating having to change the other drawings.
7. Establish a cell library or blocks, in a location for standard files, of items that will be continually reused in the cooperative's drawings.
8. Create seed files or prototype files that may be used as the base for drawing preparation.

3.5.2.3.3 <u>Detailing Guidelines</u>: The use of CADD generates new considerations and requires new guidelines. However, good manual detailing practices such as the following still apply to computer detailing:

1. Draw everything to scale if possible.
2. Use good clear dimensioning.
3. Carefully select line weights and text sizes. Use standard sizes where applicable.
4. Do not overdetail drawings with the use of CADD. It makes no sense to show the threads on the bolts just because you can.
5. Use the cooperative's standard detailing manuals and procedures, or coordinate with other key design and detailing personnel in the cooperative.
6. If you wouldn't show a detail with ink on mylar, it should not be drawn with CADD software.
7. Avoid translations. CADD software will seldom translate drawings prepared by another vendor's software completely accurately. It's always best to use the cooperative's standard CADD software.
8. Avoid mixing drawings from different CADD packages on a project or within a cooperative. The use of several different CADD packages within an organization will tend to lead to confusion in detailing.

3.5.2.4 Legends, Notes, and Symbols: Put a definitive legend on the first sheet of each type of drawing. This legend should not only include the standard symbols, but all special symbols or designations. A set of notes is often found to be a desirable supplement on a drawing. Use judgment to avoid overdoing notation. It may be better to consider additional details on the drawings rather than a long list of notes. Electrical symbols should be in accordance with IEEE Std. 315, "Graphic Symbols for Electrical and Electronics Diagrams."

3.5.2.5 Reference Drawings: Give proper care to the listing of reference drawings to ensure a coherent, concise pattern.

3.5.2.6 Titles: Make drawing titles concise, accurate, and specific. They should not be so general that the drawing itself has to be viewed to see what it covers.

3.5.2.7 Approvals: Ensure that every drawing or revision to a drawing indicates the proper approvals and dates.

3.5.3 Types of Drawings

Following are the main types of substation construction and reference drawings often required. Appendix A to this chapter includes checklists covering the content of some types of drawings. It is recommended that the engineer use checklists as a design quality control tool.

1. One-Line Diagram - Switching
2. One-Line Diagram - Functional Relaying
3. Three-Line Diagram
4. Electrical Plot Plan
5. Site Preparation
6. Fence Layout
7. Electrical Layouts
8. Structure Erection Diagrams
9. Foundation Layouts
10. Grounding Layout
11. Conduit Layout
12. Control House - Architectural, Equipment, Layout, Lighting, Etc.
13. Station Service Diagrams AC and DC
14. Cable Lists and Conduit Lists
15. Bills of Material
16. Drawing List
17. Control Panels
18. Schematic and Detailed Wiring Diagrams

3.5.3.1 One-Line Diagrams: One-line diagrams serve as the major substation reference drawings and require special emphasis. These references should be the first drawings prepared. The switching and functional relaying information may appear on the same one-line diagram if the presentation is not too complicated. It is recommended that one-line diagrams be prepared utilizing the "Typical Substation Drawing Checklist" that is included in Appendix A.

Acceptable symbols for some of the most common substation equipment are illustrated in Figures 3-1 through 3-19. Generally, these symbols are based on IEEE Std. 315. Drafting templates are commercially available to assist in developing one-line diagrams. Each symbol should be accompanied by the pertinent equipment information indicated.

MANUFACTURER
TYPE   OA/FA/FOA ETC. AS APPLICABLE
CAPACITY   (_/_/_ MVA)
VOLTAGE   (_/_/_/ETC _/_-_ KV)
IMPEDANCE   (__ OHMS HV-LV)
                    (SHOW PHASING AND TERMINAL
                    DESIGNATION ON VECTORS)
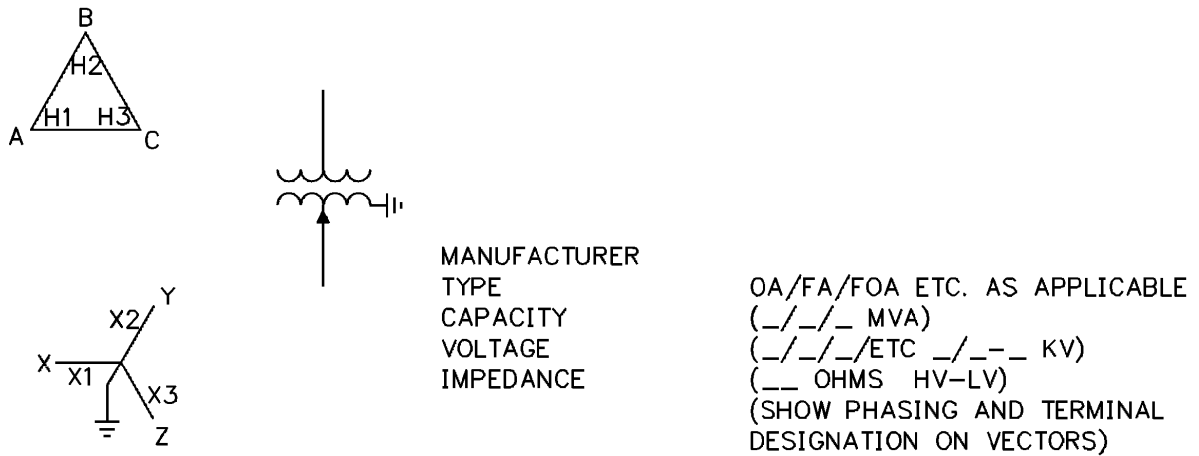
Figure 3-1: Power Transformer (Shown with Load Tap Changer on Low-Voltage Side). Ref. IEEE Std. 315 based on Figs. 6.4.9, 1.9.3, 1.9.7.1, and 3.9.1. Copyright © 1975. IEEE. All rights reserved.

INFORMATION SAME AS FIGURE 3-1 EXCEPT
INCLUDE ALL IMPEDANCES
(HV-LV __% ON __ MVA BASE)
(HV-TV __% ON __ MVA BASE)
(LV-LV __% ON __ MVA BASE)
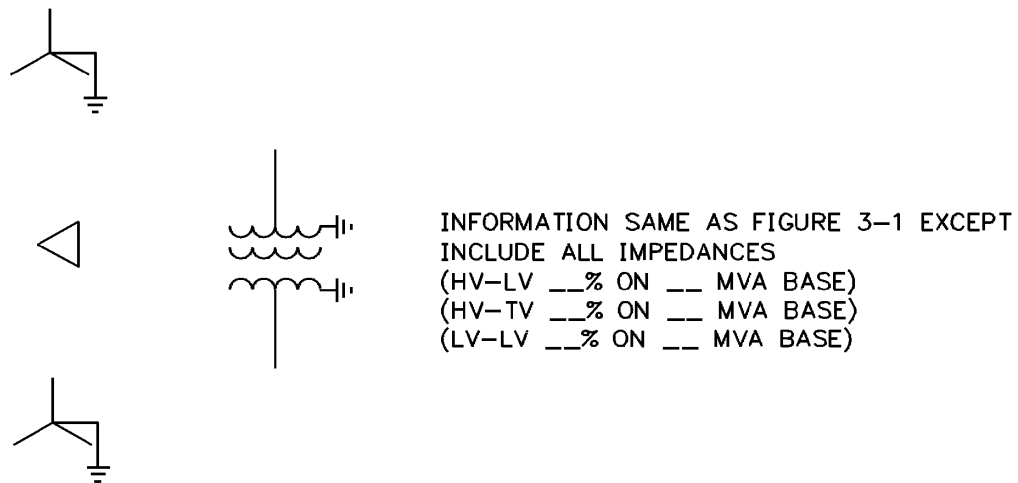
Figure 3-2: Three-Phase Transformer with Tertiary. Ref. IEEE Std. 315. Based on Figs. 6.4.17, 1.9.3, 1.9.7.1, and 3.9.1. Copyright © 1975. IEEE. All rights reserved.
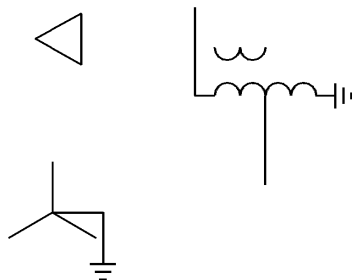
Figure 3-3: Three-Phase Auto-Transformer. Ref. IEEE Std. 315. Based on Figs. 6.4.8, 1.9.3, 1.9.7.1, and 3.9.1. Copyright © 1975. IEEE. All rights reserved.

NO. — MFR — TYPE

__ A   __KV

MFR — TYPE

__ ∅
__ KVA   __ A
__ KV   __ %
__ KV BIL
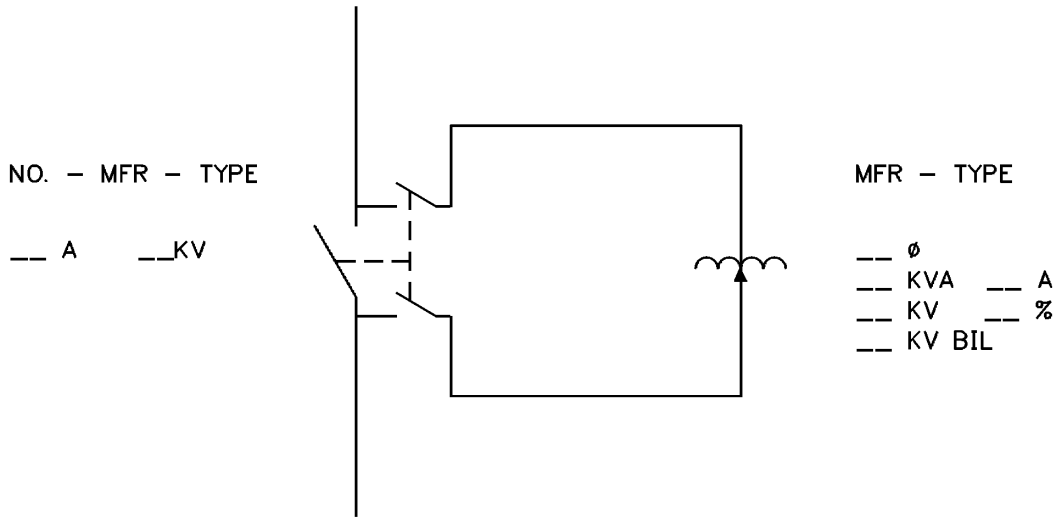
Figure 3-4: Step Voltage Regulator with Bypass Switch.
Ref. IEEE Std. 315. Based on Figs. 6.4.10.1, 4.6.1, and 14.4.1.

3 — MFR — TYPE
__ A   __ KV
__ KV BIL
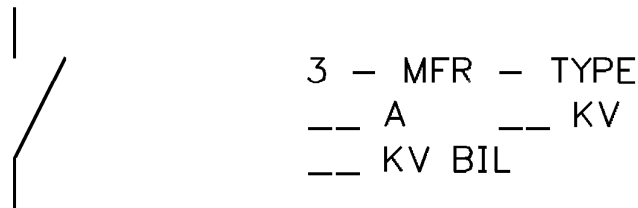
Figure 3-5: Hook Stick-Operated Disconnecting Switch.
Ref. IEEE Std. 315. Figure 4.6.1.

MFR — TYPE
__ A   __ KV
__ KV BIL

Figure 3-6: Three-Phase Gang-Operated Disconnecting Switch with Horn Gaps
and Grounding Switch. Ref. IEEE Std. 315. Figs. 4.6.1, 4.6.6, and 3.9.1.

MFR — TYPE
__ A   __ KV
__ KV BIL
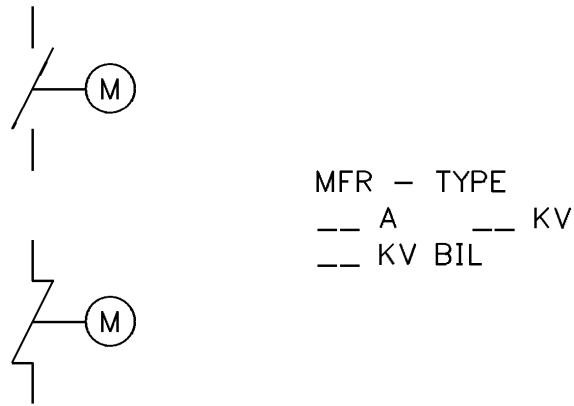
Figure 3-7: Three-Phase Double Side-Break Disconnecting Switch with Motor Operator.
Ref. IEEE Std. 315. Based on Figs. 13.1.3 and 4.6.1. Copyright © 1975. IEEE. All rights reserved.

1 OR 3 — MFR — TYPE

__ A   __ KV
__ A LINK (OR MFR CAT. NO.)
__ KV BIL
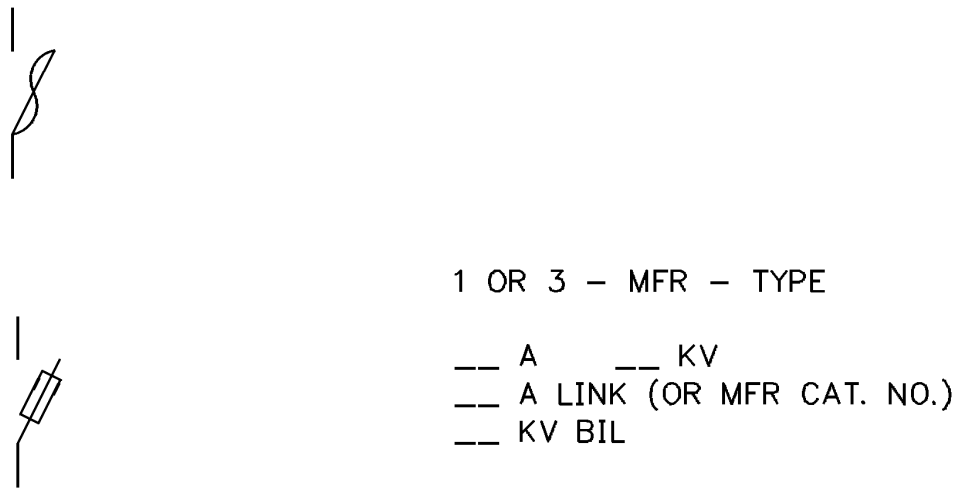
Figure 3-8: Fused Disconnect. Ref. IEEE Std. 315. Figs 9.1.1 and 9.1.3.
Copyright © 1975. IEEE. All rights reserved.

1 OR 3 — MFR — TYPE — 1 OR 3ø

__ A   __ KV
__ KV BIL
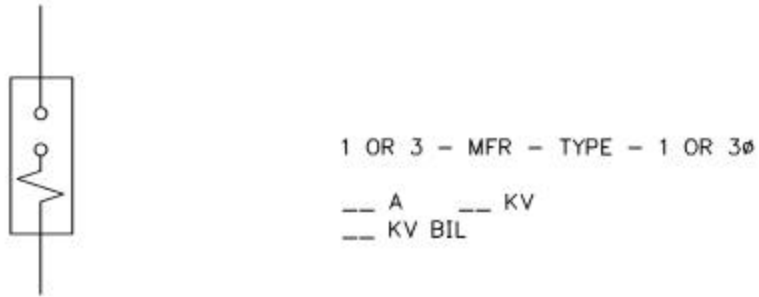
Figure 3-9: Oil Circuit Recloser. Ref. IEEE Std. 315. Based on Fig. 9.4.6.
Copyright © 1975. IEEE. All rights reserved.

1200—5A MR
400—5A CONN.

DEPICTS
MECH. END

79

MFR — TYPE

__ A   __ KV
__ A INT. CAP.
__ KV BIL

__ —5A MR
__ —5A CONN.

* INTERRUPTING MEDIUM

A FOR AIR
O FOR OIL
V FOR VACUUM
G FOR GAS
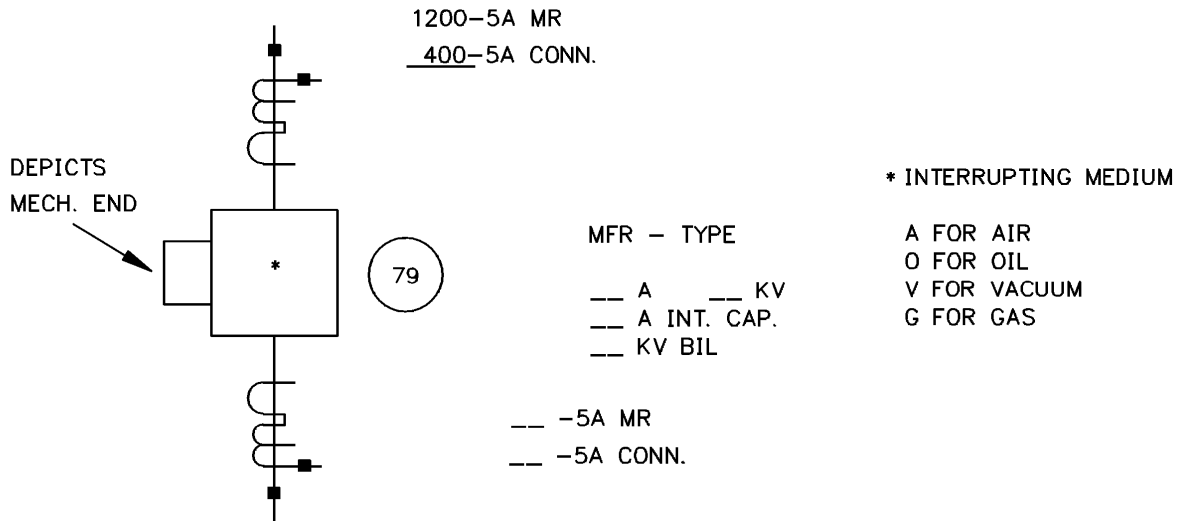
Figure 3-10: Circuit Breaker (Shown with Bushing-Type CTs and Reclosing Relay).
(Show Polarity Marks on One-Line Functional Relaying Diagram.)
Ref. IEEE Std. 315. Based on Figs. 9.4.4, 6.4.19, and 4.5.3.
Copyright © 1975. IEEE. All Rights Reserved.

3 — MFR — TYPE

__ KV   _____ CLASS
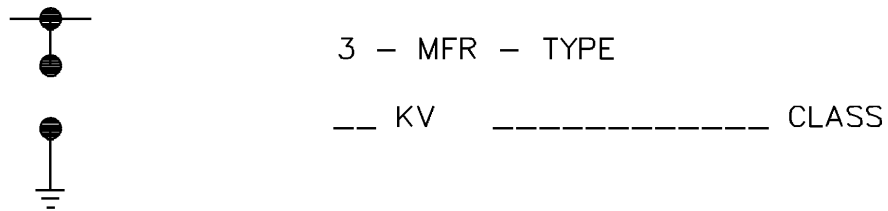
Figure 3-11: Surge Arrester. Ref. IEEE Std. 315. Based on Figs. 9.3.1 and 3.9.1.
Copyright © 1975. IEEE. All rights reserved.
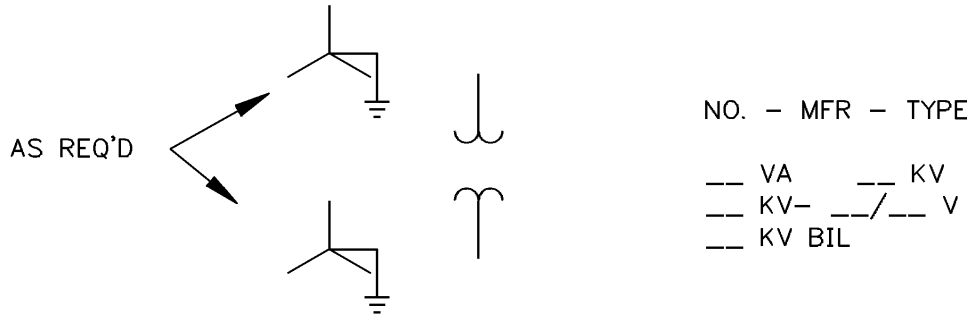
Figure 3-12: Voltage Transformer. Ref. IEEE Std. 315. Based on Figs. 3.9.1, 6.4.20, and 1.9.7.1.
Copyright © 1975. IEEE. All rights reserved.
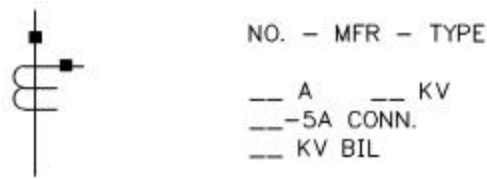
Figure 3-13: Current Transformer. (Show Polarity Marks on Functional
Relaying One-Line Diagram.) Ref. IEEE Std. 315. Figs 6.4.18 and 1.6.3.1.
Copyright © 1975. IEEE. All rights reserved.
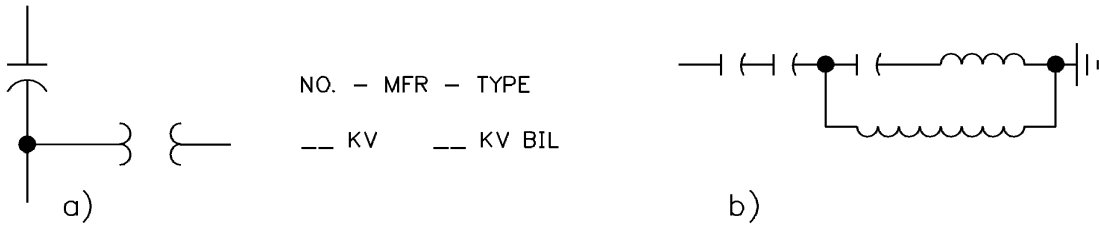
Figure 3-14: Coupling Capacitor with Voltage Transformer. Ref. IEEE Std. 315.
Based on Figs. 2.2.1, 2.2.15, and 6.2.7.1. Copyright © 1975. IEEE. All rights reserved.
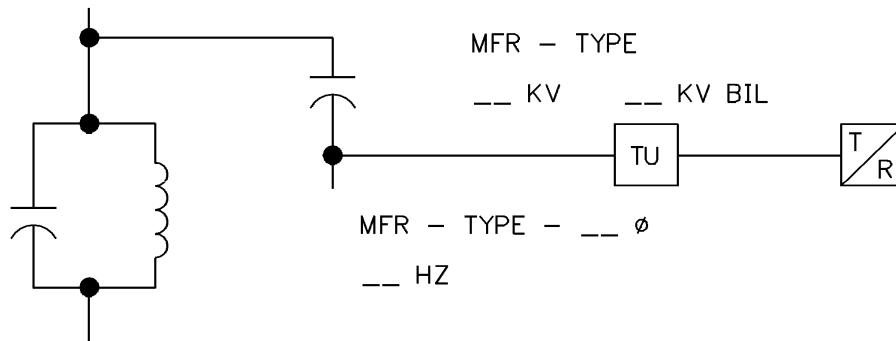
Figure 3-15: Coupling Capacitor, Wave Trap, Tuning Unit, and Power Line Carrier
Transmitter/ Receiver. Ref. IEEE Std. 315. Based on Figs. 6.2.8.1 and 2.2.12.
Copyright © 1975. IEEE. All rights reserved.
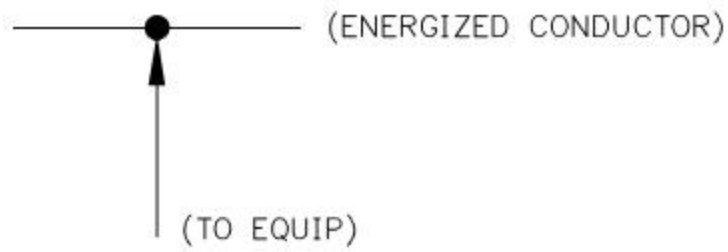
Figure 3-16: Disconnecting Clamp. Ref. IEEE Std. 315.
Based on Fig. 3.3.1. Copyright © 1975. IEEE. All rights reserved.
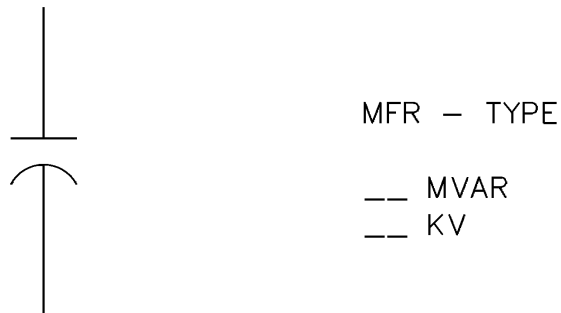
Figure 3-17: Shunt Capacitor. Ref. IEEE Std. 315. Fig. 2.2.11.
Copyright © 1975. IEEE. All rights reserved.
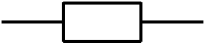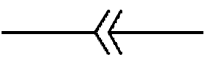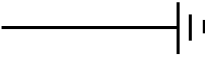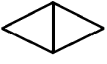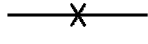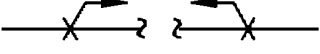
≪⌒≫	DRAWOUT VACUUM MED. VOLTAGE POWER CIRCUIT BREAKER
⌒	CIRCUIT BREAKER (LOW VOLTAGE)
▭	RESISTANCE OR HEATING ELEMENT
⌇⌇⌇	REACTOR
≪	DISCONNECT ON DRAWOUT CONNECTION
⊦	GROUND CONNECTION
◇	STRESS RELIEF DEVICE
✕	TEST SWITCH (POT. OR ISOLATION)
✕ ✕	TEST SWITCH (CURRENT SHORTING)
Ⓛ1	INDICATING LIGHT
⊘	FIBER-OPTIC CIRCUIT
←	MICROWAVE PATH

Figure 3-18: One-Line Diagram Symbols. Ref. IEEE Std. 315.
Based on Figs. 5.3.4, 9.4.1, 2.1.1, 6.2.1, 3.9, and 1.3.1.
Copyright © 1975. IEEE. All rights reserved.

Figures 3-20, 3-21, and 3-22 provide elementary examples of symbols in combination. Figure 3-20 shows a conceptual one-line diagram of a transmission substation. Figure 3-20 is provided merely to illustrate use of some of the symbols. Figures 3-21 and 3-22 combined provide a more complete example of equipment usage for Line 161-20. It may be observed that equipment shown on Figures 3-21 and 3-22 hardly exhausts the possibilities of equipment application for a 161 kV line. Figures 3-21 and 3-22, moreover, indicate the desirability of having both switching and relaying one-line diagrams except for the simpler substations.

ARROW INDICATES
DIRECTION OF TRIPPING

TO OTHER RELAYS OR
METERS AS REQUIRED

POTENTIAL CONNECTIONS, AS
REQUIRED, AT RIGHT ANGLES
TO CURRENT CONNECTIONS

TO POTENTIAL
SOURCE
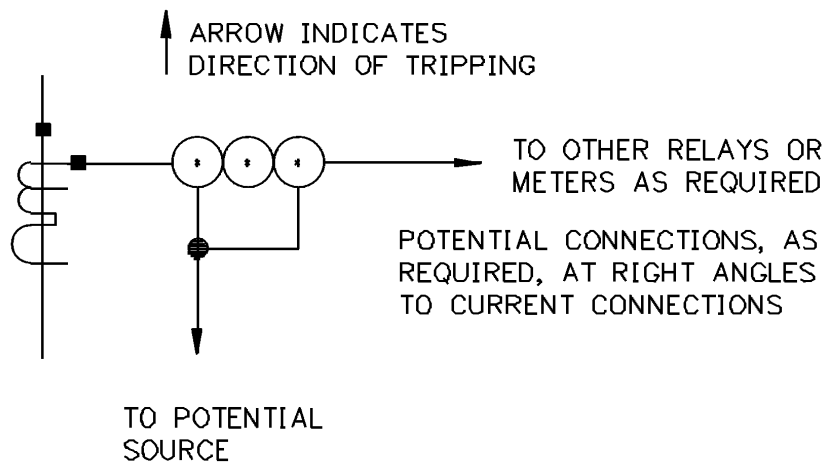
* A PARTIAL LISTING OF DEVICES AS FOLLOWS:

   A   (FOR AMMETER)
   V   (FOR VOLTMETER)
   W   (FOR WATTMETER)
 WH (FOR WATT-HOUR METER)
VAR (FOR VOLT AMPERE REACTIVE METER)

OR A NUMBER IN ACCORDANCE WITH ANSI STD. C37.5
SUCH AS THE FOLLOWING COMMONLY USED NUMBERS:

21 (DISTANCE RELAY)
27 (UNDERVOLTAGE RELAY)
32 (DIRECTIONAL POWER RELAY)
50 (INSTANTANEOUS OVERCURRENT RELAY)
51 (AC TIME OVERCURRENT RELAY)
67 (AC DIRECTIONAL OVERCURRENT RELAY)
74 (ALARM RELAY)
87 (DIFFERENTIAL PROTECTIVE RELAY)

Figure 3-19: Typical Relay and Meter Representation. Ref. IEEE Std. C37.2-1996.
Copyright © 1975. IEEE. All rights reserved.
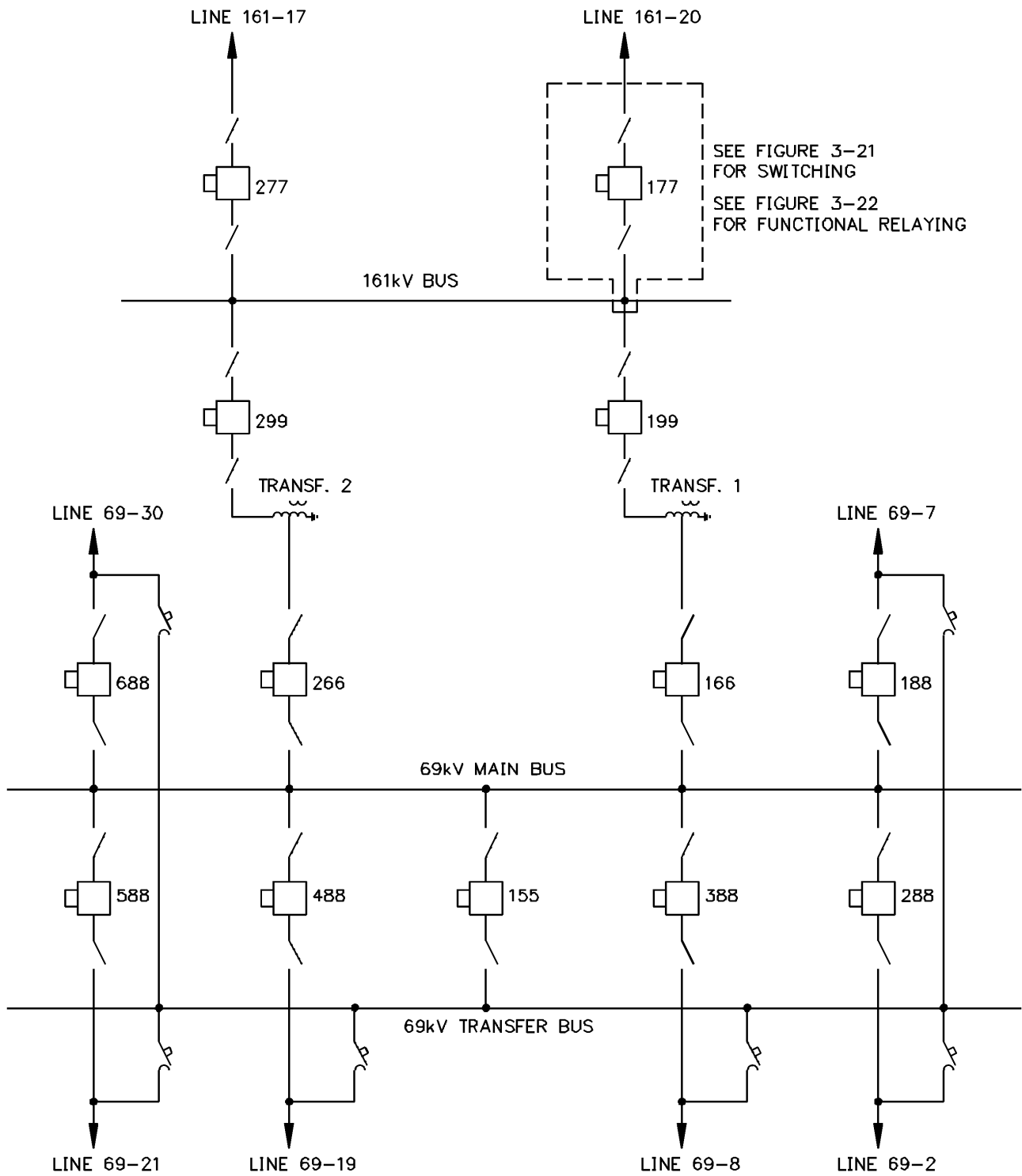
Figure 3-20: Conceptual One-Line Diagram

LINE 161-20

3/0 ACSR

MFR., TYPE

795 KCMIL
ACSR

MFR.-TYPE-Aø
100Hz

795 KCMIL
ACSR

178

MFR., TYPE
1600A., 161kV
750 kV BIL

177

MFR., TYPE
1600A., 169kV
31,500A. INT. CAP.
750 kV BIL

795 KCMIL
ACSR

MFR., TYPE
1600A., 161kV
750 kV BIL

3" AL   3" AL
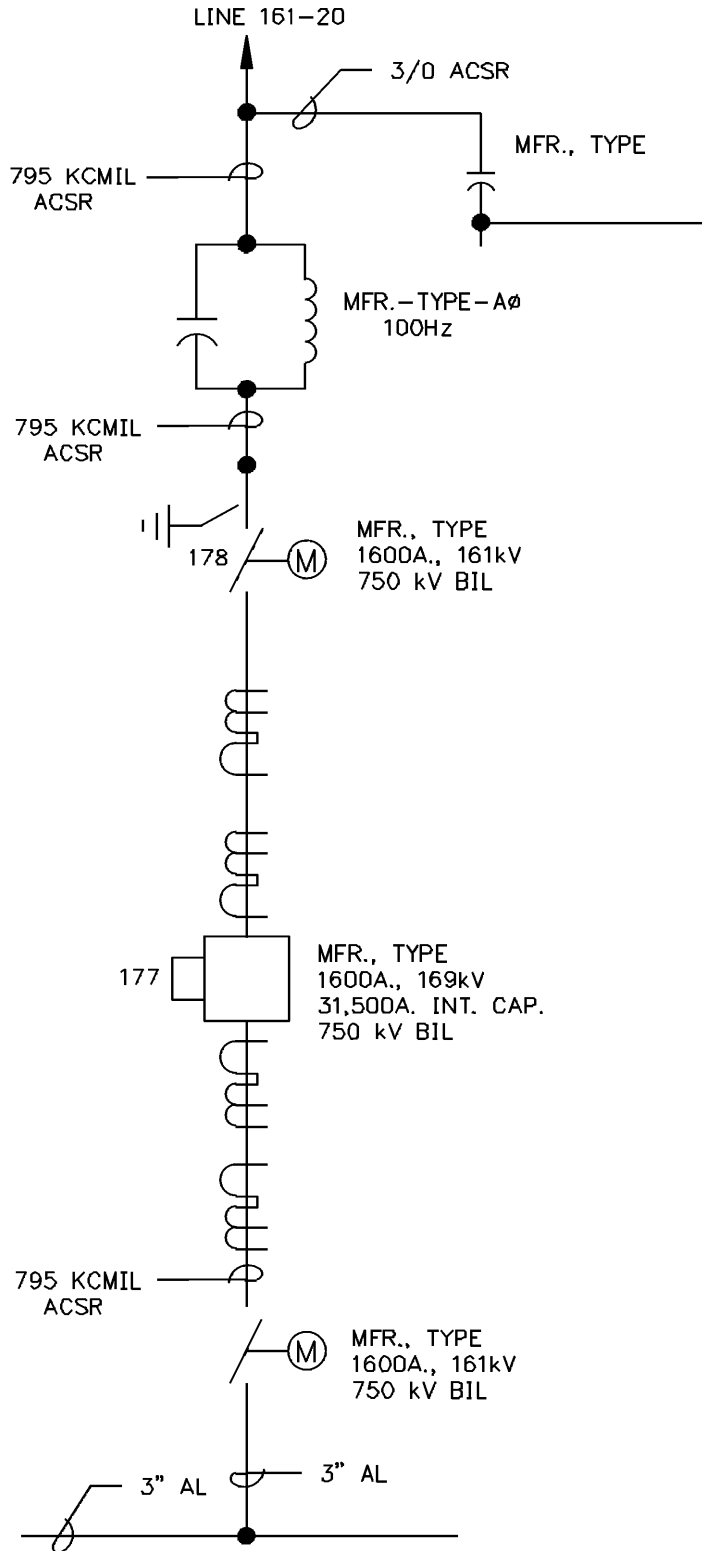
Figure 3-21: Partial Switching One-Line Diagram (See Figure 3-20)

LINE 161-20

TU
MFR. TYPE

T/R
MFR. TYPE
100 Hz

LINE
TRAP

BUS DIFFERENTIAL RELAYING

2000-5A MR
500-5A CONN

2000-5A MR
200-5A CONN

BACKUP RELAYING

T

C 79 25/27 94 PRIMARY RELAYING

2000-5A MR
800-5A CONN

21-3 21-2 3 A 67 50G 3 67 50G 3

2000-5A MR
600-5A CONN

METERING

POTENTIAL
SOURCES

161kV   BUS
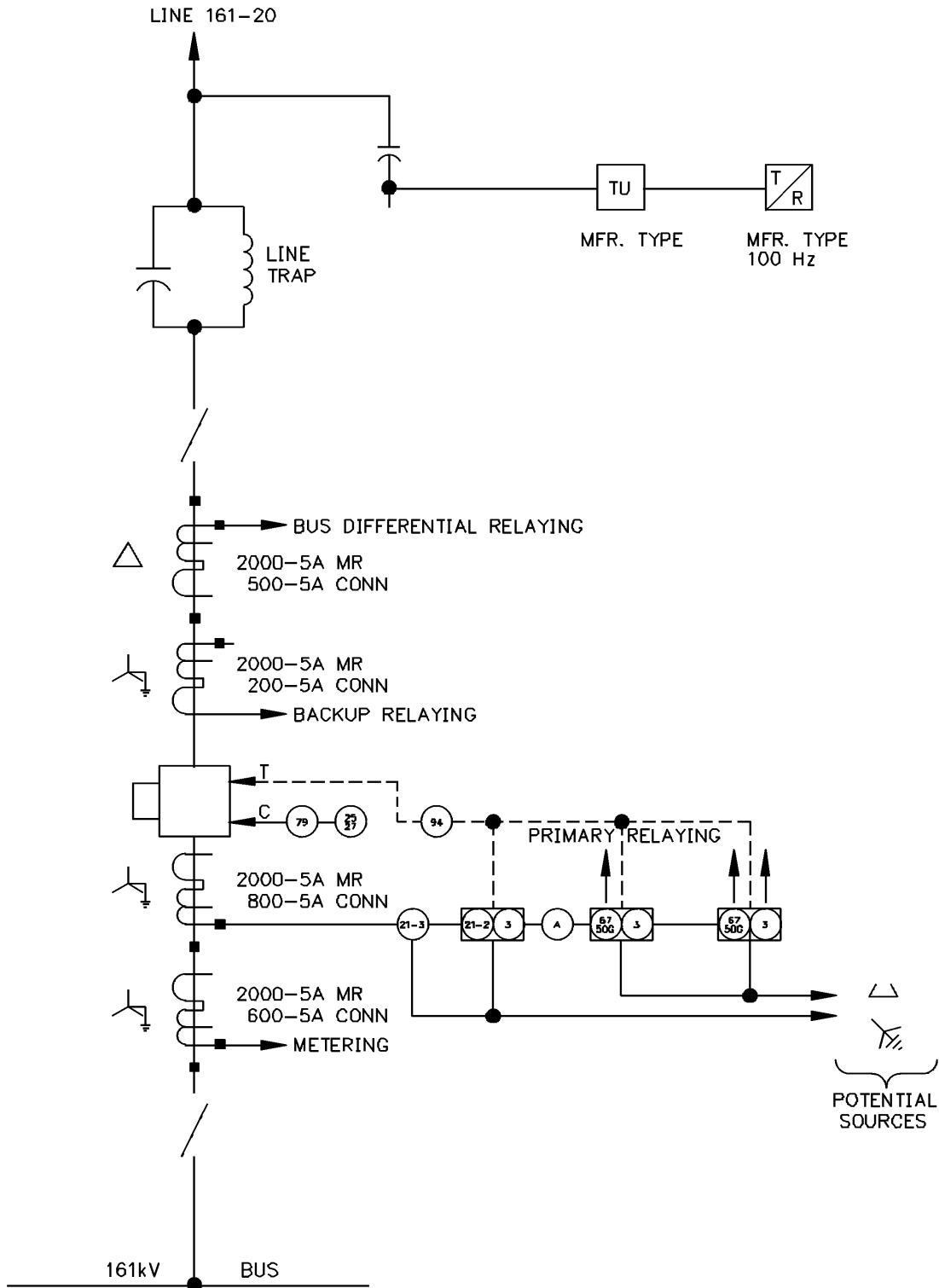
Figure 3-22: Partial Functional Relaying One-Line Diagram (See Figure 3-20)

3.5.3.2 Cable Lists and Conduit Lists: Cables may be identified on a drawing, such as a conduit layout, if the number of cables is not large. On large stations, it generally is desirable to have a separate cable identification list. A cable identification system should be devised to indicate the location of one end of each cable and the function of the cable. An alphanumeric designation often works well. In such a system, C4-3 could be a cable from a circuit breaker at location C4 on a grid system where C designates an equipment row centerline in a series A, B, C, D, etc., and 4 designates a row centerline in a series 1,2,3,4,5,6, etc., at a right angle to centerline C. The -3 could represent a cable for control.

Different arabic numerals could be used for other functions.

3.5.3.3 Bills of Material: As a general rule, all elements of work in a substation should have a list of material. When such lists comprise a multisheet drawing, they are known as Bills of Material. Formats should be devised to include the following information as a minimum:

1. Identification of the substation
2. Alphanumeric code name for items that may appear on a construction drawing for identification and location
3. Adequate description of each item
4. Reference to the applicable purchasing document
5. Quantity of the item
6. Reference to drawing(s) on which the item is shown for installation

3.5.3.4 Drawing List: It is recommended that every substation have a drawing list that includes, at the cooperative's and engineer's discretion, manufacturers' drawings, design calculations, the cooperative's standard drawings, etc.

3.5.3.5 Schematic and Detailed Wiring Diagrams: These wiring diagrams should be prepared following the guidelines in ANSI Std. Y14.15, "Electrical and Electronic Diagrams."

3.6 STUDIES

For many substations, it will be necessary to make a number of studies such as feasibility studies, economic comparisons, voltage drop calculations for control and auxiliary power circuits, rigid and strain bus design comparisons, structural design calculations, etc. The results of these studies along with the calculations should be retained with other documents relating to the particular substation.

3.7 REFERENCES

7 CFR 1710.119, "Loan Processing Priorities."

7 CFR 1724.53, "Preparation of Plans and Specifications."

7 CFR 1726.19, "Use of Competitive Procurement."

7 CFR 1726.21, "New Materials."

7 CFR 1726.22, "Methods of Construction."

7 CFR 1726.35, "Submission of Documents to RUS."

7 CFR 1726.403, "Project Construction Contract Closeout."

7 CFR 1728, "Electric Standards and Specification for Materials and Construction."

7 CFR 1728.20, "Establishment of Standards and Specifications."

ANSI Std. C37.2, "Standard for Electrical Power System Device Function Numbers and Contact Designations."

ANSI Std. Y14, *American Drafting Standards Manual.*

ANSI Std. Y14.15, "Electrical and Electronic Diagrams."

IEEE Std. 315, "Graphic Symbols for Electrical and Electronic Diagrams."

RUS Bulletin 43-9, "Buy American Requirement."

RUS Form 235, "Engineering Service Contract—Electric Substation Design and Construction."

RUS Form 764, "Substation and Switching Station Erection Contract."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

APPENDIX A

TYPICAL SUBSTATION DRAWING CHECKLIST

GENERAL – FOR ALL DRAWINGS
A. COVER SHEET/INDEX
B. LEGEND
C. ELEMENTARY ONE-LINE DIAGRAM(S)
D. RELAY ONE-LINE DIAGRAM(S)
E. GENERAL ARRANGEMENT PLAN
F. SITE PLANS, SECTIONS, AND DETAILS
G. SUBSTATION PLAN, SECTIONS, AND DETAILS
H. FOUNDATION PLAN AND DETAILS
I. STRUCTURE PLAN AND DETAILS
J. GROUNDING PLAN AND DETAILS
K. RACEWAY PLAN AND DETAILS
L. DUCT BANK AND HIGH-VOLTAGE CABLE PLAN AND DETAILS
M. CONTROL BUILDING PLANS, SECTIONS, AND DETAILS
N. SUBSTATION BILL OF MATERIALS
O. RELAY CONTROL PANEL (SWITCHBOARD) LAYOUTS AND WIRING DIAGRAMS
P. THREE-LINE DIAGRAMS, AC AND DC SCHEMATICS
Q. MISCELLANEOUS EQUIPMENT YARD EXTERNAL CONNECTION DIAGRAMS

GENERAL - FOR ALL DRAWINGS

_____ 1. Title block.
_____ 2. Engineer's seal (verify whether engineer needs to sign the seal).
_____ 3. Drawing dates (input date the drawing is issued for owner approval).
_____ 4. Revision block.
_____ 5. Signature lines:
_____   a. Detailed - Detailers name (i.e., J.A. JONES) who initially made the drawing.
_____   b. Designed - Design engineer's name (i.e. T.R. SMITH).
_____   c. Checked - Initials (i.e., L.M.F.) of the engineer who checked the drawing; the same engineer may not check all contract drawings.
_____ 6. Symbology is correct per Legend drawing.
_____ 7. Drawing coordinate system is provided on border margins.
_____ 8. Drawing is of material satisfactory to the cooperative.
_____ 9. Drawing is of a size satisfactory to the cooperative.
_____ 10. Drawing is identified as satisfactory to the cooperative.
_____ 11. All line work and lettering are reproducible.
_____ 12. The smallest lettering is readable at the smallest proposed reduction size.
_____ 13. Consideration has been given to overall organization of drawing to minimize field inconvenience.
_____ 14. Drawing avoids ambiguities, incompleteness, lack of clarity, misleading emphasis, etc.
_____ 15. Legends, notes, symbols have been carefully reviewed for correctness and completeness.
_____ 16. Appropriate drawings are referenced.
_____ 17. All changes are incorporated as required by the cooperative or RUS.
              Additional for Plan, Sections, Elevations, Details, and Panel Layouts.
_____ 18. Bar scale (engineer's scale only).
_____ 19. Detail, Section, or Elevation Designation and Title.
              Additional for Plan, Drawings, Detail Plan Views, One-Line and Three-Line diagrams.
_____ 20. North arrow (reference to grid, true, or magnetic north).

A. COVER SHEET/INDEX (MAY BE MORE THAN ONE DRAWING)

_____ 1. Engineer's seal
_____ 2. Cooperative name
_____ 3. Cooperative logo
_____ 4. Project description
_____ 5. Contract number and name
_____ 6. List of contract drawings
_____ 7. Vicinity map (with north arrow)
_____ 8. List of reference drawings
_____ 9. Project number
_____ 10. Year

B.   LEGEND

Include the "General - for All Drawings" items.

            1.   List of all symbols used for the drawings (do not have individual legends on other drawings with the exception of complex Civil Site Grading Plans).

C.   ELEMENTARY ONE-LINE DIAGRAM(S)

Include the "General - for All Drawings" items

_____   1.   Substation names and voltages
_____   2.   Breakers with PCB numbers
_____   3.   Disconnect switches with numbers
_____   4.   Line/major equipment designations
_____   5.   Phasing
_____   6.   Future equipment
                7.   Transmission lines:
_____   a.   Length
_____   b.   Conductors/stranding
_____   c.   Transpositions
_____   8.   Bus and relative location, physically oriented as possible
_____   9.   Interties to interconnecting utilities - phasing difference between utilities
_____   10. Power fuses
_____   11. Other information needed from a switching standpoint to define overall system

D.   RELAY ONE-LINE DIAGRAM(S)

Include the "General - for All Drawings" items.

                1.   Power One-line:
_____   a.   Incoming lines/designations and voltages
_____   b.   Disconnect switches and numbers
_____   c.   Surge arresters/quantity and rating
                        d.   Power transformers (in equipment box):
_____   (1)   Winding type - auto or multiple winding and tertiary
_____   (2)   Surge arresters
_____   (3)   Phasing
_____   (4)   Bushings/designations
_____   (5)   Neutral/ground connection
                        (6)   Transformer designations:
_____   (a)   Voltage rating
_____   (b)   MVA rating
_____   (c)   Cooling rating
_____   (d)   HV taps
_____   (e)   LV taps
_____   (f)   LTC (if applicable)
_____   (g)   Impedance for all winding connections
_____   (h)   Winding connection diagram indicating phasing and voltage relationships at bushings
_____   2.   Power fuses w/ continuous current rating
                3.   Station service transformer:

_____   a.   Quantity
_____   b.   kVA rating
_____   c.   Transformer type
_____   d.   Voltage ratings
_____   e.   Taps
_____   f.   Secondary breaker or fuse if located in yard near transformer
_____   g.   Reference to low-voltage AC drawing
_____   4.   High-voltage bus with designations on main bus and phasing, connection dots

5.   Power circuit breakers:
_____   a.   Bushing pole numbers
_____   b.   Cabinet location
_____   c.   Designation
_____   d.   Continuous current rating
_____   e.   Breaker number

6.   CCVTs, CVTs, or PTs:
_____   a.   Primary winding
_____   b.   Secondary winding with terminal designations
_____   c.   Quantity (if more than one)
_____   d.   Phase designation
_____   e.   Voltage rating for all windings
_____   f.   Ratio for all windings
_____   g.   Capacitance of device

7.   Line traps
_____   a.   Designation
_____   b.   Phase location
_____   c.   Continuous current rating

8.   Miscellaneous equipment:
_____   a.   Correct symbol per legend
_____   b.   Designation
_____   c.   Phasing
_____   d.   Quantity (if more than one)
_____   e.   Major equipment ratings

9.   Miscellaneous:
_____   a.   Future bus connections
_____   b.   Temporary bus connections:
          1.   Clear differentiation between permanent -vs- temporary
_____   2.   Different phases of construction (permanent -vs- temporary)
_____   c.   References to other drawings
_____   d.   Bill of material #'s for major equipment
_____   e.   Drawing coordinate system

10.   Protection/controls:
     a.   Current transformers/circuits:
_____   (1)   Correct orientation of symbol
_____   (2)   Multi ratio -vs- single ratio
_____   (3)   Polarity marks
_____   (4)   Symbol for wye or delta connection
_____   (5)   Quantity (if more than one)
_____   (6)   Maximum ratio for multi-ratio
_____   (7)   Ratio combinations for dual rated CTs
_____   (8)   Connected ratio

       _____ (9) Shorted if not used
       _____ (10) Circuits short as possible to minimize confusion
       _____ (11) Fewest line crossings as possible to minimize confusion
       _____ (12) Straight through devices - in and out
       _____ (13) Test plug arrows pointed properly
       _____ (14) Polarizing currents in and out on 45 degree angle

b. Potential circuits:
       _____ (1) Potential device secondary winding
       _____ (2) Potential device secondary connections
       _____ (3) Fuses and contact current ratings
       _____ (4) Test points as appropriate
       _____ (5) Into instruments on a square angle
       _____ (6) Short as possible to minimize confusion
       _____ (7) Fewest line crossings as possible to minimize confusion

c. Equipment enclosure boxes:
       _____ (1) Transformers
       _____ (2) Fuse and terminal boxes
       _____ (3) Designations and phasing as applicable

d. Instruments:
       _____ (1) Circle or box per legend
       _____ (2) Designations or suffixes per legend
       _____ (3) Location symbol
       _____ (4) Quantity (if more than one)

e. Control logic:
       _____ (1) Short as possible to minimize confusion
       _____ (2) Fewest line crossings as possible to minimize confusion
       _____ (3) Arrowhead toward the direction of action
       _____ (4) Arrowhead only where action splits or comes together for a common function
       _____ (5) Contact designations where applicable to show correct logic
       _____ (6) Diodes where applicable and used to control the logic
       _____ (7) If not obvious, primary action of control identified (Trip, etc.)

E. GENERAL ARRANGEMENT PLAN

Include the "General - for All Drawings" items.

                  1. First transmission structure outside the fence, minimum, with location coordinates
       _____ 2. Minimum of two survey monuments with elevations and dimensions to the substation base lines
       _____ 3. Coordinates (or dimensions to base line) of centerline of transmission line termination structure
       _____ 4. Transmission line voltage and name
       _____ 5. Transmission line right-of-way with tie into substation monuments
       _____ 6. Property lines and other utility corridors or rights-of-way
       _____ 7. Baseline
       _____ 8. Borrow and waste area
       _____ 9. Trash area
       _____ 10. Storage areas

_____ 11. Site access
_____ 12. Vicinity map with ties to state plane coordinates

F.   SITE PLANS, SECTIONS, AND DETAILS

Include the "General - for All Drawings" items.

    1.   Site Plan/Grading Plan:
_____   a.   Baseline
_____   b.   Benchmark
_____   c.   Fence coordinates
_____   d.   State plane grid system
_____   e.   New and existing grade
_____   f.   Buried facilities
_____   g.   Borrow area
_____   h.   Access roads
    2.   Site Sections/Grading Sections and Details:
        a.   Sections:
_____   (1) Fence location
_____   (2) Baseline location
_____   (3) Elevations
_____   (4) New and existing grade
_____   b.   Fence details
_____   c.   Gate details

G.   SUBSTATION PLAN, SECTIONS, AND DETAILS

Include the "General - for All Drawings" items.

    1.   Substation Plan:
_____   a.   Fence
_____   b.   Warning signs
        c.   Equipment and structures:
_____   (1)   Deadend structure
_____   (2)   Breakers
_____   (3)   Switches
_____   (4)   Control building
_____   (5)   Instrument transformers
_____   (6)   Power transformer
_____   (7)   Switchgear
_____   (8)   Reactors
_____   (9)   Bus supports
_____   (10) Static masts
_____   (11) Capacitors
_____   (12) Surge arresters
_____   (13) Cable trench and designated drive paths
        d.   Bus and conductor:
_____   (1)   End bells
_____   (2)   Grounding studs
_____   (3)   Bus A-frame connection
_____   (4)   Jumper connections

_____   (5)   Strain bus

_____   (6)   Bus cutting schedule

_____   e.   Phasing (transmission line phases and bus phases)

_____   f.   Transmission line voltage and name designation

_____   g.   Section reference callouts

_____   h.   Detail reference callouts

_____   i.   Dimensions (fence to major equipment if dimensions do not show up on section drawings)

_____   j.   Future equipment

_____   k.   Notes

_____   l.   Baseline

       2.   Substation Sections and Details:

_____   a.   Bill of Material callouts (if typical is used, it is only for the section in question)

_____   b.   Dimensions (centerline of equipment)

_____   c.   Bottom of baseplate callout (each section)

_____   d.   Conductor and static wire takeoff heights, stranding, and maximum allowable tensions

           e.   Bus support type callout (may be shown on plan):

_____   (1)   Slip

_____   (2)   Fixed

_____   (3)   Expansion

_____   f.   Detail reference callouts

           g.   Bus and conductor:

_____   (1)   End bells

_____   (2)   Bus A-frame connections

_____   (3)   Grounding studs

_____   (4)   Jumper connections

_____   h.   Disconnect switches and switch operators

_____   i.   Area lighting

           j.   Notes:

_____   (1)   Reference assemblies

_____   (2)   Reference grounding details

_____   k.   Transmission line voltage, name designation, conductor, and stranding

_____   l.   Phasing

_____   m.   Equipment elevation differences to bottom of baseplate; elevation differences are noted if leveling nuts are used on some equipment

_____   n.   Elevation breaks in bus

_____   o.   Junction boxes/fuse boxes

_____   p.   Welding outlet locations

_____   q.   Telephone location

       3.   Substation Details:

           a.   Bill of material callouts

_____   b.   Reference notes to other details

H.   FOUNDATION PLAN AND DETAILS

Include the "General - for All Drawings" items.

       1.   Foundation Plan:

_____   a. Foundation key
_____   b. T.O.C. elevations
_____   c. Baselines
_____   d. Monuments with coordinates and elevations
_____   e. Buried facilities
_____   f. Fence
      g. Foundations:
_____   (1) Equipment
_____   (2) Deadend structures
_____   (3) Static masts (if any)
_____   (4) Control building
_____   (5) Cable trench
_____   (6) Oil containment system
      h. Dimensions - to centerline of all foundations, unless noted otherwise (should match with centerlines on foundation details, other dimensions as needed for clarification):
_____   (1) Cable trench
_____   (2) Centerline of drilled shafts
_____   (3) Corner of large foundations
_____   i. Manholes and handholes
      2. Foundation Details:
_____   a. Drilled shaft schedule
_____   b. Anchor bolt detail
_____   c. North arrow on Plan Views (reference to grid, true, or magnetic north).
_____   d. Anchor bolt locations
_____   e. Miscellaneous foundations
_____   f. Control building foundations

I.   STRUCTURE PLAN AND DETAILS

Include the "General - for All Drawings" items.
      1. Structure Plan:
         NOTE: On most substations it is sufficient to incorporate Structure Plan design with the Substation Plan drawing. Therefore a separate Structure Plan drawing is not required. For more complex substations, a Structure Plan may be required.
_____   a. Loading table
_____   b. Baselines
_____   c. Monuments with coordinates and elevations
_____   d. Fence
_____   e. Dimensions - to centerlines of all structures, unless noted otherwise (should match with centerlines on structure details, other dimensions as needed for clarification).
      f. Notes:
_____   (1) Definition of terms
_____   (2) Definition of symbols
      2. Structure Details:
_____   a. Loading table.
      b. Notes:
_____   (1) Definition of terms

_____   (2) Definition of symbols

J.   GROUNDING PLAN & DETAILS

Include the "General - for All Drawings" items.

        1. Grounding Plan:
_____   a. Baseline
_____   b. Dimension ground grid - if necessary
_____   c. Reference grounding details
_____   d. Cable trench ground
_____   e. Fence ground
_____   f. Switch operator mat
_____   g. Riser locations
_____   h. Bill of material for different size conductor
_____   i. Designation symbols per legend
        2. Grounding Details:
_____   a. Reference notes to other details
_____   b. Typical equipment grounding
_____   c. Typical structure grounding
_____   d. Typical power transformer grounding
_____   e. Typical switch grounding
_____   f. Typical fence and gate grounding
_____   g. Any specific required grounding

K.   RACEWAY PLAN AND DETAILS

Include the "General - for All Drawings" items.

        1. Raceway Plan:
_____   a. Baseline
_____   b. Raceway schedule (may be a separate database list)
_____   c. Conduit and direct-buried cable with approximate routing
_____   d. Conduit and direct-buried cable designations
_____   e. Cable trench
_____   f. Yard lighting symbols
_____   g. Yard receptacles
_____   h. Detail references
_____   i. Major equipment identifications
_____   j. Manholes and handholes
        2. Raceway Details:
_____   a. Reference notes to other details
_____   b. Conduit installation to equipment
_____   c. Control and lighting cable installation to equipment
_____   d. Major equipment identifications
_____   e. Cable trench details

L.   DUCT BANK AND HIGH-VOLTAGE CABLE PLAN AND DETAILS

Include the "General - for All Drawings" items.

        1. Duct Bank and High-Voltage Cable Plan and Profiles:

a. Duct bank curve data table:
_____   (1) Delta
_____   (2) Radius
_____   (3) Length
_____   (4) Tangent
_____ b. Stationing
_____ c. Northing and easting for beginning and end of duct bank
_____ d. Duct bank bearing and identification
_____ e. Finished grade and existing grade
2. Duct Bank and High-Voltage Cable Horizontal and Vertical Profiles, Sections, and Details:
_____ a. Reference notes to other details
_____ b. Duct size, quantity, and arrangement
_____ c. Reinforcing steel
_____ d. Depth, finished grade, backfill, and clearances

M.   CONTROL BUILDING PLANS, SECTIONS, AND DETAILS

Include the "General - for All Drawings" items.
1. Control Building Electrical Plan and Sections:
a. Equipment Plan:
_____   (1) Panel boards
_____   (2) Batteries
_____   (3) Battery charger
_____   (4) AC/DC power panels
_____   (5) Eye wash
_____   (6) Table & chair
_____   (7) Fuse boxes
_____   (8) Fire extinguisher
_____   (9) Exit sign
_____   (10) Dimensions
b. Equipment List:
_____   (1) Bill of material item number
_____   (2) Key number
_____   (3) Equipment description
c. Raceway Plan:
_____   (1) Equipment
_____   (2) Conduit
_____   (3) Raceway callouts
                 (4) Cable tray (if required):
                     (a) Tray key:
_____   [1] Key
_____   [2] Description
_____   [3] Size
_____   (5) Building cable trench (if required)
_____   (6) Raceway number
_____   (7) Raceway size
_____   (8) Circuit numbers (per Circuit Schedule) of each raceway
d. Lighting and grounding plan:

_____	(1) Lights (with correct legend symbol)
_____	(2) Exit sign location
_____	(3) Switches (location and type)
_____	(4) Receptacles
_____	(5) Circuit designations
_____	(6) Ground conductor locations
_____	(7) Ground connections
_____	(8) Equipment
_____	(9) Cable tray (if required)
	2. Control Building Mechanical (HVAC) Plan and Sections:
_____	a. Design and detailing may be done by mechanical discipline.
	3. Control Building Architectural Plan and Sections:
_____	a. Design and detailing may be done by architectural discipline.

N.   SUBSTATION BILL OF MATERIALS

(May be in database format.)

O.   RELAY CONTROL PANEL (SWITCHBOARD) LAYOUTS AND WIRING DIAGRAMS

Include the "General - for All Drawings" items.

	1. Layouts:
	a. Front view:
_____	(1) Panel designation
_____	(2) Mimic bus
_____	(3) Relays
_____	(4) Future relays
_____	(5) Control switches
_____	(6) Test switches
_____	(7) Panel dimensions
_____	(8) Future panels
	b. Rear view:
_____	(1) Relays
_____	(2) Future relays
_____	(3) Panel designation
_____	c. Nameplate schedule
_____	d. Relay Bill of Material
	2. Wiring Diagrams:
_____	a. Schematic reference
_____	b. Notes:
_____	(1) Definition of terms
_____	(2) Definition of symbols not shown on Legend sheet
_____	c. Device Internal Diagrams (may be a separate drawing)
_____	d. Bill of Material (may be a separate database)
_____	e. Device graphic showing terminals; device located on Wiring Diagram in general proximity of device location as installed on Layout
_____	f. Device Designation and Wiring Termination list adjacent to each device graphic

Example: **UA**
               1 - CA1
               2 - BD7
               L1 - UA2
               L2 - UA4

_____   g.   Terminal blocks with external cable and panel-to-panel circuit connections

P.   THREE-LINE DIAGRAMS, AC AND DC SCHEMATICS

Include the "General - for All Drawings" items.

　　　　　　　　　　　1.   Three-Line Diagrams
　　　　　　　　　　　　　　a.   Power Three-Line:
_____   　　　　(1)   Three phases
_____   　　　　(2)   Physically oriented
_____   　　　　(3)   Phasing
　　　　　　　　　　　　　　b.   PCBs:
_____   　　　　(1)   Bushing pole location and number
_____   　　　　(2)   Control cabinet
_____   　　　　(3)   Breaker number
　　　　　　　　　　　　　　c.   Disconnect switches:
_____   　　　　(1)   Group-operated/single phase
_____   　　　　(2)   Switch number
　　　　　　　　　　　　　　d.   Surge arresters:
_____   　　　　(1)   Quantity
_____   　　　　(2)   Voltage rating
_____   　　　　e.   Line designations
_____   　　　　f.   Line voltage
　　　　　　　　　　　　　　g.   CCVTs, CVTs, and PTs:
_____   　　　　(1)   Capacitors
_____   　　　　(2)   Drain coil
_____   　　　　(3)   Primary winding
_____   　　　　(4)   Secondary winding
_____   　　　　(5)   Heaters
_____   　　　　(6)   Secondary terminal block designations
_____   　　　　(7)   Carrier taps, if applicable
_____   　　　　(8)   LTU
_____   　　　　(9)   Phase identification
　　　　　　　　　　　　　　h.   Current transformers:
_____   　　　　(1)   Correct orientation as one-line diagrams
_____   　　　　(2)   Multi ratio vs. single ratio
_____   　　　　(3)   Polarity marks
_____   　　　　(4)   Ratio combinations for dual rated CTs
_____   　　　　(5)   Maximum ratio for multiratio CTs
_____   　　　　(6)   Connected ratio for multiratio CTs
_____   　　　　(7)   External terminals connected to external circuits

_____ (8) Jumpers
_____ (9) Grounds if applicable
      i.   Circuit designations:
_____ (1) Each circuit identified per circuit schedule designation
_____ (2) Terminal conductors shown with color coding
_____ (3) Spare conductors indicated
_____ (4) Shield tape or ground indicated
_____ (5) Circuit grounds indicated, if applicable
      j.   Power fuses:
_____ (1) Continuous current rating
      k.   Transformers:
_____ (1) Surge arresters
_____ (2) Bushing identification
_____ (3) Phasing
_____ (4) LTC
_____ (5) NLTC
_____ (6) Winding connections
_____ (7) Neutral
_____ (8) Transformer identification
_____ (9) Voltage ratings
_____ (10) MVA ratings
_____ (11) Cooling ratings
_____ (12) Temperature ratings
      l.   Major equipment:
_____ (1) Power ratings
_____ (2) Voltage ratings
_____ (3) Current ratings
_____ (4) Identification
      m. Miscellaneous:
_____ (1) Equipment/cabinet enclosures
_____ (2) Notes as applicable for clarification

2. AC Schematics
      a.   Current circuits for power circuit breakers, transformers and generators, and circuit switches and motor-operated disconnect switches:
          (1) Relay and meter current coils, and polarizing, neutral protection, and differential protection circuits:
             (a) Circuit designations:
_____ (1) Each circuit identified per circuit schedule designation
_____ (2) Terminal conductors shown with color coding
_____ (3) Spare conductors indicated
_____ (4) Shield tape or ground indicated
_____ (5) Circuit grounds indicated, if applicable
_____ (b) Location in circuit and proper orientation
_____ (c) Polarity (if applicable)
             (d) Phase:
_____ (1) Proper orientation
_____ (2) Terminal and connection points
_____ (e) Device connections and terminals
_____ (f) Current switches normal position: grounded, shared, open, or closed

_____   (g) Circuit ground located at device or at panel
                    (h) Miscellaneous current devices:
_____   (1) Fault recorders
_____   (2) Sequence of events recorders
                    (i) LTC current circuits:
_____   (1) Vacuum interrupters

    b. Potential circuits for power circuit breakers, transformers and generators, and circuit switches and motor-operated disconnect switches:
      (1) Relay and meter voltage coils and polarizing, synchronizing, and underfrequency load-shedding circuits:
        (a) Circuit designations:
_____   (1) Each circuit identified per circuit schedule designation
_____   (2) Terminal conductors shown with color coding
_____   (3) Spare conductors indicated
_____   (4) Shield tape or ground indicated
_____   (5) Circuit grounds indicated, if applicable
_____   (b) Location in circuit and proper orientation
_____   (c) Polarity (if applicable)
_____   (d) Phase
_____   (e) Device connection and terminal points
_____   (f) Voltage switches normal position: grounded, shorted, open, or closed
_____   (g) Circuit ground located at device or at panel
        (h) Miscellaneous voltage devices:
_____   (1) Fault recorders
_____   (2) Sequence of events recorders
_____   (3) Carrier blocking circuits
           (4) Auxiliaries:
_____   (a) Motors
_____   (b) Heaters
_____   (c) Lights
_____   (d) Miscellaneous
_____   (i) LTC circuits and controls

  3. DC Schematics:
    a. Circuit designations:
_____   (1) Each circuit identified per circuit schedule designation
_____   (2) Terminal conductors shown with color coding
_____   (3) Spare conductors indicated
_____   (4) Shield tape or ground indicated
_____   (5) Circuit grounds indicated, if applicable
    b. Relay trip and protection circuits:
      (1) Power circuit breakers:
        (a) Trip circuits:
          (1) Protective relay circuits:
_____   (a) Internal coils and contacts
_____   (b) Target coils and contacts
_____   (c) MOVs and transistors
_____   (d) Diodes and rectifiers
_____   (e) Resistors and capacitors
_____   (f) Relay taps and jumpers
         (2) Auxiliary relays:

_____   (a) Coils
_____   (b) Contacts
_____   (c) Miscellaneous devices
_____   (d) Spare device contacts
          (3) Trip-blocking contacts:
_____   (a) Control switch contacts
_____   (b) Blocking relay coils and contacts
_____   (4) SCADA control contacts
          (5) Contact callout tables:
_____   (a) Relay contacts
_____   (b) Switch contacts
          (6) Switch nameplates (escutcheons):
_____   (a) Positions
        (b) Close circuits:
          (1) Carrier start/stop circuits:
_____   (a) Relay terminals and connections.
          (b) Wire and device labels:
_____   [1] Transmit
_____   [2] Receive
          (2) Close block circuits:
_____   (a) Relay coils and contacts
_____   (b) Switch contacts
          (3) Reclosing relay:
_____   (a) Coils
          (b) Contacts:
_____   [1] Relays
_____   [2] Switches
_____   (4) SCADA control contacts
        (c) Auxiliary circuits:
_____   (1) Motors
_____   (2) Alarm points
_____   (3) Miscellaneous
        (d) Breaker Failure Relaying:
          (1) Relays:
_____   (a) Internal coils and contacts
_____   (b) Target coils and contacts
_____   (c) MOVs and transistors
_____   (d) Diodes and rectifiers
_____   (e) Resistors and capacitors
_____   (f) Relay taps and jumpers
_____   (2) Initiate contacts
_____   (3) Contact callout tables
      (2) Transformers and generators:
        (a) Trip schemes:
          (1) Differential circuits for power transformer, generator and bus:
          (a) Protective relay circuits:
_____   [1] Internal coils and contacts
_____   [2] Target coils and contacts
_____   [3] MOVs and transistors

_____   [4] Diodes and rectifiers
_____   [5] Resistors and capacitors
_____   [6] Relay taps and jumpers
_____   [7] Transformers and power supplies
             (b) Trip contacts:
_____   [1] Contact callout tables
             (c) Auxiliary relays:
_____   [1] References to breakers tripped and/or devices operated
_____   [2] Internal relay circuits as necessary
_____   (d) Relay terminals and connections
         (2) Sudden pressure (transformer):
             (a) Protective relay circuits:
                 [1] Internal coils and contacts
_____   [2] Target coils and contacts
_____   [3] MOVs and transistors
_____   [4] Diodes and rectifiers
_____   [5] Resistors and capacitors
_____   [6] Relay taps and jumpers
_____   [7] Transformers and power supplies
_____   (b) Sudden pressure switch
         (3) Neutral, highside, and remote trip schemes:
             (a) Protective relay circuits:
                 [1] Internal coils and contacts
_____   [2] Target coils and contacts
_____   [3] MOVs and transistors
_____   [4] Diodes and rectifiers
_____   [5] Resistors and capacitors
_____   [6] Relay taps and jumpers
_____   [7] Transformers and power supplies
             (b) Trip contacts:
_____   [1] Contact callout tables
             (c) Auxiliary relays:
_____   [1] References to breakers tripped and/or devices operated
_____   [2] Internal relay circuits as necessary
_____   (d) Relay terminals and connections
      (b) Alarm circuits:
         (1) Relays:
             (a) Coils
_____   (b) Contacts
_____   (2) Alarm cutout or reset switches
      (3) Circuit switchers and motor-operated disconnect switches:
         (a) Trip circuit:
             (1) Protective relay circuits:
                 (a) Internal coils and contacts
_____   (b) Target coils and contacts
_____   (c) MOV's and transistors
_____   (d) Diodes and rectifiers
_____   (e) Resistors and capacitors
_____   (f) Relay taps and jumpers.
             (2) Auxiliary relays:

_____   (a) Coils
_____   (b) Contacts
_____   (c) Miscellaneous devices
_____   (d) Spare device contacts
         (3) Trip-blocking contacts:
_____   (a) Control switch contacts
_____   (b) Blocking relay coils and contacts
_____   (4) SCADA control contacts
         (5) Contact callout tables:
_____   (a) Relay contacts
_____   (b) Switch contacts
         (6) Switch nameplates (escutcheons):
_____   (a) Positions
         (b) Close circuits:
_____   (1) Relay terminals and connections
         (2) Close block circuits:
_____   (a) Relay coils and contacts
_____   (b) Switch contacts
_____   (3) SCADA control contacts
         (c) Auxiliary circuits:
_____   (1) Motors
_____   (2) Alarm points
_____   (3) Miscellaneous
         4. SCADA and/or Alarm Schematics
         a. SCADA points:
         (1) Control
_____   (2) Indication
_____   (3) Metering
         b. Annunciator(s):
_____   (1) Contacts and terminals
_____   (2) Auxiliary equipment and accessories
_____   c. Miscellaneous alarms
         d. Circuit designations:
_____   (1) Each circuit identified per circuit schedule designation
_____   (2) Terminal conductors shown with color coding
_____   (3) Spare conductors indicated
_____   (4) Shield tape or ground indicated
_____   (5) circuit grounds indicated, if applicable
_____   e. SCADA point list

Q.   MISCELLANEOUS EQUIPMENT YARD EXTERNAL CONNECTION DIAGRAMS

Include the "General - for All Drawings" items.
_____   1. Schematic Reference
         2. Notes:
_____   a. Definition of terms
_____   b. Definition of symbols not shown on Legend sheet
_____   3. Device Graphic Showing Terminals and Terminal Blocks

NOTE: In general, the internal detail is not required or is shown on device manufacturer's diagrams. The external cable connection is the important data to be conveyed.

_____   4.   Terminal blocks with jumpers and external cable connections.

APPENDIX B
U.S. DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE
SUBSTATION DESIGN SUMMARY

INTRODUCTION

1.1 GENERAL

1. This summary provides basic information on substation requirements and design.
2. The summary will be updated as the project progresses from initial design to in-service status. In its final form it will be, with supporting and reference documents, a complete record of the substation.

1.2 BASIC IDENTIFICATION DATA

1. Substation Name _____
2. Cooperative's Designation and Name _____

3. Location _____
4. Summary Prepared by _____
   Date_____
   Revision "A" Prepared by _____
   Date _____
   (As many listings as necessary. Whenever a revision is made, a notation should be entered in the left-hand margin adjacent to the item revised.)

1.3 SCHEDULE

	Proposed or Record Date
1.3.1 Pre-Design (identify documentation of each item for record)	_____
a. Environmental Assessment or Environmental Report	_____
b. Site purchase and title clearance	_____
c. Topographical survey	_____
d. Ambient noise level survey	_____
e. Surrounding land use survey	_____
f. Soil borings	_____
g. Soil resistivity measurements	_____

1.3.2 Design

a. One-line diagram and general layout for cooperative's approval _____
b. Detailed design for cooperative's approval (list individual areas such as foundations, structures, electrical below grade, electrical above grade, and protective relaying if separate submittals are required) _____
c. Design complete _____

1.3.3 Procurement (itemize as listed below for each set of equipment, material, and hardware)

a. Specification for cooperative's approval _____
b. Bid invitation _____
c. Pre-bid meeting with vendors or contractors (sometimes advantageous for major equipment or construction) _____

d. Bids received _____
e. Bid opening (usually construction only) _____
f. Evaluation of bids _____
g. Pre-award meeting (sometimes advantageous with major equipment
     or construction) _____
h. Contract award _____
i. Delivery (equipment, material, or hardware) _____

1.3.4 Construction

a. Begin construction _____
b. Complete site grading _____
c. Complete drainage _____
d. Complete roadways _____
e. Complete fence _____
f. Begin foundations, conduit, and grounding _____
g. Complete below grade _____
h. Begin above grade _____
i. Complete outdoor yard _____
j. Complete control house _____
k. Complete testing (list documents) _____
l. Complete inspection (list documents) _____
m. In service _____

1.4 PERMITS AND LICENSES

List all permits and licenses that will be required prior to and during construction. _____

_____

_____

_____

1.5 REFERENCES

1. Power requirements study (identify) _____
2. Two-Year Work Plan (identify) _____
3. Conceptual one-line diagram (identify) _____

2   DESIGN CONSIDERATIONS

2.1 INITIAL AND ULTIMATE REQUIREMENTS

1. Nominal Operating Voltages (itemize as listed below for each voltage):
    a. Voltage _____ kV
    b. Design BIL_____ kV
    c. Connection (delta or wye) _____
    d. Phase rotation _____
    e. Phase displacement with respect to other voltages (leads or lags) _____ kV by
         _____

2.   Capacity:
  a.   Voltage Transformations (itemize as listed below for each transformation):
    (1)   High Voltage/Low Voltage _____/_____ kV:
        (a) Initial Capacity _____ MVA
        (b) Ultimate Capacity _____ MVA
    (2)   High Voltage/Low Voltage _____/_____ kV:
        (a) Initial Capacity _____ MVA
        (b) Ultimate Capacity _____ MVA
  b.   Circuit Connections (itemize as listed below for each connection):
    (1)   Voltage _____ kV
        (a) Initial Quantity _____
        (b) Final Quantity _____
    (2)   Voltage _____ kV
        (a) Initial Quantity _____
        (b) Final Quantity _____
  c.   Bus Configurations (itemize as listed below for each bus):
    (1)   Nominal Bus Voltage:
        (a) Initial Configuration _____
        (b) Ultimate Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-and-a-half, double breaker-double bus) _____
    (2)   Nominal Bus Voltage:
        (a) Initial Configuration _____
        (b) Ultimate Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-and-a-half, double breaker-double bus) _____
  d.   Current-Carrying Requirements (itemize as listed below for each bus and circuit connection):
    (1)   Bus or circuit connection description _____
    (2)   Nominal voltage _____ kV
    (3)   Ampacity:
        (a) Continuous _____ amperes
        (b) 24-hour temporary _____ amperes
  e.   Ultimate Power Supply Fault Conditions:
    (1)   Three-phase fault _____ amperes
    (2)   Phase-to-phase fault _____ amperes
    (3)   Phase-to-ground fault _____ amperes
  f.   Maximum Permissible Fault Clearing Time _____ seconds

2.2 SITE

State any unusual constraints imposed on the design because of site characteristics.

2.3 ENVIRONMENTAL

1.   State that design is in accordance with Environmental Assessment (identify) or Environmental Report (identify).
2.   Describe property and adjacent property including existing land use.
3.   State any other uses in addition to substation (such as storage).
4.   Describe, in general, any design measures taken to enhance appearance.
5.   State the necessity for any unusual cost items related to public safety.

6. State the rationale for noise contribution.
7. State the expected electrostatic and electromagnetic effects.
8. State the rationale for effluent design. Recommend that a design be made for a plan of action to prevent pollution if this is so indicated.

2.3.1 Weather

a. State any unusually severe possible local conditions that the substation is not designed to withstand.
b. State what design measures have been taken with respect to any special local condition.

2.3.2 Temperatures

a. Average annual temperature:
   (1) Maximum _____ $^{\circ}$C (_____ $^{\circ}$F)
   (2) Minimum _____ $^{\circ}$C (_____ $^{\circ}$F)
b. Highest recorded temperature _____ $^{\circ}$C (_____ $^{\circ}$F)
c. Lowest recorded temperature _____ $^{\circ}$C (_____ $^{\circ}$F)

2.3.3 Wind and Ice Loading (itemize as listed below for line support structures, equipment support structures, and conductors)

a. Wind:
   1. Velocity _____ km/hr (_____ mph)
   2. Safety factor _____
   3. Gusts _____ km/hr (_____ mph)
   4. Safety factor _____
b. Ice:
   1. Thickness _____ cm (_____ in.)
   2. Safety factor _____

2.3.4 Precipitation

a. Design rainfall:
   1. Amount _____ cm/hr (_____ in./hr)
   2. Period _____ hours
   3. Frequency of storm occurrence _____
b. Design snowfall:
   1. Maximum drift depth _____ m (_____ ft)
c. Electrical storms:
   1. Isokeraunic level _____ thunderstorm days per year
d. Humidity:
   State design measures.

2.3.5 Altitude Above Mean Sea Level _____ m (_____ ft)

2.3.6 Seismic Risk Zone _____

2.3.7 Wildlife Protection
State any unusual measures required.

2.3.8 Airborne Foreign Material Protection
State materials protecting against.

3   DOCUMENTS

3.1   <u>AUTHORIZING DOCUMENT FOR DESIGN</u>

3.2   <u>DISTRIBUTION OF DOCUMENTS</u> Itemize as listed below for each document and recipient.

(See Table 3-2 for Typical Document Distribution List.)

1. Document Description _____
___ _____
2. Name and Address of Recipient _____
___ _____
___ _____
3. Number of Copies Spec _____ , Full-Size Drawings _____ , Half-Size Drawings _____

3.3   <u>RUS PROCEDURES</u> (To be checked with RUS)

1. Name and Address of RUS General Field Representative _____
_____
_____

Table 3-2: Typical Document Distribution List

Distribution List	Cooperative's Environmental Report	Feasibility Studies	Technical Studies	Procedures Manual	Design Manual	Equipment Contract	Materials Contract	Construction Contract	Permits	Drawings
Owner										
General Manager	X	X		X					*	
Chief Engineer	X	X	X	X	X	X	X	X	X	*
Legal	X	X		X		X	X	X	X	
Design Engineer		X	X	X	X	X	X	X	X	X
Owner's Field Representative				X	X	X	X	X	X	X
File	X	X	X	X	X	X	X	X	X	X
Engineer				X						
Project Manager	X	X		X	X	X	X	X	*	*
Design Engineer	X	X	X	X	X	X	X	X	X	X
File	X	X	X	X	X	X	X	X	X	X
Resident Manager				X	X	X	X	X	X	X
Inspector				X		X	X	X		X
Contractors										
C1						*	*	*	*	*
C2						*	*	*	*	*
C3						*	*	*	*	*
C4						*	*	*	*	*
C5						*	*	*	*	*
Approving Agencies										
RUS	X	X							*	X
County/City Engineer			*			*	*	*	*	*
Interconnecting Utility		X	X			*	*	*	*	*
Property Holder									*	*

* As Required.

3.4 PROCUREMENT

1. Major Equipment (itemize as listed below for each major piece of equipment, contract, or P.O):
    a. Description of Equipment _____
    b. Name and Address of Manufacturer _____
    c. Contract number _____
    d. Purchase order number _____

2. Construction Contracts (itemize as listed below for each contract):

    a. Description of contract _____

    b. Name and address of contractor

    c. Contract number _____
    d. Purchase order number _____

3. Equipment, Materials, and Hardware (itemize as listed below for each item, contract, or P.O):

    a. Description of item _____

    b. Name and address of manufacturer

    c. Purchase order number _____

3.5 DRAWING LIST OR DRAWING LIST NUMBER

Provide list of drawings or drawing list number. Indicate contracts, purchase orders, etc., each drawing is part of or referenced.

3.6 STUDIES

Describe the studies that are required.

4 PHYSICAL LAYOUT

4.1 SUBSTATION TYPE (distribution, transmission, switching)

4.2 TYPE OF DESIGN (cooperative's standard, packaged, custom)

4.3 <u>**CIRCUIT CONNECTIONS**</u> Itemize as listed below for each connection.

1. Overhead Circuits:
   a. Nominal voltage _____ kV
   b. Quantity _____
   c. Conductor size, type, and material _____
   d. Pull-off elevation _____ m (_____ ft)
   e. Maximum tension _____ N (_____ lb)
      (1) Temperature _____ ^{o}C (_____ ^{o}F)
      (2) Ice thickness _____ cm (_____ in.)
      (3) Wind velocity _____ km/hr (_____ mph)
   f. Shield wires:
      (1) Quantity of shield wires per connection _____
      (2) Wire size, type, and material _____
      (3) Pull-off elevation _____ m (_____ ft)
      (4) Maximum tension (at same conditions as phase conductors) _____
          N (_____ lb)
2. Underground Circuits:
   a. Nominal voltage _____ kV
   b. Quantity _____
   c. Conductor size, type, material, and insulation _____

4.4 <u>**DISTRIBUTION SUBSTATIONS**</u>

1. Provisions for Mobile Transformer (yes or no) _____
2. Provisions for Mobile Substation (yes or no) _____
3. Provisions for Future Addition of (describe) _____

4. Provisions for Source Voltage Change (yes or no) _____
   a. Initial voltage _____ kV
   b. Ultimate voltage _____ kV
   c. Change of (describe) _____
5. Provisions for Load Voltage Change (yes or no) _____
   a. Initial voltage _____ kV
   b. Ultimate voltage _____ kV
   c. Change of (describe) _____

4.5 <u>**TRANSMISSION SUBSTATIONS**</u> (only)

1. Provisions for Future Addition of (describe) _____

2. Provisions for Source Voltage Change (yes or no) _____
   a. Initial voltage _____ kV
   b. Ultimate voltage _____ kV
   c. Change of (describe) _____

3. Provisions for Load Voltage Change (yes or no) _____
   a. Initial voltage _____ kV

      b.   Ultimate voltage _____ kV

      c.   Change of (describe) _____

_____

4.6 <u>SWITCHING SUBSTATIONS</u> (only)

1. Provisions for Future Addition of (describe) _____

_____

2.   Provisions for Voltage Change (yes or no) _____

      a.   Initial voltage _____ kV

      b.   Ultimate voltage _____ kV

      c.   Change of (describe) _____

_____

4.7 <u>BUS CONFIGURATION</u> Itemize as listed below for each bus.

1. Initial:
      a.   Nominal bus voltage _____ kV
      b.   Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-
          and-a-half, double breaker-double bus) _____

2. Ultimate (if different from initial):
      a.   Nominal bus voltage _____ kV
      <u>b.</u>   Configuration (describe) _____

_____

4.8 <u>DIRECT STROKE SHIELDING</u>

1. Shielding Measures (rods, wires, masts) (describe)

_____

2. Shielding Angles:
      a.   Angle from vertical for single rod, wire, or mast _____ $^{\circ}$
      b.   Angle from vertical for adjacent rods, wires, or masts _____ $^{\circ}$

4.9 <u>INSULATORS</u> Itemize as listed below for each voltage.

1. Apparatus Insulators:
      a.   Nominal voltage _____ kV
      b.   Type (cap and pin or post) _____
      c.   BIL _____ kV
      d.   Color _____
      e.   Cantilever strength _____ N (_____ lb)
      f.   NEMA TR No. (or other description) _____

_____

2. Suspension Insulators:
      a.   Nominal voltage _____ kV
      b.   Quantity per string _____
      c.   Color _____
      d.   M-E strength _____ N (_____ lb)
      e.   ANSI Class (or other description) _____

4.10 **ELECTRICAL CLEARANCES** Itemize as listed below for each voltage.

1. Nominal voltage _____ kV

		Rigid Conductors	Non-Rigid Conductors
2.	Minimum Metal-to-Metal	_____ cm (_____ in.)	_____ cm (_____ in.)
3.	Minimum Phase to Grounded Parts	_____ cm (_____ in.)	_____ cm (_____ in.)
4.	Minimum Phase to Substation Grade	_____ m (_____ ft)	_____ m (_____ ft)
5.	Minimum Phase to Substation Roadway	_____ m (_____ ft)	_____ m (_____ ft)
6.	Centerline-to-Centerline Phase Spacing	_____ m (_____ ft)	_____ m (_____ ft)

4.11 **BUS AND ELECTRICAL CONNECTIONS** Itemize as listed below for each case.

1. Nominal Voltage _____ kV
2. Type of Connection (describe) _____
3. Rigid Conductors (clamp, bolted, compression, welded) _____
4. Non-Rigid Conductors (clamp, compression, welded) _____
5. Fasteners (describe) _____

4.12 **RIGID BUSES** (itemize as listed below for each bus)

1. Conductor Size, Type, and Material _____
2. Design Short Circuit Current (three-phase symmetrical) _____ rms amperes
3. Wind and Ice Loading
4. Support Insulator Spacing _____ m (_____ ft)
5. Factor of Safety for Support Insulators _____
6. Maximum Conductor Sag Without Ice _____
7. Maximum Conductor Sag With Ice _____
8. Measures for Prevention of Aeolian Vibration _____
9. Provisions for Conductor Expansion _____

4.13 **STRAIN BUSES** Itemize as listed below for each bus.

1. Conductor Size, Type, Stranding, and Material _____
2. Wind and Ice Loading
3. Span Length _____ m (_____ ft)
4. Factor of Safety for Suspension Insulators _____
5. Sag and Tension at Maximum Loading Conditions _____ m (_____ ft) sag at _____ N (_____ lb) tension
6. Sag and Tension at 25ºC (77ºF) _____ m (_____ ft) sag at _____ N (_____ lb) tension
7. Sag and Tension at 70ºC (167ºF) _____ m (_____ ft) sag at _____ N (_____ lb) tension

5   MAJOR EQUIPMENT

Itemize as listed below for each different component.

5.1   POWER TRANSFORMERS

1. Type (auto, multi-winding, 3-phase, 1-phase) _____
2. Quantity _____
3. Dielectric (oil, air, or gas) _____
4. Rating _____/ _____/ _____ MVA
5. Cooling (OA, OA/FA, OA/FA/FA, OA/FOA, OA/FA/FOA, OA/FOA/FOA) _____
6. Average Winding Temperature Rise (55ºC, 65ºC) _____
7. Primary Voltage _____ kV
    a. No-load taps _____
8. Secondary Voltage _____ kV
    a. No-load taps _____
9. Tertiary Voltage _____ kV
    a. No-load taps _____
10. Load-Tap-Changer (LTC):
    a. Percentage above and below nominal voltage _____
    b. Winding (primary or secondary) _____
11. BIL:
    a. Primary winding _____ kV
    b. Secondary winding _____ kV
    c. Tertiary winding _____ kV

5.2   POWER CIRCUIT BREAKERS

1. Type (dead tank or live tank) _____
2. Quantity_____
3. Interrupting Medium (oil, gas (SF_6), vacuum)_____
4. Nominal Voltage_____ kV
5. Maximum Voltage _____ kV
6. Rated Voltage Range Factor (K)_____
7. Continuous Current _____ rms amperes
8. Short-Circuit Current at Rated Maximum Voltage _____ rms amperes
9. Maximum Symmetrical Interrupting Capability _____ rms amperes
10. 3-Second Short Time Current Capability _____ rms amperes
11. Closing and Latching Capability _____ rms amperes
12. Interrupting Time _____ cycles
13. Type of Operating Mechanism (solenoid, motor, pneumohydraulic, pneumatic, motor-charged spring, manual-charged spring, manual) _____
14. Control Power Voltage _____ VAC _____ VDC
15. Auxiliary Power Voltage _____ VAC

5.3   METAL-CLAD SWITCHGEAR

1. Nominal Voltage _____ kV

2. Indoor or Outdoor _____ , Sheltered Aisle_____
3. Switching Scheme (describe) _____
   _____
4. Continuous Current Bus _____ amperes, Feeders _____ amperes
5. Maximum RMS Momentary Current _____ kA, _____ MVA
6. Circuit Breaker Interrupting Capability _____ amperes
7. Circuit Exits Underground _____ , Overhead _____

5.4 SUBSTATION VOLTAGE REGULATORS

1. Type (step or induction, single- or three-phase) _____
2. Quantity _____
3. Nominal Voltage _____ kV
4. Rating _____ kVA
5. Percentage Regulation + _____%, – _____%

5.5 SHUNT CAPACITOR EQUIPMENT

1. Type (open rack or housed) _____
2. Quantity _____
3. Nominal Voltage _____ kV
4. Bank Rating _____ kVAR
5. Individual Units:
   a. Voltage _____ kV
   b. Rating _____ kVAR
6. Connection (delta, wye, grounded wye, double wye) _____

5.6 AIR SWITCHES

1. Type (disconnecting, grounding, horn-gap, interrupter, selector) _____
2. Quantity _____
3. Construction (vertical break, double break, tilting insulator, side break, center break, vertical reach) _____
4. Operating Mechanism (hook stick, manual mechanism, motor mechanism) _____
5. Poles (single or three) _____
6. Nominal Voltage _____ kV
7. Continuous Current _____ amperes
8. Momentary Current _____ amperes
9. Interrupting Current _____ amperes

5.7 SURGE ARRESTERS

1. Type (station, intermediate, distribution) _____
2. Quantity _____
3. Voltage Rating _____ kV-Duty Cycle, _____ kV MCOV
4. Nominal System Voltage _____ kV
5. System Grounded _____ , Ungrounded _____
6. For Protection of (describe) _____

5.8 <u>AUTOMATIC CIRCUIT RECLOSERS</u>

1. Quantity _____
2. Nominal Voltage _____ kV
3. Continuous Current _____ amperes
4. Interrupting Current _____ amperes
5. Single- or Three-Phase _____
6. Interrupting Medium (oil, vacuum, gas (SF_6)) _____
7. Control (Hydraulic or electronic) _____
8. Coil Tripping (series, non-series) _____
9. Closing (spring, solenoid, motor) _____ ___
10. Minimum Tripping Current _____ amperes
11. Operational Sequence to Lockout (1-A, 3-B) _____

5.9 <u>CURRENT TRANSFORMERS</u>

1. Type (bar, window, bushing, other) _____
2. Quantity _____
3. Nominal System Voltage _____ kV
4. BIL _____ kV
5. Rated Primary to Secondary Current Ratio(s)_____
6. Secondary Winding Configuration (single, dual, multi-ratio) _____
7. Accuracy (metering or relaying) _____
8. Accuracy Class at Standard Burdens _____
9. Continuous – Thermal – Current Rating Factor _____
10. Short-Time Mechanical and Thermal Current Ratings _____

5.10 <u>VOLTAGE TRANSFORMERS</u>

1. Type (cascade, grounded neutral, insulated neutral, single high-voltage line terminal, double high-voltage line terminal, etc.) _____
2. Quantity _____
3. Nominal System Voltage _____ kV
4. BIL _____ kV
5. Ratio(s) _____
6. Accuracy Class at Standard Burdens _____
7. Thermal Burden Rating _____ VA

5.11 <u>COUPLING CAPACITORS AND COUPLING CAPACITOR VOLTAGE TRANSFORMERS</u>

1. Type (CC or CCVT) _____
2. Quantity _____
3. Nominal System Voltage _____ kV
4. BIL _____ kV
5. Capacitance _____ pico farads
6. Carrier Accessories (yes or no) _____
7. Voltage transformer (yes or no) _____

    a.   Ratio(s) _____
    b.   Accuracy Class at Standard Burdens _____
    c.   Thermal Burden Rating _____

5.12 MOBILE UNITS

1. Type (transformer, substation) _____
2. Quantity _____
3. Primary Voltage _____ kV
4. Secondary Voltage _____ kV
5. Capacity _____ MVA
6. Accessories (list and describe) _____

_____

_____

6   SITE

6.1 GENERAL

1. Yard Type (flat, sloped, stepped) _____
2. Nominal Finished Grade Elevation(s) _____ m (_____ ft) with _____% slope
3. Topographical Drawing Reference _____
4. Soil Boring Reference _____

6.2 DRAINAGE

1. Type of System (surface or closed) _____
2. Design Basis (see Chapter 6, Section 6.4)
3. Time for Runoff from Remotest Part of Drainage Area _____ hours

6.3 EARTHWORK

1. Excess Top Soil _____ m^3 (_____ yd^3)
2. Fill Required _____ m^3 (_____ yd^3)
3. Earth to Be Moved Exclusive of Excess Top Soil _____ m^3 (_____ yd^3)

6.4 ROADS Itemize as listed below for each access road, interior road, and railroad.

1. Length _____ m (_____ ft)
2. Width _____ m (_____ ft)
3. Maximum Grade _____%
4. Minimum Inside Curve Radius _____ m (_____ ft)
5. Base Course _____
6. Wearing Course _____
7. Maximum Equipment Load _____ kg/axle (_____ lb/axle)

6.5 EROSION PROTECTION

State basic description.

6.6 YARD SURFACING MATERIAL

1. Material:
    a. Type _____
    b. Size _____
2. Material Placement:
    a. Area
    b. Layer depth _____ cm (_____ in.)

6.7 SECURITY FENCE

1. Height _____ m (_____ ft)
2. Fabric Gauge _____
3. Fabric Material _____
4. Gates (itemize as listed below for each size gate):
    a. Size _____ m (_____ ft)
    b. Quantity _____
5. Depth of Post Footing Holes _____ m (_____ ft)

7 STRUCTURES

7.1 LINE SUPPORT STRUCTURES

1. Material_____
2. Protective Coating or Treatment _____
3. Loading Criteria:
    a. Conductors _____ N (_____ lb) per phase
    b. Shield wires _____ N (_____ lb) per wire
    c. Equipment weight _____ kg (_____ lb)
    d. Wind and ice loads (see Sections 2.3.3)
    e. Seismic (describe) _____
        _____
4. Overload Factor _____
5. Unit Stress Limit _____
6. Deflection Limits _____
7. Fasteners (describe) _____
    _____

7.2 EQUIPMENT SUPPORT STRUCTURES

1. Material _____
2. Protective Coating or Treatment _____
3. Loading Criteria:
    a. Equipment weight _____ kg (_____ lb)

b.   Short circuit force _____ N/m (_____ lb/ft)
c.   Wind and ice loads (see Sections 2.3.3)
d.   Seismic (describe) _____

4.   Unit Stress Limit _____
5.   Deflection Limits _____
6.   Rigidity Considerations _____

7.   Fasteners (describe) _____

8   FOUNDATIONS

8.1   SOIL

1.   Type _____
2.   Allowable Soil Bearing Pressure _____ N/m^2 (_____ psf)
3.   Describe Other Soil Capability Limitations _____

4.   Depth Below Grade to Groundwater _____ m (_____ ft)

8.2   DESCRIPTION OF CONCRETE

1.   Type _____
2.   Minimum 28-Day Compressive Strength _____ N/cm^2 (_____ psi)
3.   Depth Below Grade to Withstand Frost _____ m (_____ ft)

8.3   DESCRIPTION OF REINFORCING BAR

Describe the reinforcing bar used in each type of foundation.

8.4   OIL POLLUTION ABATEMENT

Describe methods for oil pollution abatement.

8.5   FOUNDATION TYPES

Describe each type of foundation (drilled shaft, spread footing, slab) and its function.

9   GROUNDING

9.1   SOIL RESISTIVITY MEASUREMENTS

1.   Data from soil testing on (date) _____ .

9.1.1   Uniform Soil Assumption

1.   Mathematical average of the measured apparent resistivity data, ρ = _____ ohm-meter

9.2 AREA OF THE GROUND GRID

1. Describe geometric shape of ground grid including dimensions.
2. Calculated total ground grid area, $A = \underline{\hspace{1cm}}$ m^2

9.3 Ground Fault Current

9.3.1 Maximum Symmetrical rms Value of Zero Sequence Fault Current (single phase-to-ground), $I_o = \underline{\hspace{1cm}}$ Amps

9.3.2 Initial rms Symmetrical Ground Fault Current, $I_f = \underline{\hspace{1cm}}$ Amps

9.3.3 Symmetrical Grid Current, $I_g = \underline{\hspace{1cm}}$ Amps

9.3.4 Determined Split Factor:

1. Substation ground resistance, $R_g = \underline{\hspace{1cm}}$ ohms
2. Split Factor, $S_f =$

9.3.5 Determine Decrement Factor

1. Time duration of fault, $t_f = \underline{\hspace{1cm}}$ seconds
2. Dc offset, $T_a = \underline{\hspace{1cm}}$ seconds
3. Decrement factor, $D_f =$

9.3.6 Maximum Grid Current, $I_G = \underline{\hspace{1cm}}$ Amps

9.3.7 Asymmetrical Fault Current, $I_F = \underline{\hspace{1cm}}$ Amps

9.4 SELECTION OF CONDUCTOR MATERIAL

1. Material Cu $\underline{\hspace{2cm}}$ Other $\underline{\hspace{2cm}}$

9.4.1 Area of Conductor

1. Area of Conductor:
   a. Maingrid $A_{kcmil} = \underline{\hspace{2cm}}$ kcmil
   b. Perimeter $A_{kcmil} = \underline{\hspace{2cm}}$ kcmil
   c. Risers $A_{kcmil} = \underline{\hspace{2cm}}$ kcmil
2. Length of Conductor:
   a. Main grid $\underline{\hspace{2cm}}$
   b. Perimeter $\underline{\hspace{2cm}}$
   c. Risers $\underline{\hspace{2cm}}$

9.4.2 Ground Rods:

1. Diameter $\underline{\hspace{2cm}}$
2. Length $\underline{\hspace{2cm}}$

3. Quantity _____

9.5 SAFETY CONSIDERATIONS

9.5.1 Rms magnitude of the current through the body, $I_B =$ _____ Amps

9.6 TOLERABLE TOUCH AND STEP VOLTAGES

1. Maximum tolerable step voltages, $E_{step} =$ _____ volts
2. Maximum tolerable touch voltages, $E_{touch} =$ _____ volts

9.7 PROTECTIVE SURFACE MATERIAL AND REDUCTION FACTOR

1. Type of protective surface material _____
2. Resistivity of protective surface material, $\rho_s =$ _____ ohm-meter
3. Reflection factor, K= _____
4. Reduction factor, $C_s =$ _____

9.8 DESIGN OF A SUBSTATION GROUNDING SYSTEM

9.8.1 Grid Design _____

_____

9.8.2 Calculated Design Mesh Voltage

1. Calculate total length of grid conductor $L_R =$ _____ meter
2. Calculated total length ground rod $L_C =$ _____ meter
3. Calculated Design Mesh Voltage, $E_m =$ _____ volts

9.8.3 Calculated Design Step Voltage, $E_S =$ _____ volts

9.8.4 Ground Potential Rise, VGPR = _____ volts

10 INSULATED CABLES AND RACEWAYS

10.1 CABLES Itemize as listed below for each type of cable.

1. Type (control or power) _____
2. Voltage Rating _____ volts
3. Conductor Size, Type, and Material
4. Number of Conductors _____
5. Quantity _____ m (_____ ft)
6. Insulation:
    a. Type _____
    b. Thickness _____ mils
7. Jacket:
    a. Type _____
    b. Thickness over each conductor _____ mils
    c. Thickness over entire cable _____ mils

10.2 RACEWAYS Itemize as listed below for each type of raceway.

1. Conduit:
   a. Material _____
   b. Size _____ cm (_____ in.)
2. Duct Bank:
   a. Size
      (1) Width _____ m (_____ ft)
      (2) Depth _____ m (_____ ft)
      (3) Number of conduits:
          (a) Width _____
          (b) Depth _____
      (4) Size of conduits _____ cm (_____ in.)
3. Cable Trench
   a. Type (concrete block, cast-in-place concrete, or precast concrete)
   b. Width _____ cm (_____ in.)
   c. Depth _____ cm (_____ in.)

11 CORROSION

11.1 STATE RATIONALE FOR THE PROVISION (OR LACK) OF A CATHODIC PROTECTION SYSTEM

11.2 CATHODIC PROTECTION SYSTEM

1. Summary of Soil Resistivity Survey

   _____
   _____
   _____

2. Summary of pH Survey

   _____
   _____
   _____

3. Basic Description of Protection System

   _____
   _____
   _____

12 PROTECTIVE RELAYING

12.1 GENERAL PHILOSOPHY

State the general philosophy of the protective relaying systems: coordination required with other parts of the system, expected fault currents for various conditions, speed of interruption sought for various cases, etc.

12.2 <u>TRANSMISSION LINE PROTECTION</u> Itemize as listed below for each line.

1. Line Destination or Description _____
2. Nominal Voltage _____ kV
3. <u>3</u>. Protection Scheme (phase comparison, directional comparison, direct underreach, permissive underreach, permissive overreach, overcurrent; describe) _____
   _____
4. Automatic Reclosing (yes or no; describe) _____
5. Relays (list) _____
6. Communication Channel (Power Line Carrier, Microwave, Fiber Optic, Leased Line)
   _____

12.3 <u>TRANSFORMER AND REACTOR PROTECTION</u> Itemize as listed below for each transformer and reactor.

1. Transformer or Reactor Number or Description _____
2. Nominal Voltages (Primary/tertiary/secondary) _____ / _____ / _____ kV
3. <u>3</u>. Protection Scheme (differential, sudden pressure, directional phase distance, ground overcurrent; describe) _____
   _____
4. Relays (list) _____
   _____

12.4 <u>BUS PROTECTION</u> Itemize as listed below for each bus.

1. Bus Number or Description _____
2. Nominal Voltage _____ kV
3. Protection Scheme (current differential, voltage differential; describe) _____
   _____
4. Relays (list) _____
   _____

12.5 <u>BREAKER FAILURE PROTECTION</u>

1. Where applied (describe) _____
   _____
2. Relays (list) _____
   _____

12.6 <u>DISTRIBUTION LINE PROTECTION</u> Itemize as listed below for each line.

1. Line Destination or Description _____
2. Nominal Voltage _____ kV
3. Protection Scheme (overcurrent relaying, automatic circuit reclosers, sectionalizers, fuses; describe) _____
4. Relays and Equipment (list) _____

13   INSTRUMENTS, TRANSDUCERS, AND METERS

Describe metering systems and list equipment for each system.

14   SUBSTATION AUTOMATION

Define the application by completing the following information:

14.1   FUNCTIONS TO BE PERFORMED

Describe the functions to be performed:

   a.   Automatic control
   b.   Supervisory control
   c.   Monitoring
   d.   Human - machine

14.2   DEVELOP ARCHITECTURE PHILOSOPHY

Justify whether a proprietary or open system is needed.

14.3   ARCHITECTURE DEFINITION

   1.   Top layer—user interface where data and control prerogatives are presented to the end user.
   2.   Intermediate layer—implemented with discrete elements or subsystems.
   3.   Bottom layer—electrical power substation and field devices (transformers, breakers, switches, etc).

14.4   BASIC ELEMENTS

   1.   Will a local substation host processor be used (single or multiple computers)? Describe rationale.
   2.   Describe the type of redundancy that is needed for this application.
   3.   Describe any Intelligent Electronic Devices (IEDs) to be used:
       a.   Function
       b.   Communications medium
       c.   Protocols supported
       d.   Data acquisition method
   4.   Will a data concentrator be used? Describe its purpose and functions.
   5.   If a LAN is used, describe:
       a.   What access method will be used (CSMA/CD, token ring, token bus, or FDDI)? Develop rationale.
       b.   What is the expected load of the network?
       c.   Do any functions require a deterministic access method? Describe.
       d.   What is the desired data rate?
       e.   Define the physical locations of nodes or communicating devices.
       f.   Describe the physical media that will be used (coaxial cable, UTP, or optical fiber).
       g.   Describe any serial data interfaces to be used (RS-232, RE-422/423 or RS-485). Define type, location, and purpose.

6. What is the communications protocol(s) being utilized (IEC 970-5, DNP 3.0, MODBUS, MMS, ASCII, Landis & Gyr 8979, or other)?

15   AC AND DC AUXILIARY SYSTEMS

15.1   AC SYSTEM

1. Connected AC Load _____ kVA
2. Overall Demand Factor _____%
3. Auxiliary Transformer:
   a. Rating _____ kVA
   b. Voltage (primary/secondary) _____ / _____ kV
4. Normal Source (describe) _____

5. Alternative Source (describe) _____

6. Auxiliary System Voltage (480/277 volts, wye-connected, three-phase, four-wire; 208/120 volts, wye-connected, three-phase, four-wire; 240/120 volts, delta-connected, three-phase, four-wire; 240/120 volts, open delta-connected, three-phase, four-wire; 240/120 volts, single-phase, three-wire) _____

7. Transfer Switch (describe) _____

8. Asymmetrical Fault Current at Main Panelboard or Switchboards _____ amperes
9. Panelboards and Switchboards (describe) _____

10. Outdoor Lighting:
    a. Objective (describe) _____

    b. Luminaires (describe) _____

    c. Switching method (describe) _____

15.2   DC SYSTEM

1. DC System Loads (list) _____

2. Nominal Voltage _____ volts
3. Battery:
   a. Cell type _____
   b. Ampere-hours _____
   c. Number of cells _____
4. Battery Charger (describe) _____

   a. DC amps _____

16   CONTROL HOUSE

16.1   INSIDE DIMENSIONS

1. Length _____ m (_____ ft)
2. Width _____ m (_____ ft)
3. Clear Height _____ m (_____ ft)

16.2   BASEMENT (yes or no) _____

16.3   FOUNDATION

1. Footings:
   a. Width _____ cm (_____ in.)
   b. Depth _____ m (_____ ft)
   c. Depth below grade _____ m (_____ ft)
2. Foundation Walls:
   a. Type (cast-in-place concrete or concrete block)
   b. Perimeter Insulation (yes or no) _____
      (1) Type _____
      (2) Thickness _____ cm (_____ in.)
      (3) Location (inside or outside of walls) _____
3. Floor:
   a. Thickness _____ cm (_____ in.)
   b. Reinforcing (describe) _____

   c. Cast-in-Concrete Cable Trench (yes or no) (describe) _____

16.4   SUPERSTRUCTURE

1. Type (pre-engineered metal or concrete block) _____
2. Roof Type (precast, prestressed concrete panels, or steel joists and steel decks) _____

3. Doors (itemize as listed below for each door size):
   a. Size _____ cm (_____ in.) x _____ cm (_____ in.)
   b. Quantity _____
4. Windows (itemize as listed below for each window size)
   a. Size _____ cm (_____ in.) x _____ cm (_____ in.)
   b. Quantity _____

16.5   CONTROL PANELS

1. Type (single, double, or duplex) _____
2. Function (list each panel) _____
3. Size _____ cm (_____ in.) x _____ cm (_____ in.)

16.6 CABLE TRAYS

1. Size _____ cm (_____ in.)
2. Method of Support (describe) _____

_____

16.7 LIGHTING

1. Average illumination _____ lumens/m^2 (lumens/ft^2)
2. Luminaires (describe) _____

_____

3. Emergency lighting (describe) _____

16.8 AIR CONDITIONING EQUIPMENT

1. Number of units _____.____
2. Type of units _____
3. Rating _____

16.9 HEATING EQUIPMENT

1. Number of units _____
2. Type of units _____
3. Rating _____

17 COMMUNICATIONS

17.1 COMMUNICATIONS CHANNEL PLAN

Completing the following information for each channel needed:

1. Application (relaying, SCADA, telemetering, voice, other)
2. Bandwidth or capacity (may be expressed in bits/second)
3. End-to-end channel delay constraints
4. Remote terminating point(s)
5. Reliability/redundancy requirements

17.2 TOTAL CHANNEL CAPACITY

Define total channel capacity.

17.3 EXPANSION REQUIREMENTS OR FUTURE CAPABILITIES

Define expansion requirements or future capabilities that need to be accommodated.

17.4 <u>COMMUNICATIONS TECHNOLOGY</u>

Select a communications technology based on the parameters defined above:

1. Power line carrier
2. Audio tone
3. Carrier or audio tone on shield wire
4. Microwave (analog, digital, or MAS)
5. Fiber optics
6. Wire lines
7. Satellite

CHAPTER 4
PHYSICAL LAYOUT

4.1   INTRODUCTION

This chapter presents general information concerning the design of the substation physical arrangement. It describes various types of substations, illustrates typical layouts, and presents guidelines to be used during detailed design. Information concerning insulation, electrical clearances, bare conductors, substation bus design, and the application of mobile transformers and mobile substations is included.

4.2   LAYOUT CONSIDERATIONS

4.2.1   Initial Design Parameters

A careful analysis of basic parameters establishing the purposes and design criteria for the substation has to precede the detailed design. Much of this information can be found on the Substation Design Summary form of Appendix B to Chapter 3. In addition, circuit quantities, configurations, and ratings; system and equipment protective relay schemes; the necessity for specialized equipment (such as capacitor banks, current-limiting reactors, and neutral grounding devices); details of surge protection equipment; and requirements for direct stroke protection should be considered.

4.2.2   Selection of Switching Scheme

The power system as a whole has to be considered when deciding the substation switching scheme. Future system growth based on long-range forecasts may indicate the necessity for an economical, basic arrangement initially with possible future conversion to a more sophisticated scheme as the number of circuits increases. Important circuits may require additional protection or redundant supply. Equipment maintenance requirements may necessitate bypassing facilities to enable circuit operation during maintenance periods. Since the equipment that can be out of service for maintenance or during faults without sacrificing system operation depends on alternative supplies and duplication of circuits, the flexibility of the switching scheme is often one of the most important selection criteria. Large substations with many circuits handling great amounts of power need to have high degrees of both flexibility and reliability to continue service without interruption during the most undesirable conditions. Since flexibility and reliability are directly proportional to cost, the ultimate configuration has to be the result of a compromise.

4.2.3   Substation Expansion

Frequently, after initial substation construction, requirements change, and plans for the ultimate capabilities of the substation are altered. As a result, expansion of the substation facilities may deviate from the anticipated initial plan. To accommodate unforeseen future system modifications, consider the flexibility of the arrangement. Since a typical substation can be expected to continue in service indefinitely, maintaining maximum flexibility throughout each stage of expansion will ensure the least costly and most efficient use of the facilities during the service period.

To facilitate future expansion, arrange the initial design to accommodate all requirements of a current long-range system forecast. The site should be as large as practical to allow for future development. Large areas readily allow for changes in the basic substation configuration and switching scheme should

future conditions so dictate. Leave at least one and preferably both ends of all major buses open for future expansion. When a basic initial arrangement is planned, placement of equipment should take into account future expansion of the substation into a more complex, reliable, and flexible configuration. Frequently, additional switches, switch stands, and bus supports are installed initially to facilitate future expansion.

4.2.4   Substation Profile

The profile of substation structures and equipment has become an increasingly important aspect to consider in substation layout. In the past, large lattice and box-type structures supporting overhead strain buses were commonly used. Most substations currently being designed and constructed use low-profile structures and rigid buswork, particularly for low-voltage distribution substations or in areas with natural environmental screening.

Low-profile construction generally uses lower structures with a minimum number of members for support. Larger pieces of equipment, such as power transformers and power circuit breakers, have become smaller over the years. Consequently, substations are considered less obtrusive overall. The height limitations causing the use of low-profile construction sometimes result in arrangements of increased area, particularly for the lower voltage levels. Generally, the advantages of easier equipment operation and maintenance as a result of reduced equipment sizes and effective locations make up for the expense of purchasing somewhat larger sites.

4.2.5   Underground Circuits

An effective method to improve substation appearance is to install circuits underground as they leave the substation. Low-profile construction using lower structures with fewer support members lends itself to the use of underground circuits. Installing underground circuits can similarly improve the appearance of substations with larger structures by reducing the size of some of the large supporting structures or eliminating them altogether.

4.2.6   Equipment Removal

Substation arrangements have to include adequate space for the installation and possible removal of large pieces of equipment such as power transformers and power circuit breakers. Buses, particularly in low-profile arrangements, even when at acceptable operating elevations, can block the removal of equipment. Consequently, it is important to consider equipment removal routes during the structure layout. Often the most desirable arrangement has the main buses at higher elevations than the buses and equipment in the substation bays. In this way, the main buses will not block the removal of equipment located in the substation interior.

Removable bus sections can also be provided to permit movement of large equipment. This, however, requires bus de-energization during the procedure.

Bay spacing has to be carefully evaluated during layout to allow for removal of equipment. In multi-bay configurations, it is common to limit the number of bays to two before increasing the bay center-to-center spacing. This allows equipment to be removed from a bay to the side and provides additional space for moving the equipment between a bay and an adjacent bay, as diagrammed in Figure 4-1.

BAY 1   BAY 2   BAY 3   BAY 4   BAY 5   BAY 6

ARROWS INDICATE
EQUIPMENT REMOVAL
ROUTES

ADDITIONAL SPACE FOR
EQUIPMENT REMOVAL
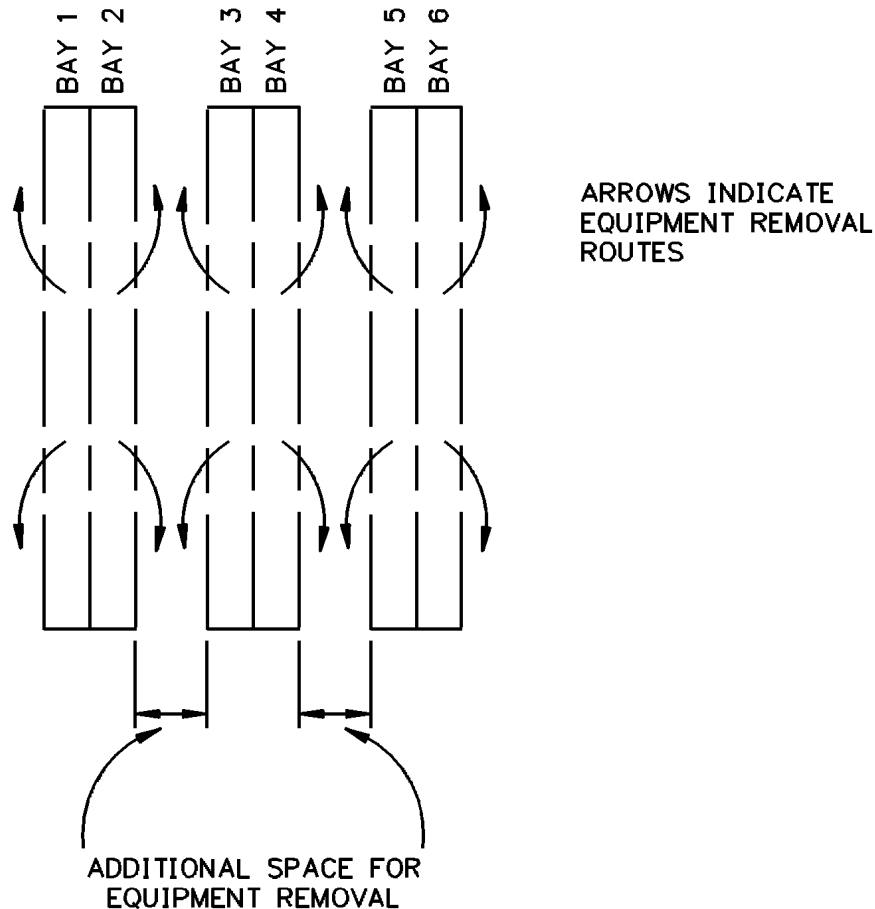
Figure 4-1: Substation Plan View Showing Space for Equipment Removal

4.3 DISTRIBUTION SUBSTATIONS

Distribution substations are usually characterized by voltages up to 230 kV on the primary side and 12.5Y/7.2 kV, 13.2Y/7.6 kV, 13.8Y/8.0 kV, 24.9Y/14.4 kV, or 34.5Y/19.9 kV on the secondary side.

In recent years, the trend has been toward increasing system voltages. It is becoming more common to eliminate the intermediate transmission substations and directly reduce the transmission voltages to primary distribution levels. The distribution substations discussed are generally limited to the traditional type characterized by simple bus arrangements and minimal equipment. However, the arrangements can be expanded for use in larger distribution substations with higher voltages.

4.3.1 Basic Distribution Substation

Figure 4-2 is a one-line diagram for a basic distribution substation. Depending on the load being served, it is possible that initial construction may be limited to one distribution circuit.

The subtransmission circuit enters the substation through a primary disconnect switch used principally to isolate the substation from the subtransmission system for maintenance or when replacement of substation equipment is required. It is usually of the three-pole, single-throw, group-operated type.
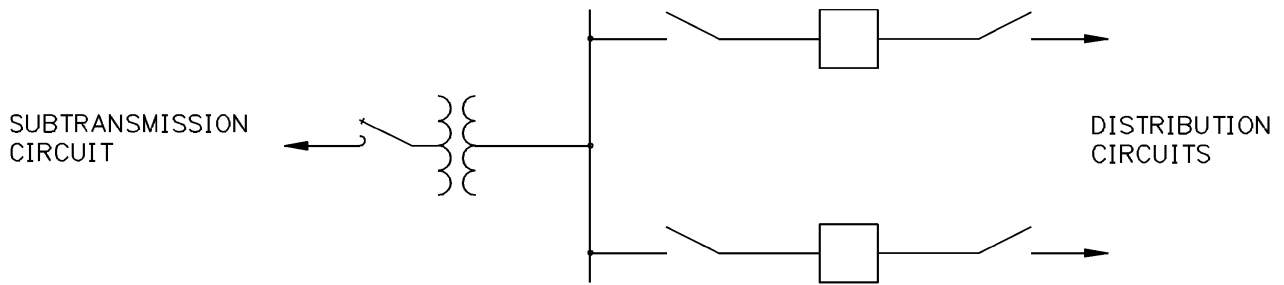
Figure 4-2: Basic Distribution Substation

The power transformers commonly used in this application are two-winding type and may be single- or three-phase units. In new substations and when replacing transformers or increasing transformer capacity, the trend has been toward using three-phase transformers. In configurations using single-phase transformers, a fourth transformer may be added as a spare. Use of three-phase transformers results in a neater and less cluttered arrangement. However, since failure of a three-phase transformer means loss of the substation, the overall design layout should provide facilities for the rapid installation of a mobile transformer or a mobile substation.

The two primary distribution feeders of the substation illustrated in Figure 4-2 are protected by either power circuit breakers or automatic circuit reclosers. Disconnect switches on both the source and load sides permit isolation during maintenance or other periods when complete de-energization is required. The switches can be either single-pole, single-throw, hook stick-operated or three-pole, single-throw, group-operated, depending on the arrangement.

4.3.2   Transformer Primary Protective Devices

To prevent equipment damage from transformer or low-voltage bus faults, protective devices are generally provided on the primary side of the transformer. These devices may also serve as primary disconnects to enable isolation from the transmission system.

Several types of devices are available, including power fuses, circuit breakers, circuit switchers, and vacuum interrupters. Selection of the type of device is based on the voltage, short-circuit conditions, and transformer capacity.

4.3.3   Voltage Regulation

To maintain voltage at a uniform level, voltage regulation equipment is usually required in rural distribution substations. The voltage can be regulated by using either feeder or bus regulation. Feeder regulation may be used in multi-circuit distribution substations, where the circuits are very diverse in load characteristics. With feeder regulation, the voltage of each distribution circuit can be individually maintained to conform to the load characteristics. Bus regulation may be used in rural distribution substations where the distribution feeders have similar load characteristics. Bus voltage may be controlled by using power transformers with load tap changing mechanisms, single- or three-phase voltage regulators, or switched capacitor banks.

To permit voltage regulator maintenance without feeder or bus de-energization, bypass facilities are provided as illustrated in Figure 4-3.

BUS REGULATION   FEEDER REGULATION
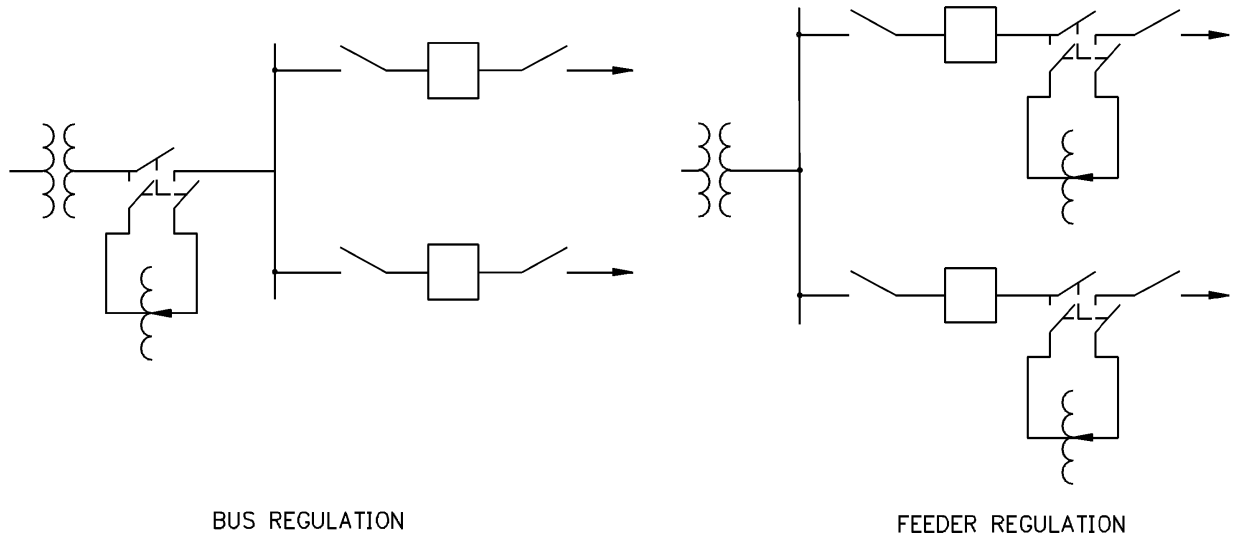
Figure 4-3: Voltage Regulator Bypass Arrangements

The switches normally used for regulator bypassing automatically combine all switching operations and perform them in the correct operating sequence. Each combined switch can usually be installed in the same space as one single-pole disconnect switch.

For a detailed discussion concerning the application of voltage regulators, see RUS Bulletin 1724D-114, "Voltage Regulator Application on Rural Distribution Systems."

4.3.4   Circuit Breaker/Recloser Bypass Facilities

Bypass facilities permit circuit breaker or recloser maintenance or repair without circuit de-energization. Figure 4-4 illustrates a typical bypass arrangement.

The bypass switches usually consist of three independently operated hook stick switches, but a three-pole group-operated switch can also be used. In some applications, it may be desirable to combine some of the switches to facilitate installation. Figure 4-5 illustrates one possible configuration.

In this configuration, a tandem switch is used to combine the bypass switch and the load side disconnect switch onto a single switch base. The combined switch can be installed in nearly the same space as one single-pole disconnect switch.

To provide circuit protection during bypassing, the bypass switch can be replaced by a fuse.
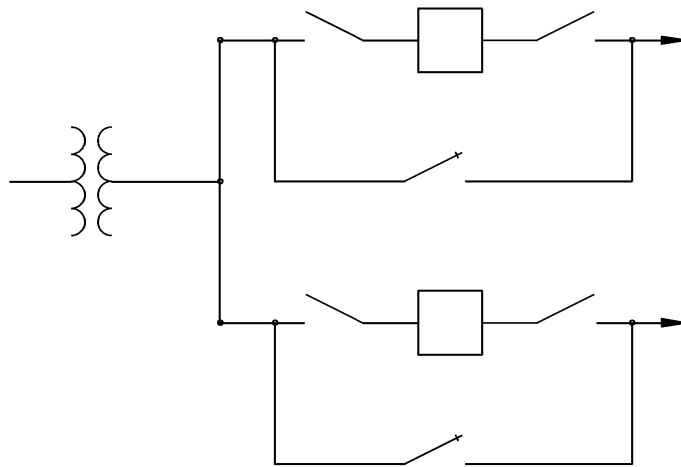
Figure 4-4: Typical Circuit Breaker/Recloser Bypass Arrangement
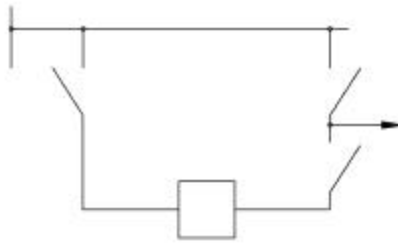
Figure 4-5: Use of Tandem Switches for Circuit Breaker/Recloser Bypassing

4.3.5 Surge Arresters

Transformers, regulators, and other substation equipment are particularly sensitive to transient overvoltages. For the highest degree of equipment protection, surge arresters should be installed as close as practical to the equipment being protected. In most instances, power transformers can be furnished with surge arrester mounting brackets to facilitate installation. Separate arrester stands can also be used, or the arresters can be installed on adjacent switching structures. For voltage regulator applications, the surge arresters are normally installed directly on the regulator tanks.

When power transformers are protected by fuses, it is recommended that transformer surge arresters be connected on the line side of the fuses, as close as practical to the power transformers. This will minimize the stress on the fuse and help avoid partial melting of the fuse link when the surge arrester responds to a transient overvoltage.

4.3.6 Enclosed Equipment

In certain applications, particularly when space is at a premium, consider use of switchgear, unit substations, or partially enclosed equipment. Switchgear is a name commonly used in referring to groupings of switching equipment contained in metal enclosures. All circuit breakers, metering and control equipment, and interconnecting buswork are contained inside the enclosures.

A unit substation consists of switchgear electrically and mechanically connected to at least one power transformer. Various arrangements of power transformers and switchgear equipment are available to suit individual requirements.

Use of switchgear, unit substations, and other types of enclosed equipment eliminates the need for extensive field construction since most of the equipment is preassembled by the manufacturer or supplier. Depending on the configuration, the equipment may be shipped completely assembled or in sections to be connected together at the job site. Feeders are normally installed underground from the switchgear compartments.

Partial enclosure of some of the low-voltage distribution equipment can be implemented to improve the appearance of the substation. The equipment can be furnished in modular form to facilitate installation. Interconnections between modules are usually underground, although overhead bus duct is occasionally used.

4.4 TRANSMISSION SUBSTATIONS

Transmission substations are usually characterized by primary and secondary voltages of 69 kV or higher. Since one transmission substation may supply several distribution substations and large loads, reliability of service and flexibility of operation are extremely important. Facilities normally allow equipment maintenance without circuit interruption. Multiple bus arrangements and extensive use of circuit breakers for switching provide added system flexibility.

4.4.1 Basic Transmission Substation

Figure 4-6 is a one-line diagram for a basic transmission substation. Depending on system requirements, initial substation construction may be limited to one power transformer and one subtransmission circuit.
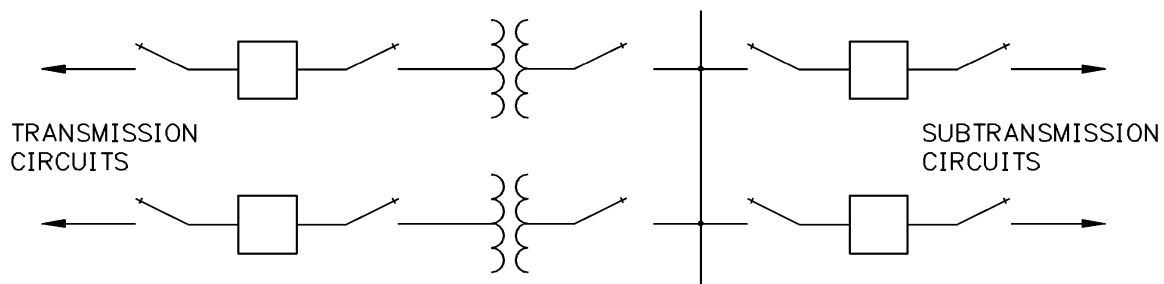
Figure 4-6: Basic Transmission Substation

Power circuit breakers are included in the two transmission circuits to help prevent complete substation shutdown for line faults. The circuit breakers have disconnect switches on both source and load sides to permit isolation during maintenance or other periods requiring complete de-energization. These switches are normally of the three-pole, single-throw, group-operated type, mounted on separate stands.

The power transformers commonly used are three-phase autotransformers, usually with tertiary windings. Three-phase two-winding transformers are used when phase relationships have to be sustained between the primary and the secondary systems. The disconnect switches on the low-voltage sides of the power

transformers allow de-energization of one transformer while maintaining service to both low-voltage circuits from the other transformer.

The low-voltage or secondary section of the substation illustrated in Figure 4-6 consists of two subtransmission feeders protected by power circuit breakers. Disconnect switches on both the source and load sides permit isolation during maintenance or other periods when complete de-energization is required. The switches are normally of the three-pole, single-throw, group-operated type, but can be of the single-pole, single-throw, and hook stick-operated type, depending on the voltage and arrangement. Hook stick-operated switches usually are not considered above 69 kV.

4.4.2   Circuit Breaker Bypass Facilities

Bypass facilities can be provided for the power circuit breakers to permit maintenance without circuit de-energization. Figure 4-7 illustrates a typical arrangement.
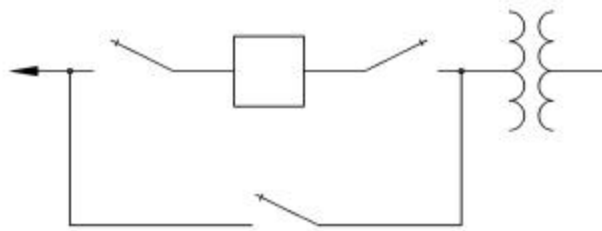
Figure 4-7: Typical Circuit Breaker Bypass Arrangement

The bypass facilities normally consist of three independent three-pole, single-throw, group-operated switches. The circuit breaker disconnect switches may be of the single-pole, single-throw, hook stick-operated type, depending on system voltage and bus configuration.

In most cases bypassing circuit breakers removes normal relay protection since the circuit breaker current transformers are also removed from service. The overall protection scheme, have to be designed to provide for this situation. Fused bypass switches may be used for temporary feeder protection.

4.4.3   Surge Arresters

Because of the desire for high reliability and the high cost of equipment replacement, surge arresters are installed in various positions in transmission substations. Since power transformers are particularly sensitive to overvoltages, they normally have arresters on each phase of both the primary and secondary. Also install arresters on each ungrounded phase of the tertiary winding when it is brought out to provide service.

The highest degree of equipment protection occurs with the surge arresters located as close as possible to the equipment to be protected. Power transformers can usually be furnished with arrester mounting brackets adjacent to the transformer bushings.

Occasionally, surge arresters or other surge protective equipment are located at the line entrances and exits. In these instances, it is best to locate the arresters or other protective equipment on the line side of the substation equipment to be protected to limit the lightning and switching surges to acceptable levels as they enter the substation. Locating the arresters on the line side of the circuit breakers will also protect the gap in the breakers when in the open position.

4.4.4   Carrier Equipment

Line traps, coupling capacitor voltage transformers, and associated accessories are used when relaying or communications systems dictate use of carrier equipment for signal transmission to remote terminals. Normally, the line traps and coupling capacitor voltage transformers are installed on separate stands located near the circuit entrance positions in the substations. In some instances, the two pieces of equipment may be mounted on a common structure or stand, depending on the arrangement. The particular relaying and communications schemes being used on the circuit will dictate the number of phases containing line traps and coupling capacitor voltage transformers.

4.4.5   Voltage Transformers

Voltage transformers are used in conjunction with the circuit and equipment protection, synchronization, and metering schemes. They are normally mounted on individual or three-position stands. Depending on the bus configuration and the relaying schemes, the voltage transformers may be positioned near the circuit entrance positions or adjacent to the buses.

It is usually desirable to provide a method for disconnecting the voltage transformers. One possible method is to install the primary connections to the appropriate buses by using disconnectable clamps. In arrangements using voltage transformers at the circuit positions, they can be positioned to allow de-energization by opening the power circuit breaker and the line disconnect switches.

4.4.6   Current Transformers

Current transformers used in both relaying and metering schemes can usually be located inside major equipment such as power circuit breakers and power transformers. These current transformers are normally multi-ratio bushing type and therefore do not require special mounting provisions. In some cases, separately mounted current transformers may be required, such as for revenue metering purposes. They are usually installed on individual stands and located as required.

4.4.7   Grounding Switches

Manually operated grounding switches are frequently used to ground incoming circuits during maintenance or other out-of-service periods. These switches can be separately mounted or, as is usually the case, can be furnished as part of the circuit disconnect switches. The switches can then be interlocked in such a way as to prevent both from being closed simultaneously.

High-speed grounding switches are sometimes used in power transformer protection schemes to initiate tripping of remote circuit breakers during transformer faults. As with manually operated grounding switches, high-speed grounding switches can be separately mounted or can be furnished as part of group-operated disconnect switches. High-speed grounding switches are normally installed on one phase only. The use of high-speed grounding switches, while still in practice, is generally not preferred since its use subjects the system to more of a shock and potentially affects more customers on the system.

4.5   SWITCHING STATIONS

Switching stations do not change system voltage from one level to another and therefore do not contain power transformers. Switching stations usually operate at subtransmission or transmission voltage levels.

Depending on system voltage, the equipment types and characteristics used in switching stations are identical to those used in transmission stations.

4.5.1   Basic Switching Substation

Figure 4-8 is a one-line diagram for a basic switching substation with three terminals.
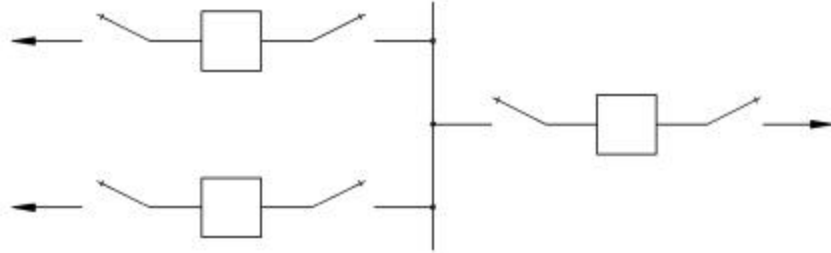
Figure 4-8: Basic Switching Substation

Power circuit breakers in the three circuits help prevent complete substation shutdown for line faults. The circuit breakers have disconnect switches on both source and load sides to permit isolation during maintenance or other periods requiring complete de-energization. Depending on station voltage and bus configuration, the switches may be of the three-pole, single-throw, group-operated type or of the single-pole, single-throw, hook stick-operated type. Hook stick-operated switches usually are not considered above 69 kV.

Bypass facilities can be provided to allow circuit breaker maintenance without de-energizing the circuit. See Section 4.4.2 of this chapter for more information concerning circuit breaker bypass facilities.

4.5.2   Surge Arresters

Surge arresters or other surge protection equipment may be installed either on the line positions or on the substation buses to protect against excessive lightning or switching surges.

A comparison of the costs of the surge protection equipment to the frequency and extent of possible equipment damage can be evaluated to determine the desirability of the protective equipment. Possible circuit or substation outages and equipment damage as a result of the unprotected surges should be considered. In general, if there is any question, surge arresters should be installed for equipment and circuit protection.

4.6   TYPICAL BUS CONFIGURATIONS

The typical bus configurations may be used for distribution, transmission, or switching substations at voltages up to 345 kV. Details will vary depending on the type and voltage(s) of the substations. The physical size, type, and arrangement of major equipment, such as power transformers, power circuit breakers, and switches, may cause variance in the layouts to suit individual requirements. Portions of different layouts may be combined, as required, to achieve desired configurations.

It is important that the engineer's plans remain as flexible as possible during substation layout to allow for unforeseen difficulties as designs progress. Coordinate activities with the equipment manufacturers to ensure that each design detail reflects the actual equipment to be used.

4.6.1 <u>Single Bus</u>

A single bus configuration consists of one main bus that is energized at all times and to which all circuits are connected. This arrangement is the simplest, but provides the least amount of system reliability. Bus faults or failure of circuit breakers to operate under fault conditions results in complete loss of the substation. The single bus configuration can be constructed by using either low- or high-profile structures. Figure 4-9 illustrates the single bus arrangement with low-profile structures and presents a neat, orderly plan. The high-profile design, shown in Figure 4-10, accomplishes the same purpose and may not require as large a site for a given system voltage.

The single bus arrangement is not recommended without circuit breaker bypass facilities that permit circuit breaker maintenance while maintaining circuit operation. The high-profile configuration can easily be modified to provide this feature by installing group-operated switches and the associated buswork and connections in the positions shown in Figure 4-10. This arrangement, however, results in loss of overcurrent protection for the circuit except by remote circuit breakers during the bypassing operations. A fault occurring on the line with the breaker bypassed would result in complete substation shutdown. The low-profile arrangement does not allow for future addition of this type of bypassing equipment. Consequently, in both low-profile and some high-profile substations, the bypass facilities can be installed outside the substation. Switches can be provided that, when closed, parallel two lines to enable one circuit breaker to be removed from service. The other breaker then protects both circuits. If this bypassing method is used, the equipment associated with both circuits, have to be capable of carrying the total load of both circuits. If the load is greater than the equipment capability, the load should be reduced. This method of circuit breaker bypassing may be more desirable in high-profile arrangements than that shown in Figure 4-10 for lines where frequent or lengthy equipment maintenance is expected.

The high-profile configuration shown in Figure 4-10 is generally limited to distribution and subtransmission voltage levels. At transmission voltage levels, independent structures and strain bus interconnections are usually used.

4.6.1.1 **Advantages:**

1. Lowest cost
2. Small land area required
3. Easily expandable
4. Simple in concept and operation
5. Relatively simple for the application of protective relaying

4.6.1.2 **Disadvantages:**

1. High-profile arrangement equipped with circuit breaker bypass facilities does not provide for circuit protection when bypass facilities are being used inside the substation.
2. A single bus arrangement has the lowest reliability.
3. Failure of a circuit breaker or a bus fault causes loss of the entire substation.
4. Maintenance switching can complicate and disable some of the protective relay scheme and overall relay coordination.
5. Maintenance at the upper elevations of high-profile arrangements necessitates de-energization or protection of the lower equipment.
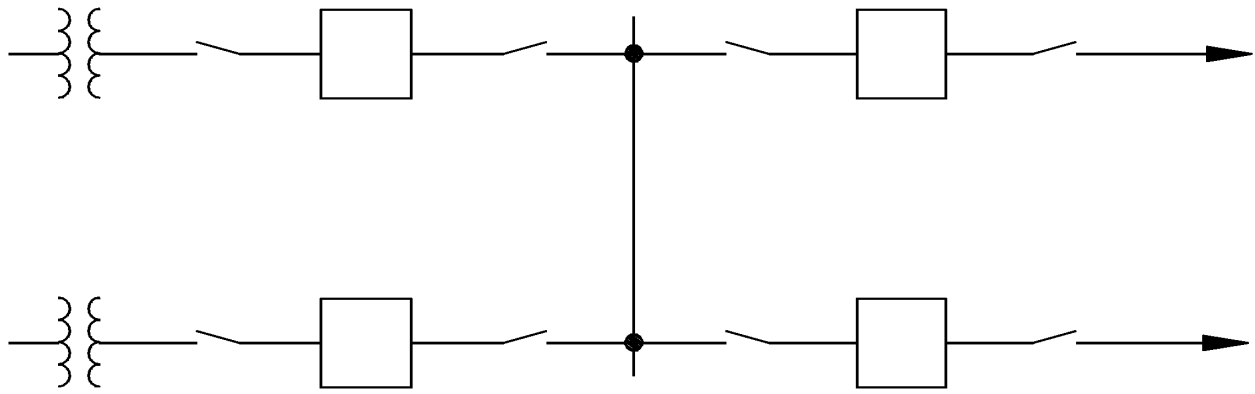
TYPICAL ONE-LINE DIAGRAM
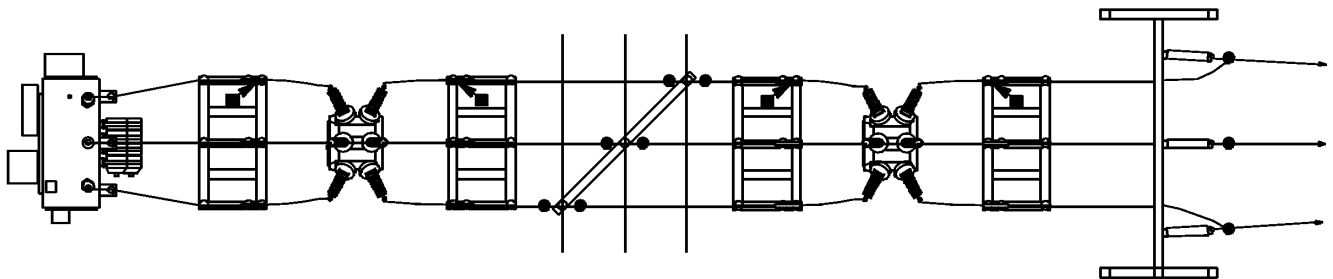
PLAN VIEW—TYPICAL BAY
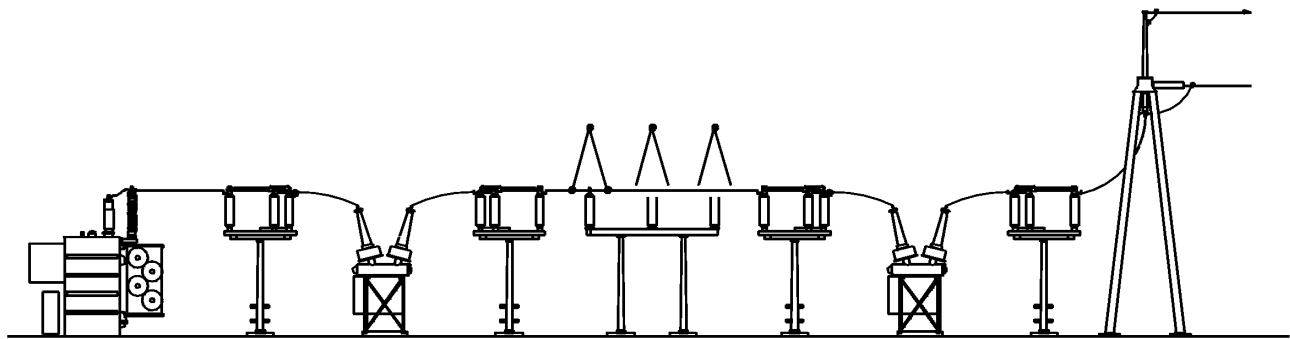
ELEVATION—TYPICAL BAY

Figure 4-9: Single Bus—Low Profile

FUTURE CIRCUIT BREAKER BYPASS SWITCHES

TYPICAL ONE-LINE DIAGRAM

PLAN VIEW-TYPICAL BAY

FUTURE CIRCUIT
BREAKER BYPASS
SWITCHES
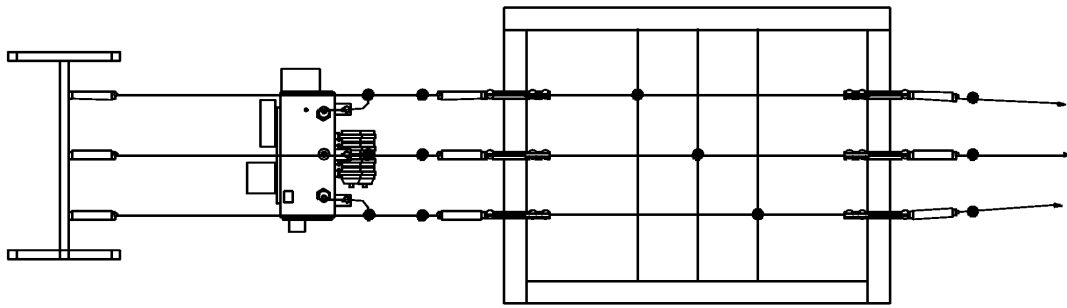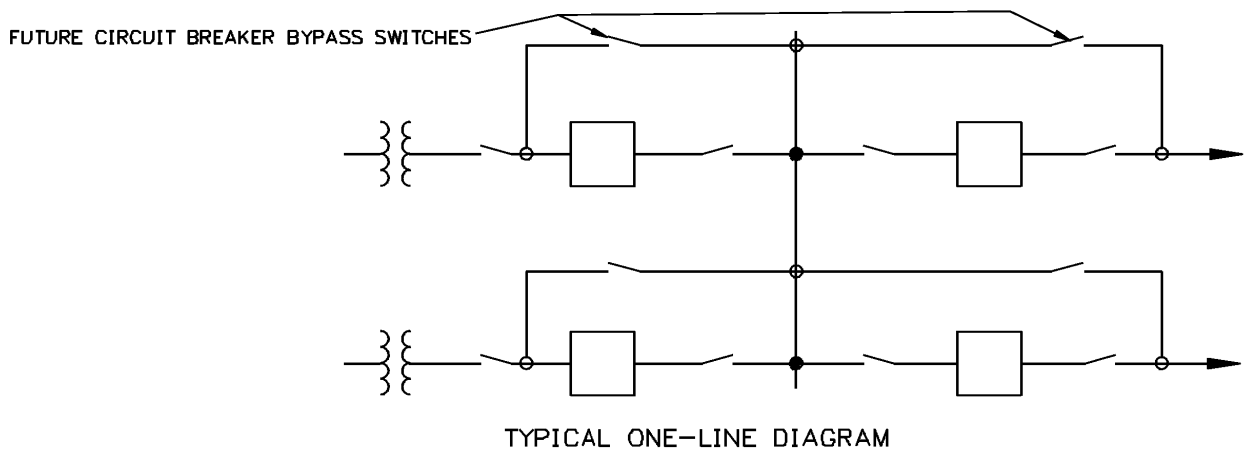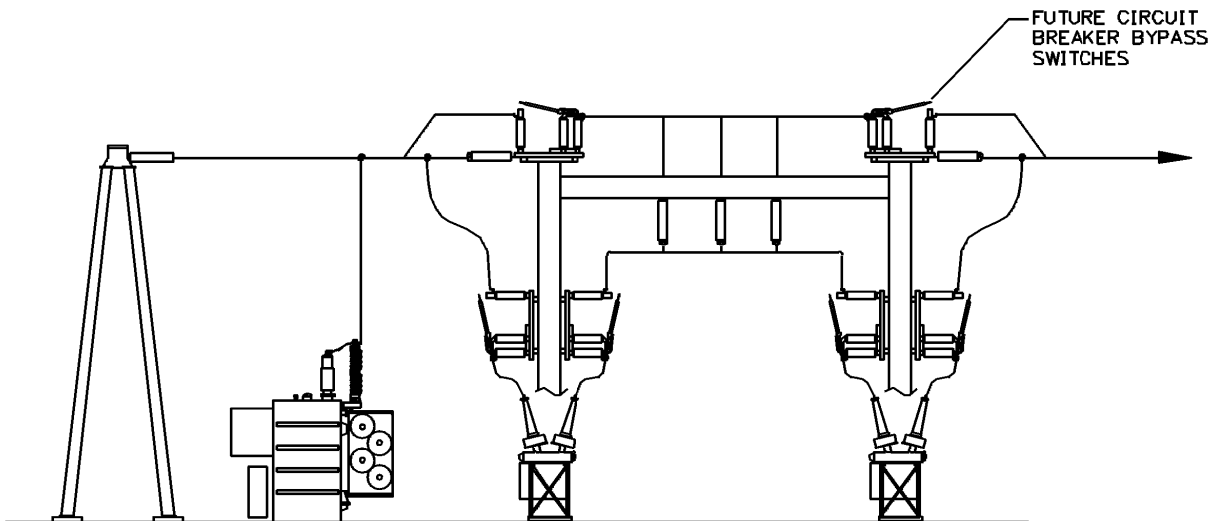
ELEVATON-TYPICAL BAY

Figure 4-10: Single Bus—High Profile

4.6.2 Sectionalized Bus

An extension of the single bus configuration is the sectionalized bus arrangement shown in Figure 4-11. This arrangement is basically two or more single bus schemes, each tied together with bus sectionalizing breakers. The sectionalizing breakers may be operated normally open or closed, depending on system requirements. In this arrangement, a bus fault or breaker failure causes only the affected bus section to be removed from service and thus eliminates total substation shutdown. Usually, the fault can be isolated and nonfaulted portions of the system restored to service easier and faster because of the increased flexibility of this arrangement.
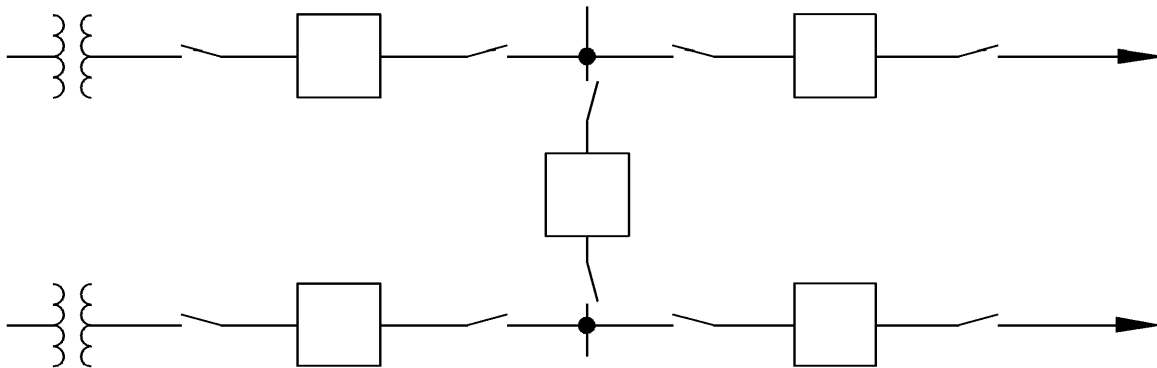
TYPICAL ONE-LINE DIAGRAM

(SEE FIGURES 4-9 & 4-10
FOR TYPICAL ARRANGEMENTS)

Figure 4-11: Sectionalized Bus

Physically, the equipment can be organized similar to that shown in Figures 4-9 and 4-10 for the single bus arrangement. The sectionalizing breakers and their associated isolation switches are located in line with the main bus. In the high-profile configuration, it is usually desirable to provide a separate bay for the sectionalizing breakers and switches to facilitate maintenance and removal.

The arrangement of lines and transformers in a sectionalized bus arrangement depends on system operating criteria. They should be arranged so as to prevent outage of lines or other circuits dependent on each other. This can be accomplished by positioning the interrelated circuits on different bus sections to eliminate concurrent shutdown. Perform a thorough analysis of all possible operational contingencies identifying any undesirable conditions preceding the final determination of circuit grouping.

Bypassing arrangements for the sectionalized bus configuration can be provided as explained for the single bus scheme.

4.6.2.1 Advantages:

1. Flexible operation
2. Higher reliability than single bus scheme
3. Isolation of bus sections for maintenance
4. Loss of only part of the substation for a breaker failure or a bus fault

4.6.2.2 Disadvantages:

1. A sectionalized bus arrangement has a higher cost than a single bus scheme.
2. Additional circuit breakers are required for sectionalizing.
3. Sectionalizing may cause interruption of nonfaulted circuits.

4.6.3   Main and Transfer Bus

A main and transfer bus configuration consists of two independent buses, one of which, the main bus, is normally energized. Under normal operating conditions, all incoming and outgoing circuits are fed from the main bus through their associated circuit breakers and switches. If it becomes necessary to remove a circuit breaker from service for maintenance or repairs, the integrity of circuit operation can be maintained through use of the bypass and bus tie equipment. The bypass switch for the circuit breaker to be isolated is closed, the bus tie breaker and its isolation switches are closed, and the bypassed breaker and its isolation switches are opened to remove the breaker from service. The circuit is then protected by the bus tie breaker.

Figure 4-12 illustrates a main and transfer bus configuration in a low-profile arrangement. For comparison, Figure 4-13 shows the same switching scheme with high-profile box-type structures. With the box-type structure arrangement, two circuit positions can be accommodated per equipment bay. However, with the low-profile arrangement, each circuit requires its own bay and, as a result, somewhat more land area may be required. When the low-profile configuration is used, equipment bays should be limited in width to a maximum of two bays before the bay-to-bay centerline spacing is increased to accommodate circuit breaker maintenance and removal. Without the additional space, these tasks can become very difficult.

The high-profile, box-type structure arrangement shown in Figure 4-13 can accommodate multiple circuits in a relatively small area. The configuration is particularly suitable in environmentally shielded or otherwise isolated locations, where only a limited substation site is available. This arrangement is generally limited to distribution and subtransmission voltage levels. At transmission voltage levels, independent structures and strain bus interconnections can be used.

4.6.3.1 Advantages:

1. Accommodation of circuit breaker maintenance while maintaining service and line protection
2. Reasonable in cost
3. Fairly small land area
4. Easily expandable

4.6.3.2 Disadvantages:

1. An additional circuit breaker is required for bus tie.
2. Since the bus tie breaker, have to be able to be substituted for any line breaker, its associated relaying may be somewhat complicated.
3. Failure of a circuit breaker or a bus fault causes loss of the entire substation.
4. Somewhat complicated switching is required to remove a circuit breaker from service for maintenance.

TRANSFER
BUS
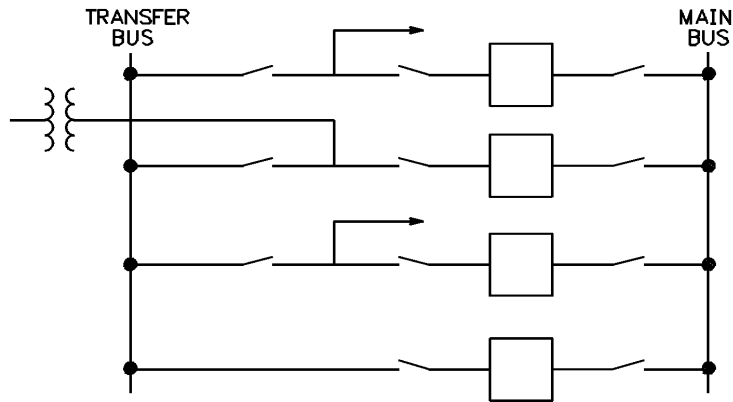
MAIN
BUS

TYPICAL ONE—LINE DIAGRAM
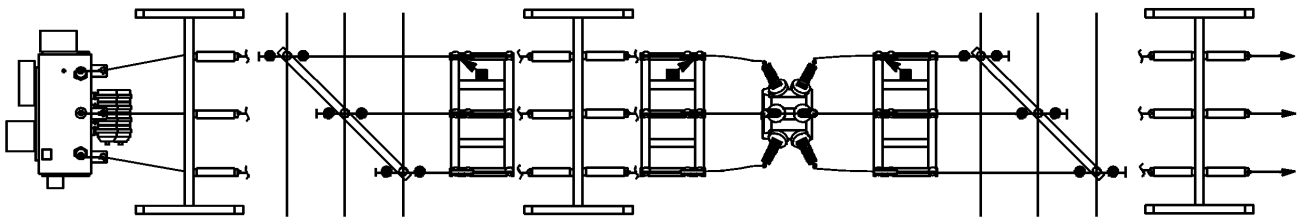
PLAN VIEW—TYPICAL BAY
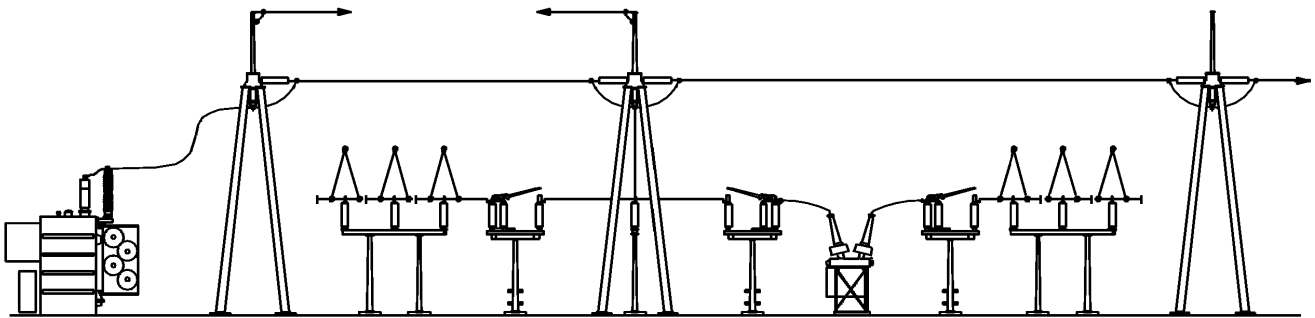
ELEVATION TYPICAL BAY

Figure 4-12: Main and Transfer Bus—Low Profile

TRANSFER   MAIN
BUS   BUS
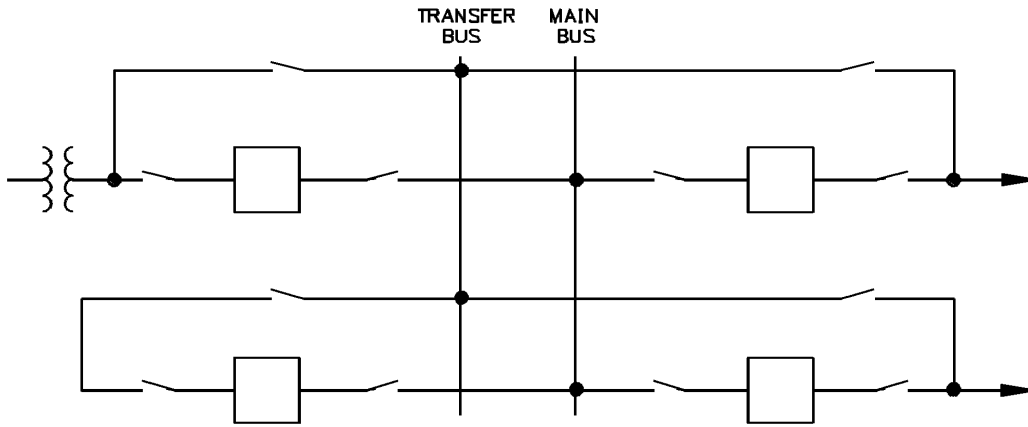
TYPICAL ONE—LINE DIAGRAM
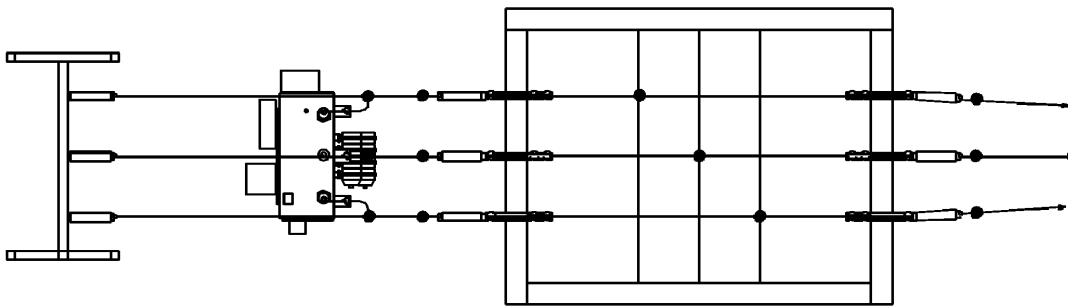
PLAN VIEW—TYPICAL BAY
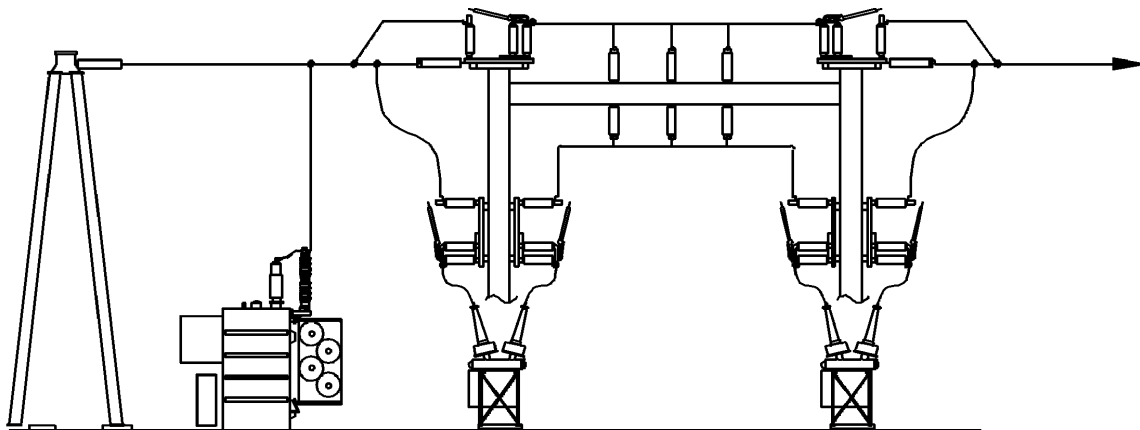
ELEVATON—TYPICAL BAY

Figure 4-13: Main and Transfer Bus—High Profile

4.6.4   Ring Bus

A ring bus configuration is an extension of the sectionalized bus arrangement and is accomplished by interconnecting the two open ends of the buses through another sectionalizing breaker. This results in a closed loop or ring with each bus section separated by a circuit breaker. For maximum reliability and operational flexibility, each section should supply only one circuit.

In this arrangement, as with the sectionalized bus configuration, only limited bus sections and circuits are removed from service because of line or bus faults or circuit breaker failure. For a line or bus fault, the two circuit breakers on the sides of the affected bus section open to isolate the fault. The remaining circuits operate without interruption. For a breaker failure, the two breakers on the sides of the affected breaker open, along with a transfer trip to a remote breaker, to isolate the failed breaker and remove two bus sections from service.

The ring bus arrangement provides for circuit breaker maintenance since any breaker can normally be removed from service without interruption of service to any circuits. As a result, separate circuit breaker bypass facilities are not required.

A number of equipment arrangements may be used to provide a ring bus configuration, depending on anticipated substation expansion and possible system modifications. Figure 4-14 illustrates a typical ring bus configuration. The arrangement shows four circuit positions, which is a practical maximum for a ring bus configuration. Rather than expanding the ring bus to accommodate additional circuits, other more flexible and reliable configurations, such as the breaker-and-a-half scheme, can be adopted. The ring bus arrangement shown in Figure 4-14 is readily adaptable in the future to a breaker-and-a-half configuration as shown in Figure 4-15. However, the relay and control panels have to be carefully planned to be modified later for breaker-and-a-half operation.

Bay centerline spacing should be carefully planned to permit equipment maintenance and removal.

4.6.4.1   Advantages:

1. Flexible operation
2. High reliability
3. Isolation of bus sections and circuit breakers for maintenance without disrupting circuit operation
4. Double feed to each circuit
5. No main buses
6. Expandable to breaker-and-a-half configuration
7. Economic design

4.6.4.2   Disadvantages:

1. Ring may be split by faults on two circuits or a fault during breaker maintenance to leave possibly undesirable circuit combinations (supply/load) on the remaining bus sections. Some consider this, however, to be a second contingency factor.
2. Each circuit has to have its own potential source for relaying.
3. This configuration is usually limited to four circuit positions, although larger rings are in service, including 10-position ring buses. A 6-position ring bus is usually considered as a maximum limit for the number of terminals in a ring bus.
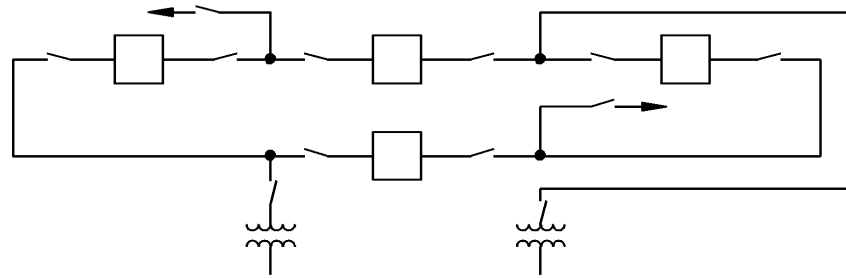
TYPICAL ONE−LINE DIAGRAM
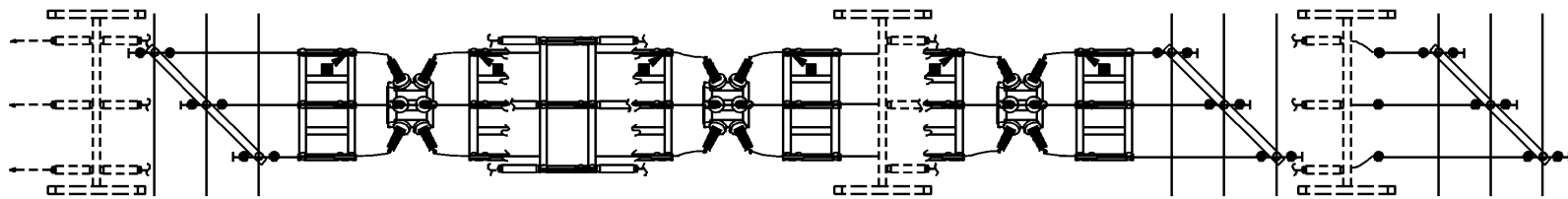
PLAN VIEW — TYPICAL BAY
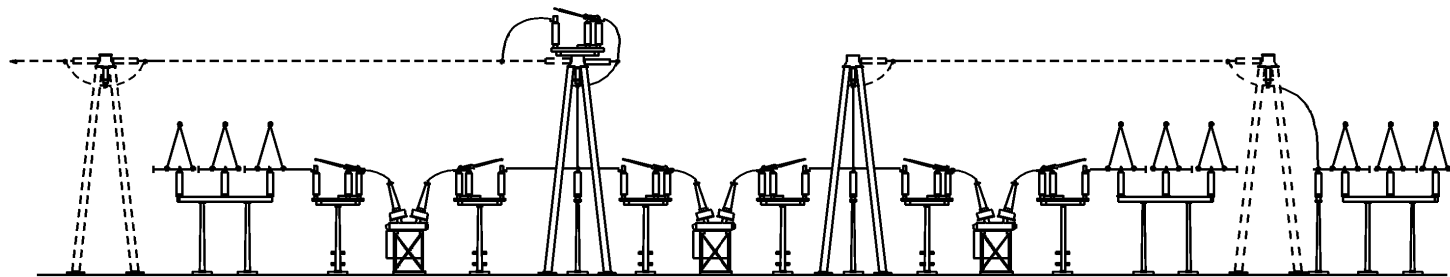
ELEVATION — TYPICAL BAY

Figure 4-14: Ring Bus

TYPICAL ONE-LINE DIAGRAM

PLAN VIEW—TYPICAL BAY

ELEVATION—TYPICAL BAY
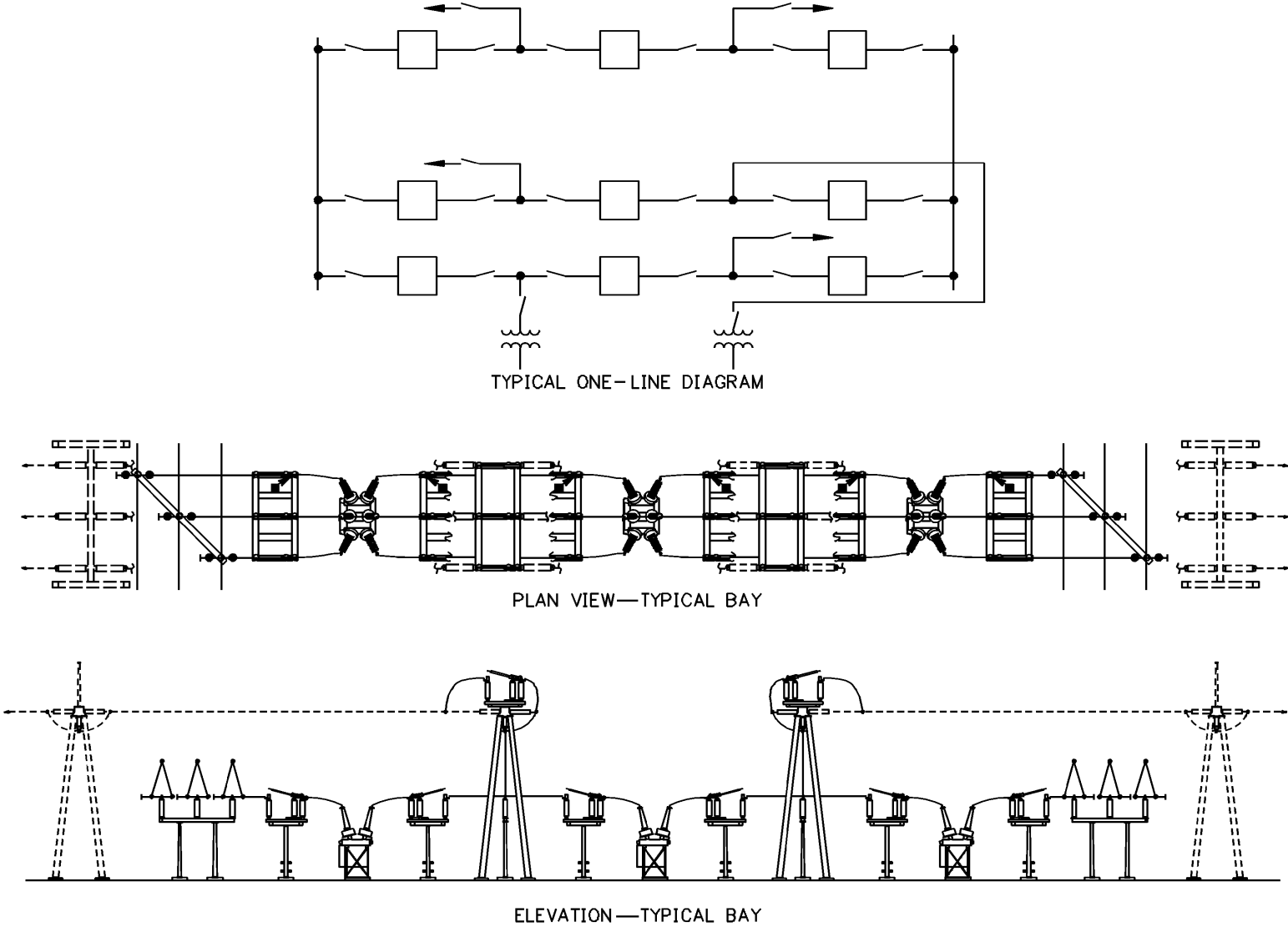
Figure 4-15: Breaker-and-a-Half

4. This is a more involved relay scheme since each breaker has to respond to faults on two circuits.
5. Automatic reclose schemes may be complex.

4.6.5   Breaker-and-a-Half

The breaker-and-a-half configuration consists of two main buses, each normally energized. Electrically connected between the buses are three circuit breakers and, between each two breakers, a circuit as diagrammed in Figure 4-15. In this arrangement, three circuit breakers are used for two independent circuits; hence, each circuit shares the common center circuit breaker, so there are one-and-a-half circuit breakers per circuit.

The breaker-and-a-half configuration provides for circuit breaker maintenance, since any breaker can be removed from service without interrupting any circuits. Additionally, faults on either of the main buses cause no circuit interruptions. Failure of a circuit breaker results in the loss of two circuits if a common breaker fails and only one circuit if an outside breaker fails.

A typical bus configuration for a breaker-and-a-half arrangement is shown in Figure 4-15. This is the same basic equipment assemblage as described for the ring bus scheme.

Frequently, substations are initially constructed with a ring bus arrangement and ultimately expanded into a breaker-and-a-half configuration to obtain the additional flexibility and reliability required with the additional circuits.

Bay centerline spacing should be carefully planned to permit equipment maintenance and removal.

4.6.5.1   Advantages:

1. Flexible operation
2. High reliability
3. Can isolate either main bus for maintenance without disrupting service
4. Can isolate any circuit breaker for maintenance without disrupting service
5. Double feed to each circuit
6. Bus fault does not interrupt service to any circuits
7. All switching done with circuit breakers

4.6.5.2   Disadvantages:

1. One-and-a-half breakers are required per circuit.
2. Relaying is involved, since the center breaker has to respond to faults of either of its associated circuits.
3. Each circuit should have its own potential source for relaying.

4.6.6   Double Breaker–Double Bus

The double breaker–double bus configuration consists of two main buses, each normally energized. Electrically connected between the buses are two circuit breakers and, between the breakers, one circuit, as diagrammed in Figure 4-16. Two circuit breakers are required for each circuit.
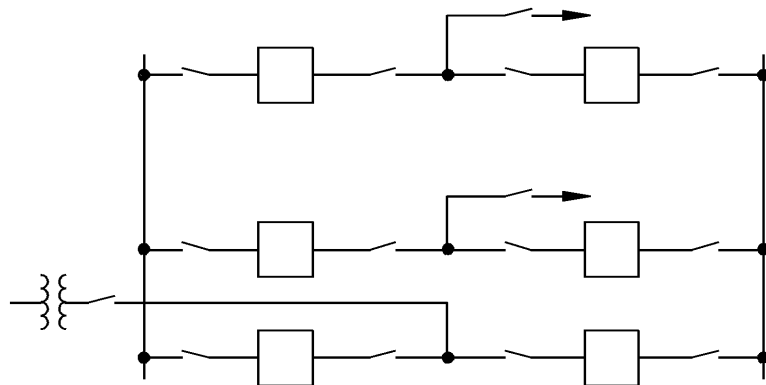
TYPICAL ONE-LINE DIAGRAM
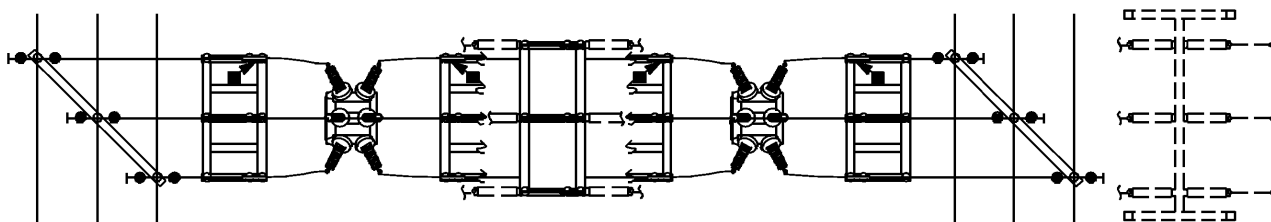
PLAN VIEW—TYPICAL BAY
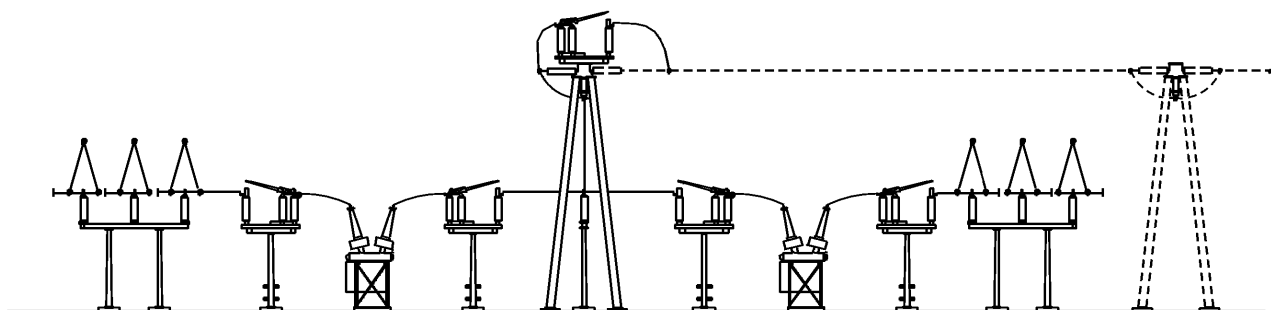
ELEVATION—TYPICAL BAY

Figure 4-16: Double Breaker-Double Bus

In the double breaker–double bus configuration, any circuit breaker can be removed from service without interruption of any circuits. Faults on either of the main buses cause no circuit interruptions. Circuit breaker failure results in the loss of only one circuit.

A typical bus configuration for a double breaker–double bus arrangement is shown in Figure 4-16.

Use of the double breaker–double bus configuration is usually limited to large generating stations because of the high cost. The additional reliability afforded by this arrangement over the breaker-and-a-half scheme usually cannot be justified for conventional transmission or distribution substations. Occasionally, at a generating station, one bay of a breaker-and-a-half arrangement is used as a double breaker–double bus arrangement for a generator terminal to provide equal access to either main bus.

4.6.6.1   Advantages:

1. Flexible operation
2. Very high reliability
3. Isolation of either main bus for maintenance without disrupting service
4. Isolation of any circuit breaker for maintenance without disrupting service
5. Double feed to each circuit
6. No interruption of service to any circuits from bus fault
7. Loss of only one circuit for breaker failure
8. All switching with circuit breakers

4.6.6.2   Disadvantages:

1. This configuration carries a high cost.
2. Two circuit breakers are required for each circuit.

4.6.7   Relative Switching Scheme Costs

The selection of a station switching scheme is the result of the evaluation of many factors, including such intangibles as personal preference and judgment. Whatever arrangement is finally selected should meet all known or anticipated requirements, such as operating and maintenance criteria, future expansion, and reliability.

To assist in the evaluation, Table 4-1 provides a reasonable measure for the basis of economic comparison.

Table 4-1: Switching Scheme Cost Comparison

Switching Scheme	Approximate Relative Cost Comparison
Single Bus	100%
Sectionalized Bus	122%
Main and Transfer Bus	143%
Ring Bus	114%
Breaker-and-a-Half	158%
Double Breaker–Double Bus	214%

The comparison is based on four-circuit low-profile arrangements with power circuit breakers in all circuits. Power transformer costs are not included. In schemes utilizing other protective devices or

different circuit quantities, the relative costs may vary from those listed. Prepare detailed construction estimates for all schemes under consideration.

4.7 PROTECTION OF SUBSTATION INSULATION

4.7.1   General

Substation electrical equipment is subject to abnormal conditions as a result of direct lightning strokes, lightning surges, switching surges, and faults on the system. These abnormal conditions can cause overvoltages that may result in equipment flashover or insulation failure. To prevent equipment damage and/or system shutdown from overvoltages, protective devices are used to limit the overvoltages to reasonable levels. Application of these devices is usually a compromise between the costs of the devices and the degree of protection desired.

The protection provided for substations and substation equipment can be broken into two main parts:

1. Surge protection, employed to protect the equipment from damaging overvoltages caused by lightning surges, switching surges, and system faults
2. Direct stroke protection, employed to protect the equipment from direct lightning strokes

4.7.2   Surge Protection

Surge arresters are used to protect equipment against overvoltages caused by incoming surges. The arresters function by discharging surge current to the ground system and then interrupt the current to prevent flow of normal power frequency follow current to ground. A detailed discussion concerning the application and selection of surge arresters can be found in Section 5.8.

4.7.3   Direct Stroke Protection

4.7.3.1   Shielding: Since the effects of a direct lightning stroke to an unshielded substation can be devastating, it is recommended that some form of direct stroke protection be provided. Direct stroke protection normally consists of shielding the substation equipment by using lightning masts, overhead shield wires, or a combination of these devices. The types and arrangements of protective schemes used are based on the size and configuration of the substation equipment.

4.7.3.2   Overhead Shield Wires: Overhead shield wires are often used to provide direct stroke protection. The shield wires can be supported by the circuit pull-off structures, if conveniently located, to extend over the substation. Since these shield wires are located above substation buses and equipment, breakage could result in outage of and/or damage to equipment. To minimize possible breakage, the overhead shield wire systems are constructed from high-quality, high-strength materials such as have been accepted by RUS (see RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers"). Shield wires should be limited to a maximum design tension of 8900 newtons (2000 pounds) per conductor under the appropriate loading conditions as defined in the *National Electrical Safety Code*. This tension is based only on wire strength and has to be coordinated with support structure design. Lower tensions may be required for certain applications, depending on the capabilities of the support structures. Sag has to be considered to ensure adequate clearance from energized equipment.

A complete overhead shield wire system should include protection for overhead circuits entering or leaving the substation. In areas not employing transmission line shielding, substation shield wire systems should be extended at least 805 meters (one-half mile) away from the substation to limit the exposure of the phase conductors to direct strokes near the substation. Strokes occurring on the circuits beyond the shielding will usually be attenuated enough by the time they reach the substation to be discharged successfully by the surge arresters without causing equipment damage. For adequate protection, the circuit wire systems should be directly connected to the substation shield wire system.

4.7.3.3   Shielding Masts: Shielding masts can be used for nearly all types of substations to provide protection against direct lightning strokes. They are particularly useful in large substations and those of low-profile design. Shielding masts can be guyed or self-supporting steel poles or lattice-type towers and are usually made of steel. Other materials, such as precast concrete or aluminum, can also be used.

In some instances, shielding masts can also be used to provide support for substation lighting equipment.

4.7.3.4   Protection Calculation Methods: There are two widely used methods for designing substation lightning protection:

1.   Fixed angle
2.   Rolling sphere

The zone of protection of a shielding system is the volume of space inside which equipment is considered adequately protected by the system. A shielding system allowing no more that 0.1 percent of the total predicted number of lightning strokes to terminate on the protected equipment is considered adequate for most situations.

4.7.3.4.1   Fixed Angle Method: The fixed angle design method uses vertical angles to determine the number, position, and height of shielding masts and wires. The shaded areas in Figure 4-17 illustrate the zones of protection afforded by single- and double-mast or shield wire systems. For a single mast, the zone of protection consists of a cone. For a single shield wire, the zone of protection is a wedge. When two or more masts or shield wires are used, the zones of protection of each overlap to provide complete coverage. Figure 4-17 also lists the ranges of angles that have been used for various shielding systems.

ANGLE	RANGE	RECOMMENDED
A	20° TO 60°	30°
B	40° TO 60°	45°

SINGLE MAST OR SHIELD WIRE   TWO MASTS OR SHIELD WIRES
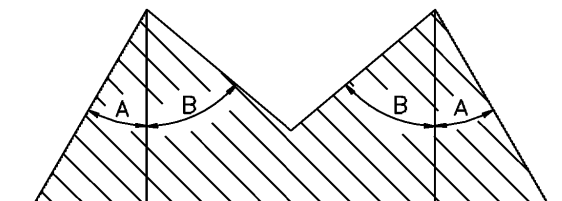
Figure 4-17: Zones of Protection for Masts and Shield Wires Using Fixed Angle Method

4.7.3.4.2   Rolling Sphere Method: The rolling sphere method involves rolling an imaginary sphere of a prescribed radius over the substation. The sphere rolls up and over (and is supported by) lightning masts, shield wires, and other grounded metal objects intended for lightning shielding. A piece of equipment is protected from a direct stroke if it remains below the curved surface of the sphere by virtue of the sphere's being elevated by shield wires or other devices. Equipment that touches the sphere or penetrates its surface is not protected. The basic concept is shown in Figure 4-18.
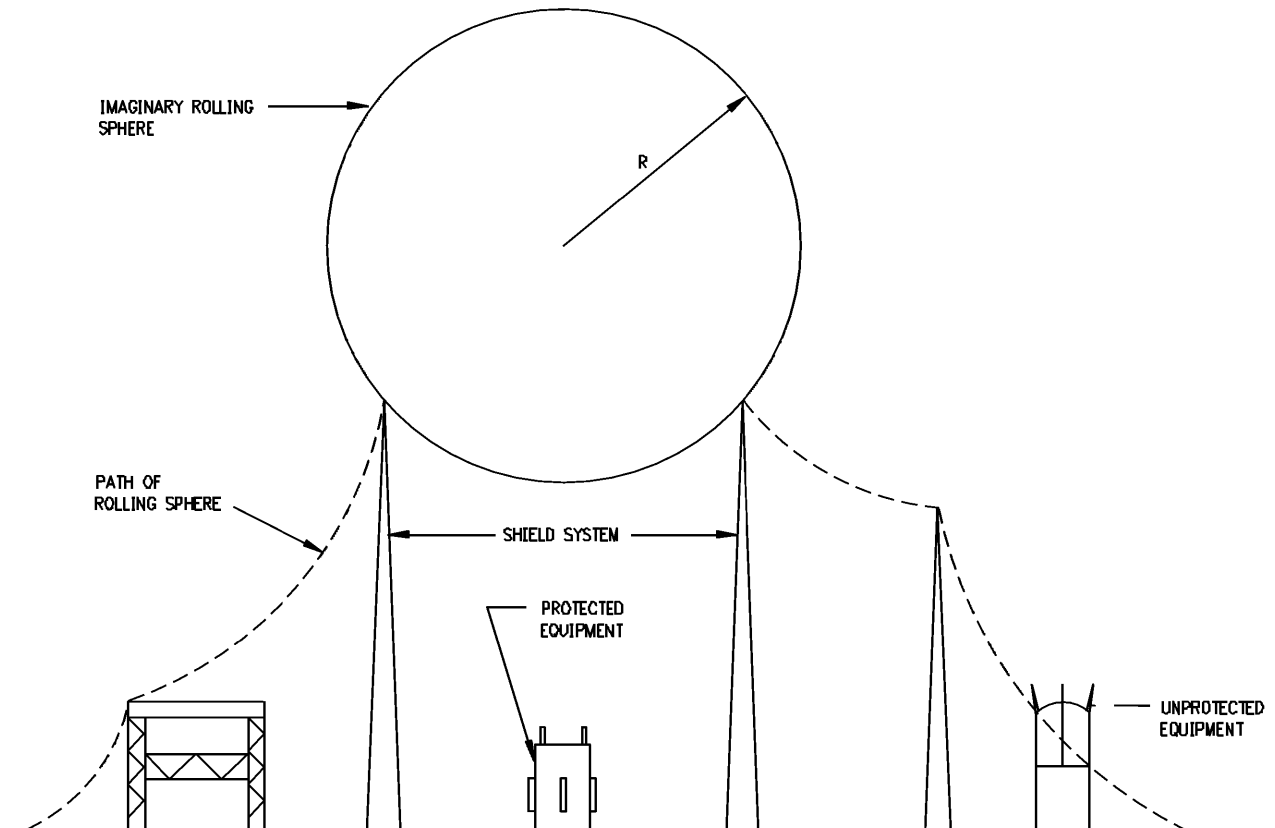
Figure 4-18: Principle of Rolling Sphere. Ref. IEEE Std. 998-1996, Fig. 7-3.
Copyright © 1996. IEEE. All rights reserved.

The radius of the sphere is determined by calculating the strike distance. The strike distance is the length of the final jump of the stepped leader as its potential exceeds the breakdown resistance of the last gap of air to ground. A stepped leader is the static discharge that propagates from a cloud into the air.

The allowable stroke current that may be received by a substation bus without exceeding the withstand value, or BIL, of the substation is defined by Equation 4-1:

Equation 4-1

$$I_s = \frac{2.2 * BIL}{Z_s}$$

Where:

I_s	=	Allowable stroke current in kiloamperes
BIL	=	Basic lightning impulse level in kilovolts
Z_s	=	Surge impedance of the conductor through which the surge is passing in ohms

Ref. IEEE Std. 998, Para. 5.2.2, Eq. 5-2A, and Definitions. Copyright © 1996. IEEE. All rights reserved.

The striking distance, indicated in Figure 4-18 by "R," may be calculated using Equation 4-2 or 4-3:

Equation 4-2

$$R_m = 8KI_s^{0.65}$$

or

Equation 4-3

$$R_f = 26.25KI_s^{0.65}$$

Where:

R_m	=	Strike distance in meters
R_f	=	Strike distance in feet
I_s	=	Return strike in kiloamperes
K	=	A coefficient to account for different striking distances to a mast, shield wire, or the ground plane. K = 1 for strokes to wires or the ground plane, and K = 1.2 for strokes to a lightning mast.

Ref. IEEE Std. 998, Para. 5.2.1, Eq. 5-1A, Eq. 5-1B, and Definitions. Copyright © 1996. IEEE. All rights reserved.

These equations provide a very basic evaluation of the lightning protection provided by the rolling sphere method. The many nuances and criteria on which the procedure is based are found in IEEE Std. 998, "Guide for Direct Lightning Stroke Shielding of Substations."

The engineer designing the shielding system needs to also take into account the isokeraunic level of the area where the substation will be built. The isokeraunic level is the average annual number of thunderstorm days for a given locality. The U.S. Weather Bureau publishes a chart that shows the isokeraunic levels across the United States.

For a complete description of both the fixed angle and the rolling sphere methods, refer to IEEE Std. 998, "Guide for Direct Lightning Stroke Shielding of Substations."

4.7.3.5   Shielding System Grounding: A shielding system cannot effectively protect substation equipment unless adequately grounded. Multiple low impedance connections from the shielding system to the substation ground grid are essential. It is beneficial to use at least two separate connections to ensure continuity and reliability. Whenever nonconducting masts or supports are used, install separate ground cables to establish a direct connection from the shield system to the substation ground system.

4.8 SUBSTATION INSULATORS

4.8.1 Outdoor Apparatus Insulators

4.8.1.1   Types: Outdoor apparatus insulators are used primarily to support rigid buswork and other electrical equipment operated above ground potential. Apparatus insulators are normally manufactured from electrical-grade wet-process porcelain and are available in two major types: cap and pin-type and post-type. Other types are also available from some insulator manufacturers.

4.8.1.2   BIL (Impulse Withstand) Ratings of Outdoor Apparatus Insulators : For apparatus insulators, impulse withstand voltages are commonly referred to as BILs. Apparatus insulators are available with BIL ratings as shown in Table 4-2. Use of the BILs for the nominal system voltages listed will normally ensure adequate coordination with protective devices and insulation systems of other equipment for most operating conditions. In areas of extremely high contamination, it may be desirable to increase the insulator BIL to levels higher than listed.

Table 4-2: Apparatus Insulator BIL Ratings for Nominal System Voltages.
Ref. NEMA SG-6-1995, Table 32-1. Reproduced with permission of the
National Electrical Manufacturers Association.

Nominal System Voltage kV	Apparatus Insulator BIL (Impulse Withstand) kV
7.5	95
14.4	110
23	150
34.5	200
46	250
69	350
115	550
138	650
161	750
230	900
230	1050
345	1050
345	1300

According to ANSI Std. C37.30, "Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports," equipment that depends on air for its insulating medium will have a lower dielectric strength when operated at higher altitudes than when operating at lower altitudes. For altitudes above 1000 meters (3300 feet), the correction factors shown in Table 4-3 should be applied to reduce the insulator BILs.

4.8.1.3   Cap and Pin-Type Outdoor Apparatus Insulators: Cap and pin-type (Cpt) apparatus insulators are the original insulator type used in substation construction. While Cpt is still in use, post-type insulators are more commonly used today in substation design and are recommended for any new construction or rebuilding of existing facilities.

4.8.1.4   Post-Type Outdoor Apparatus Insulators : Post-type apparatus insulators are the type most often used today for new substation construction. The uniform profile and smaller diameter enhance insulator appearance. Post insulator types in general use are made of porcelain and polymer. The polymer type is less rigid than porcelain or composite and is not recommended for switch supports.

Table 4-3: Altitude Correction Factors/BIL. Ref. ANSI/IEEE Std.
C37.30-1992, Table 1. Copyright © 1992. IEEE. All rights reserved.

Altitude Meters (feet)	Correction Factors to Be Applied to BIL
1000 (3300)	1.00
1200 (4000)	0.98
1500 (5000)	0.95
1800 (6000)	0.92
2100 (7000)	0.89
2400 (8000)	0.86
2700 (9000)	0.83
3000 (10,000)	0.80
3600 (12,000)	0.75
4200 (14,000)	0.70
4800 (16,000)	0.65
5400 (18,000)	0.61
6000 (20,000)	0.56

Note: Correction factors are currently being reviewed.

Porcelain insulators are generally manufactured from one piece of electrical-grade wet-process porcelain formed with a number of vertical skirts to achieve the required electrical characteristics. End caps for mounting the insulators are cemented to the porcelain. The insulators are manufactured with a minimum number of joints, which inherently reduces deflections.

The short skirts of post insulators make them less susceptible to damage from flashovers. Even if some of the skirts are damaged, insulation integrity is usually maintained since the dry arcing distances are not greatly affected.

Post-type insulators are available in two types: stacking and nonstacking. Single nonstacking insulators are normally used through nominal voltages of 69 kV (350 kV BIL). At nominal voltages of 115 kV (550 kV BIL) and above, stacking insulators are used. See Figure 4-19.

Since post-type insulators are available in different colors, preferences should be made known in advance of purchasing.

Post-type apparatus insulators are manufactured and tested in accordance with the following standards:

- ANSI C29.1   "Test Methods for Electrical Power Insulators"
- ANSI C29.9   "American National Standard for Wet-Process Porcelain Insulators (Apparatus, Post Type)"

4.8.1.5   Leakage Distance of Outdoor Apparatus Insulators: Post-type apparatus insulators depend on the insulating material contours to achieve the required leakage distances. Skirt breakage on a post type usually will not cause insulator flashover since a much smaller percentage of the total leakage distance is destroyed compared to the cap and pin type. Post-type apparatus insulators generally have longer leakage distances than their counterparts, particularly at the lower BILs.

In areas of high contamination it is usually desirable to utilize insulators with either longer than standard

Figure 4-19: Station Post Insulator. Courtesy of Lapp Insulator Co.

leakage distances or higher BILs to prevent electrical breakdown from surface contamination. Application of insulators in unusual situations such as high contamination can sometimes best be accomplished by referring the problem to the insulator manufacturers for recommendations.

4.8.1.6   Mechanical Strength of Outdoor Apparatus Insulators: Most apparatus insulators are available in several mechanical strength ratings, based primarily on the cantilever strength of the insulators. The various ratings available can be found in ANSI and NEMA standards and in manufacturers' literature.

For most applications, cantilever strength is the most important mechanical characteristic. However, depending on the actual insulator application, some of the other characteristics can become important and should be considered. These insulator characteristics include tensile strength, compressive strength, and torsional strength. The design and manufacture of post-type apparatus insulators allow equal cantilever strength ratings in both upright and underhung mounting positions.

Typical characteristics of cap and pin-type and post-type apparatus insulators can be found in Tables 4-4 and 4-5, respectively. Post insulators are recommended.

Table 4-4: Typical Characteristics of Cap and Pin-Type Insulators. Ref. Std. ANSI C29.8-1985, Table 1.
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BIL (IMPULSE WITHSTAND)	TECHNICAL REFERENCE	UPRIGHT CANTILEVER STRENGTH		UNDERHUNG CANTILEVER STRENGTH		BOLT CIRCLE		HEIGHT		LEAKAGE DISTANCE	
kV	NUMBER	POUNDS	(NEWTONS)	POUNDS	(NEWTONS)	IN.	(CM)	IN.	(CM)	IN.	(CM)
95	1	2,000	(8,896)	1,000	(4,448)	3	(7.62)	7.5	(19.1)	7.5	(19.1)
95	41	4,000	(17,792)	3,000	(13,344)	3	(7.62)	8	(20.3)	8	(20.3)
110	4	2,000	(8,896)	1,000	(4,448)	3	(7.62)	10	(25.4)	12.0	(30.5)
110	44	4,000	(17,792)	3,000	(13,344)	5	(12.7)	10	(25.4)	14.0	(35.6)
150	7	2,000	(8,896)	1,000	(4,448)	3	(7.62)	12	(30.5)	20.0	(50.8)
150	46	4,000	(17,792)	3,000	(13,344)	5	(12.7)	12	(30.5)	18.0	(45.7)
190	147	3,000	(13,344)	2,000	(8,896)	3	(7.62)	14.5	(36.8)	26.0	(66.0)
200	10	2,000	(8,896)	1,000	(4,448)	3	(7.62)	15	(38.1)	28.0	(71.1)
200	49	4,000	(17,792)	3,000	(13,344)	5	(12.7)	15	(38.1)	28.0	(71.1)
210	140	7,000	(31,136)	4,000	(17,792)	5	(12.7)	14.5	(36.8)	33.0	(83.8)
210	141	10,000	(44,480)	6,000	(26,688)	5	(12.7)	14.5	(36.8)	33.0	(83.8)
210	142	10,000	(44,480)	6,000	(26,688)	7	(17.8)	14.5	(36.8)	33.0	(83.8)
210	191	20,000	(88,960)	12,000	(53,376)	7	(17.8)	14.5	(36.8)	33.0	(83.8)
210	164	4,000	(17,792)	3,500	(15,568)	3	(7.62)	14.5	(36.8)	33.0	(83.8)
250	13	2,000	(8,896)	1,000	(4,448)	3	(7.62)	18	(45.7)	36.0	(91.4)
250	165	3,000	(13,344)	2,000	(8,896)	3	(7.62)	18	(45.7)	36.0	(91.4)
350	16	1,500	(6,672)	1,000	(4,448)	3	(7.62)	29	(73.7)	52.0	(132.0)
350	56	3,000	(13,344)	2,350	(10,453)	5	(12.7)	29.0 (1)	(73.7)	66.0	(168.0)
350	166	2,000	(8,896)	2,000	(8,896)	3	(7.62)	29.0 (1)	(73.7)	66.0	(168.0)
550	19	1,700	(7,562)	1,470	(6,539)	5	(12.7)	43.5 (1)	(111.0)	99.0	(252.0)
550	167	1,000	(4,448)	1,000	(4,448)	3	(7.62)	43.5 (1)	(111.0)	99.0	(252.0)
650	170	1,000	(4,448)	1,000	(4,448)	3	(7.62)	54.0 (1)	(137.2)	108.0	(274.3)
750	168	1,000	(4,448)	1,000	(4,448)	3	(7.62)	58.0 (1)	(147.3)	132.0	(335.3)
750	25	1,200	(5,338)	1,070	(4,759)	5	(12.7)	58.0 (1)	(147.0)	132.0	(335.0)
750	123	2,000	(8,896)	1,750	(7,784)	5	(12.7)	58.0 (1)	(147.0)	132.0	(335.0)
900	126	910	(4,048)	840	(3,736)	5	(12.7)	72.5 (1)	(184.0)	165.0	(419.0)
900	27	1,450	(6,450)	1,350	(6,005)	5	(12.7)	72.5 (1)	(184.0)	165.0	(419.0)
1050	128	750	(3,336)	700	(3,114)	5	(12.7)	87.0 (1)	(221.0)	198.0	(503.0)
1050	28	1,170	(5,204)	1,100	(4,893)	5	(12.7)	87.0 (1)	(221.0)	198.0	(503.0)
1050	196	2,300	(10,230)	2,300	(10,230)	7	(17.8)	87 (1)	(221.0)	198	(503.0)
1300	133	1,000	(4,448)	950	(4,226)	7	(17.8)	101.5 (1)	(257.8)	231	(586.7)
1300	197	2,000	(8,896)	2,000	(8,896)	7	(17.8)	101.5 (1)	(257.8)	231	(586.7)

Notes:
(1) Does not include 3.5-inch (8.89 cm) high sub-base that is required for full BIL.
(2) The insulators listed are representative of those currently available. Additional ratings are available for some voltages. Refer to manufacturers' data for information.
(3) The characteristics listed are typical. Refer to manufacturers' data for actual ratings and additional characteristics.

Table 4-5: Typical Characteristics of Post-Type Insulators. Ref. ANSI Std. C29.9-1983, Tables 1 and 2.
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BIL (IMPULSE WITHSTAND)	TECHNICAL REFERENCE	UPRIGHT CANTILEVER STRENGTH		UNDERHUNG CANTILEVER STRENGTH		BOLT CIRCLE							
						TOP		BOTTOM		HEIGHT		LEAKAGE DISTANCE	
kV	NUMBER	POUNDS	(NEWTONS)	POUNDS	(NEWTONS)	IN.	(CM)	IN.	(CM)	IN.	(CM)	IN.	(CM)
95	202	2000	(8896)	2000	(8896)	3	(7.62)	3	(7.62)	7.5	(19.1)	10.5	(26.7)
95	202	4000	(17792)	4000	(17792)	5	(12.7)	5	(12.7)	7.5	(19.1)	10.5	(26.7)
110	205	2000	(8896)	2000	(8896)	3	(7.62)	3	(7.62)	10	(25.4)	15.5	(39.4)
110	225	4000	(17792)	4000	(17792)	5	(12.7)	5	(12.7)	12	(30.5)	15.5	(39.4)
150	208	2000	(8896)	2000	(8896)	3	(7.62)	3	(7.62)	14	(35.6)	24	(61.0)
150	227	4000	(17792)	4000	(17792)	5	(12.7)	5	(12.7)	15	(38.1)	24	(61.0)
200	210	2000	(8896)	2000	(8896)	3	(7.62)	3	(7.62)	18	(45.7)	37	(94)
200	231	4000	(17792)	4000	(17792)	5	(12.7)	5	(12.7)	20	(50.8)	37	(94)
250	214	2000	(8896)	2000	(8896)	3	(7.62)	3	(7.62)	22	(55.9)	43	(109)
250	267	4000	(17792)	4000	(17792)	5	(12.7)	5	(12.7)	24	(61.0)	43	(109)
350	216	1500	(6672)	1500	(6672)	3	(7.62)	3	(7.62)	30	(76.2)	72	(183)
350	278	3000	(13344)	3000	(13344)	5	(12.7)	5	(12.7)	30	(76.2)	72	(183)
550	286	1700	(7562)	1700	(7562)	5	(12.7)	5	(12.7)	45	(114)	99	(251)
550	287	2600	(11564)	2600	(11564)	5	(12.7)	5	(12.7)	45	(114)	99	(251)
650	288	1400	(6227)	1400	(6227)	5	(12.7)	5	(12.7)	54	(137)	116	(295)
650	289	2200	(9786)	2200	(9786)	5	(12.7)	5	(12.7)	54	(137)	116	(295)
750	291	1200	(5338)	1200	(5338)	5	(12.7)	5	(12.7)	62	(157)	132	(335)
750	295	1850	(8229)	1850	(8229)	5	(12.7)	5	(12.7)	62	(157)	132	(335)
900	304	950	(4226)	950	(4226)	5	(12.7)	5	(12.7)	80	(203)	165	(419)
900	308	1450	(6450)	1450	(6450)	5	(12.7)	5	(12.7)	80	(203)	165	(419)
1050	312	800	(3558)	800	(3558)	5	(12.7)	5	(12.7)	92	(234)	198	(503)
1050	316	1250	(5560)	1250	(5560)	5	(12.7)	5	(12.7)	92	(234)	198	(503)
1050	362	2300	(10230)	2300	(10230)	7	(17.8)	7	(17.8)	92	(234)	198	(503)
1300	324	1000	(4448)	1000	(4448)	5	(12.7)	5	(12.7)	106	(269)	231	(587)
1300	367	1450	(6450)	1450	(6450)	5	(12.7)	7	(17.8)	106	(269)	231	(587)
1300	368	2000	(8896)	2000	(8896)	7	(17.8)	7	(17.8)	106	(269)	231	(587)
1300	369	2050	(9118)	2050	(9118)	5	(12.7)	7	(17.8)	106	(269)	231	(587)

Notes:

(1) The insulators listed are representative of those currently available. Additional ratings are available for some voltages. Refer to manufacturers' data for information.

(2) The characteristics listed are typical. Refer to manufacturers' data for actual ratings and additional characteristics.

4.8.1.7   Mounting Outdoor Apparatus Insulators : Most apparatus insulators are furnished with end caps with four mounting holes arranged in either 7.62-centimeter (3-inch), 12.7-centimeter (5-inch), or 17.8-centimeter (7-inch) bolt circles, or 30.5-centimeter (12-inch) or 35.6-centimeter (14-inch) bolt circles, depending on the insulator strength and voltage rating. The mounting holes are usually tapped for bolts of 1/2" with 13 threads per inch, 5/8" with 11 threads per inch, or 3/4" with 10 threads per inch, respectively. Adapters are available to go from one bolt circle size to another.

Upright or underhung mounting usually does not present major problems, provided the insulators are utilized within their mechanical and electrical capabilities. When the insulators are installed horizontally, the weight of the insulators, fittings, buses, and any other supported equipment have to be considered to determine the permissible loads. Some manufacturers recommend reducing the allowable loads from the tabulated values for horizontally mounted insulators. Unusual applications can be referred to the manufacturers for recommendations.

4.8.2   Suspension Insulators

4.8.2.1   Types: Suspension insulators are used as insulation and support for strain buses in substations. Suspension insulators are available in several forms to suit individual requirements. Distribution deadend-type suspension insulators can be used at distribution voltages for substation strain buses. Distribution deadend suspension insulators normally have clevis-type connections. Conventional suspension insulators are normally used for strain bus insulation at higher voltages and can be furnished with either clevis or ball and socket connections. The conventional suspension insulators most commonly used are 25.4 centimeters (10 inches) in diameter and 14.6 centimeters (5 ¾ inches) in length. Suspension insulators are manufactured out of porcelain, polymer, and glass. See Figure 4-20.

Suspension insulators acceptable for use on RUS-financed systems are listed in RUS IP 202-1.

4.8.2.2   Electrical Characteristics of Suspension Insulators. To achieve the necessary electrical characteristics, a number of suspension insulators are strung together in series. It is important to coordinate the insulation characteristics of suspension insulator strings with the insulation systems of other substation equipment and the characteristics of various insulation protective devices.

The quantity of suspension insulators chosen for a particular application should be large enough to prevent unnecessary flashovers. Overinsulation, however, can result in flashovers occurring from phase to phase rather than from phase to ground. Consequently, the quantity of insulators should be small enough that all flashovers occur to ground.

Table 4-6 lists the recommended minimum quantities of standard 14.6 x 25.4 cm (5 ¾ x 10 in.) suspension insulators for particular nominal system voltages and BILs. Additional insulators should be considered under the following conditions:

1. Above 1000 meters (3300 feet), the correction factors listed in Table 4-3 should be applied to the BILs and the insulator quantities correspondingly increased.
2. In areas of high contamination, it may be necessary to increase the insulator quantities or consider the use of specially designed equipment.
3. When deadending on steel structures, an additional insulator is typically added.
4. When installed at an angle other than vertical, one or two insulators should be added when the angle from vertical approaches 45 degrees and 90 degrees, respectively.

Figure 4-20: Suspension Insulator

Table 4-6: Minimum Quantity of Suspension Insulators

Nominal System Phase-to-Phase Voltage kV	BIL kV	Minimum Quantity of Suspension Insulators*
7.5	95	1
14.4	110	2
23	150	2
34.5	200	3
46	250	4
69	350	5
115	550	8
138	650	9
161	750	10
230	900	12
230	1050	14
345	1300	20

*For standard 14.6- x 25.4-centimeter (5 ¾- x 10-inch) suspension insulators.

4.8.2.3   Mechanical Strength of Suspension Insulators: Suspension insulators are tested and categorized with simultaneous mechanical-electrical strength ratings, as listed in RUS IP 202-1. These strength ratings are not the actual loads the insulators are designed to operate under, but represent ultimate strengths. The insulators also have proof test ratings specified in ANSI Std. C29.2 as one half the mechanical–electrical ratings. These ratings are the actual loads that the insulators have withstood during testing. The maximum suspension insulator loading should not exceed 40 percent of the mechanical–electrical strength ratings listed in RUS IP 202-1.

4.9 ELECTRICAL CLEARANCES

Table 4-7 lists the electrical clearances for outdoor substation construction. The values identified as minimums should be maintained or exceeded at all times. Phase-to-ground and phase-to-phase clearances should be coordinated to ensure that possible flashovers occur from phase to ground rather than from phase to phase.

Table 4-8 lists the phase spacing of various types of outdoor air switches. The minimum metal-to-metal clearances should be maintained at all times with the switches in the open position, closed position, or anywhere between the open and closed positions.

Table 4-7: Outdoor Electrical Substation Clearances. Ref. ANSI C37.32-1996, Table 5; NEMA SG-6-1995, Table 32-1.
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Nominal Phase-to-Phase Voltage kV	Maximum Phase-to-Phase Voltage kV	BIL kV	Minimum Metal - to-Metal for Rigid Conductors meters (inches)	Centerline-to-Centerline Phase Spacing for Rigid Buses meters (inches)	Minimum to Grounded Parts for Rigid Conductors meters (inches)	Minimum Between Bare Overhead Conductors and Ground for Personal Safety meters (feet) (3)	Minimum Between Bare Overhead Conductors and Roadways Inside Substation Enclosure meters (feet) (4)
7.5	8.3	95	0.178 (7)	0.457 (18)	0.152 (6)	2.44 (8)	6.10 (20)
14.4	15.5	110	0.305 (12)	0.610 (24)	0.178 (7)	2.74 (9)	6.40 (21)
23	25.8	150	0.381 (15)	0.762 (30)	0.254 (10)	3.05 (10)	6.71 (22)
34.5	38	200	0.457 (18)	0.914 (36)	0.330 (13)	3.05 (10)	6.71 (22)
46	48.3	250	0.533 (21)	1.22 (48)	0.432 (17)	3.05 (10)	6.71 (22)
69	72.5	350	0.787 (31)	1.52 (60)	0.635 (25)	3.35 (11)	7.01 (23)
115	121	550	1.35 (53)	2.13 (84)	1.07 (42)	3.66 (12)	7.62 (25)
138	145	650	1.60 (63)	2.44 (96)	1.27 (50)	3.96 (13)	7.62 (25)
161	169	750	1.83 (72)	2.74 (108)	1.47 (58)	4.27 (14)	7.92 (26)
230	242	900	2.26 (89)	3.35 (132)	1.80 (71)	4.57 (15)	8.23 (27)
230	242	1050	2.67 (105)	3.96 (156)	2.11 (83)	4.88 (16)	8.53 (28)
345	362	1050	2.67 (105)	3.96 (156)	2.13 (84)*	4.88 (16)	8.53 (28)
345	362	1300	3.02 (119)	4.43 (174)	2.64 (104)*	5.49 (18)	9.14 (30)

Notes: (1) Values listed are for altitudes of 1000 meters (3300 feet) or less. For higher altitudes, the altitude correction factors listed in Table 4-3 should be applied.
(2) This is the minimum clearance from the top of structure, equipment, or apparatus foundation to energized conductors.
(3) In no cases should the clearance from the top of a foundation to the bottom of equipment bushings or insulators of energized equipment or apparatus be less than 2.44 meters (8 feet).
(4) This dimension indicates the clearance required for truck traffic under the overhead line while maintaining ground clearance.
*   Ground clearance for voltages 362 kV and above is selected on the premise that, at this level, selection of the insulation depends on switching surge levels of the system. The values were selected from Table 1 of IEEE Transaction Paper T-72-131-6 (Vol. 5, page 1924), which is a report of the Transmission Substations Subcommittee. For additional switching surge values and ground clearances, refer to ANSI Std. C2.

Table 4-8: Phase Spacing of Outdoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 5.
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Nominal Phase-to-Phase Voltage kV	Maximum Phase-to-Phase Voltage kV	BIL kV	Minimum Metal-to-Metal for Air Switches meters (inches)	Centerline-to-Centerline Phase Spacing meters (inches)		
				Vertical Break Disconnect Switches	Side or Horizontal Break Disconnect Switches	All Horn Gap Switches
7.5	8.3	95	0.175 (7)	0.457 (18)	0.762 (30)	0.914 (36)
14.4	15.5	110	0.305 (12)	0.610 (24)	0.762 (30)	0.914 (36)
23	25.8	150	0.381 (15)	0.762 (30)	0.914 (36)	1.22 (48)
34.5	38	200	0.457 (18)	0.914 (36)	1.22 (48)	1.52 (60)
46	48.3	250	0.533 (21)	1.22 (48)	1.52 (60)	1.83 (72)
69	72.5	350	0.787 (31)	1.52 (60)	1.83 (72)	2.13 (84)
115	121	550	1.35 (53)	2.13 (84)	2.74 (108)	3.05 (120)
138	145	650	1.60 (63)	2.44 (96)	3.35 (132)	3.66 (144)
161	169	750	1.83 (72)	2.74 (108)	3.96 (156)	4.27 (168)
230	242	900	2.26 (89)	3.35 (132)	4.87 (192)	4.87 (192)
230	242	1050	2.67 (105)	3.96 (156)	5.50 (216)	5.50 (216)
345	362	1050	2.67 (105)	3.96 (156)	5.49 (216)	5.49 (216)
345	362	1300	3.02 (119)	4.43 (174)	— —	— —

Notes: (1) Values taken from ANSI C37.32 and NEMA SG6.
(2) Values listed are for altitudes of 1000 meters (3300 feet) or less. For higher altitudes, the altitude correction factors listed in Table 4-3 should be applied.

When nonrigid conductors are used for outdoor overhead substation buses, the movement of the conductors caused by temperature changes and wind and ice loads has to be considered. The usual practice is to increase the centerline-to-centerline bus spacing and the phase-to-ground clearances to compensate for these conditions. Increase the minimum metal-to-metal, bus centerline-to-centerline, and minimum ground clearances listed in Table 4-7 by at least 50 percent for nonrigid conductors. Check to ensure that the minimum metal-to-metal clearances listed in Tables 4-7 and 4-8 are maintained or exceeded at all times for all expected temperature and loading conditions. The movement of nonrigid conductors can also be calculated using the *NESC* conductor movement envelopes for line conductors.

In some locations, contamination from airborne particles necessitates increasing the minimum electrical clearances. Satisfactory operation can usually be obtained by using clearances one step above those normally used. In extremely contaminated locations, additional clearance may be required.

Since the dielectric strength of air-insulated equipment decreases with increasing altitude, the clearances listed in Table 4-7 have to be modified for use at altitudes above 1000 meters (3300 feet). To determine appropriate clearances for use above 1000 meters (3300 feet), first derate the standard BILs by applying the factors listed in Table 4-3. Then choose the clearances from Table 4-7 corresponding to the derated BILs selected. For example, at an altitude of 2400 meters (8000 feet), a maximum voltage of 121 kV is to be used. From Table 4-3, the standard BIL of 550 kV has to be derated by applying a multiplying factor of 0.86. Table 4-9 shows the effects of derating for 2400 meters (8000 feet):

Table 4-9: Effects of Derating
for 2400 Meters

Standard BILs kV	Derated BILs kV
550	473
650	559
750	645

A 650 kV BIL should be selected for use at 2400 meters (8000 feet) to provide a BIL equivalent to 550 kV at altitudes of 1000 meters (3300 feet) and below. The clearances to be used are those associated with the 650 kV standard BIL, as listed in Tables 4-7 and 4-8.

As an option to the above equipment selection, the engineer may evaluate the derated BIL in terms of the capability of surge arresters applied to the equipment to provide protection to the equipment. With applicable protective margins, surge arresters available today may be able to protect voltage-derated equipment without increasing the equipment BIL for compensation.

In addition to the electrical clearances previously described, it is necessary to provide adequate space for equipment maintenance. In arrangements where equipment such as power circuit breakers, reclosers, disconnect switches, power transformers, or other equipment has to be maintained while portions of adjacent equipment remain energized, provide sufficient space around the equipment to prevent accidental contact by maintenance personnel.

In arrangements with buses or equipment crossing over other buses and equipment, maintain adequate clearance between the adjacent buses and equipment for all operational conditions. Position power transformers and power circuit breakers to permit removal of any bushing. Locate switches and other equipment with externally moving parts to prevent infringement on the minimum clearances listed in Tables 4-7 and 4-8 during operation or when in any position. Also consider conductor, equipment, or support structure movement during heavily loaded or deformed conditions.

The clearances listed in Tables 4-7 and 4-8 are adequate for most situations and exceed the requirements of the *National Electrical Safety Code.* The clearances listed in the *NESC* have to be maintained or exceeded at all times.

Another clearance requirement is the location of the substation perimeter fence with respect to live parts within the substation. A safety clearance zone is required to keep someone outside the substation from sticking an object through the fence and coming in contact with live parts or getting close enough to cause a flashover to occur. Use Figure 4-21 to locate exposed live parts outside the safety clearance zone.

4.10 BARE CONDUCTORS

4.10.1 <u>Conductor Materials</u>

Copper and aluminum are the two major conductor materials used for substation buses and equipment connections. Both materials can be fabricated into various types of flexible or rigid conductors. The trend in substation construction is toward use of mostly aluminum conductors. Copper conductors are used principally for expansion of similar systems in existing substations.

The conductivity of aluminum is from 50 to 60 percent that of copper, depending on the aluminum alloy. Consequently, larger aluminum conductors are required to carry the same currents as copper conductors. The larger aluminum conductor diameters result in greater wind and ice loads but tend to minimize corona, which is more of a problem at higher voltages.

For the same ampacity, copper conductors weigh approximately twice as much as aluminum conductors. The higher copper conductor weights can result in more sag as compared with aluminum conductors for equal spans. To reduce the sag, it is usually necessary to increase the number of supports for rigid conductors or, in the case of flexible conductors, increase the tensions.

4.10.2 <u>Rigid Conductors</u>

Rigid electrical conductors are available in a variety of shapes and sizes to suit individual requirements. Some of the more commonly used shapes include flat bars, structural shapes, and tubes. Specific physical and electrical properties and application data can be obtained from the conductor manufacturers.

4.10.2.1 Flat Bars: Flat bars can be utilized for outdoor substation buses and are particularly suitable since they can be easily bent and joined. For high-current applications, a number of flat bars can be grouped together, leaving a small space between the bars to facilitate heat dissipation. The ampacity of a group of flat bars depends on whether the bars are arranged vertically or horizontally. The number of bars that can be grouped together is limited because of skin and proximity effects. Flat bars are usually limited to use at lower voltages because of corona.

Because of their inherent lack of rigidity, supports for flat bar buses are usually closely spaced to minimize the effects of meteorological loads and short-circuit forces.

4.10.2.2 Structural Shapes: The structural shape conductors that have been used in outdoor substation construction consist primarily of angle and channel types. The flat surfaces permit bolting directly to support insulators and provide convenient connection points. To increase ampacity, two angles or channels can be used. Special fittings are usually required for these configurations. The positioning and grouping of structural shapes have limitations similar to those of flat bars.
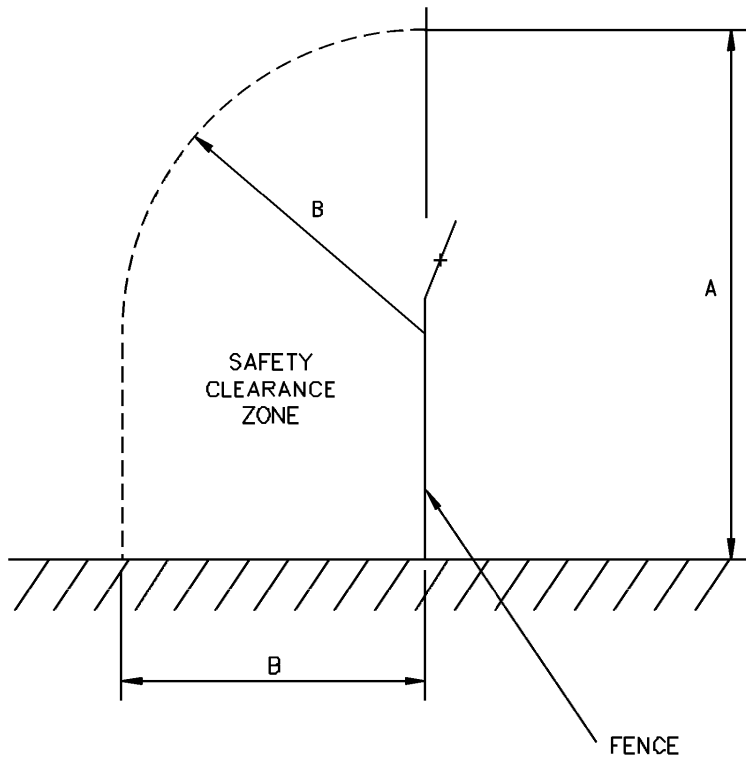
Dimensions for use with Figure 4-21, Fence Safety Clearance

Nominal Voltage Between Phases	Dimension A Ft	M	Dimension B Ft	M
151-34,500	15.0	4.6	10.0	3.1
46,000-69,000	16.0	4.9	12.0	3.7
115,000	16.7	5.1	13.0	4.0
138,000	17.1	5.2	14.0	4.3
161,000	17.6	5.4	14.0	4.3
230,000	19.0	5.8	16.0	4.9
345,000	21.3	6.5	18.0	5.5
500,000	24.9	7.6	21.0	6.4
765,000	29.7	9.1	23.0	7.0

NOTES:
1. Dimension A is equal to the vertical clearance of wires, conductors, and cables above spaces and ways subject to pedestrians or restricted traffic only (ANSI C2-1987 [1], Rules 232A and 232B, and Table 232-1, 5) for the voltage considered.
2. The B Dimension was established after considering the horizontal clearance of unguarded live parts in electric supply stations (ANSI C2-1987 [1], Rule 124 A, and Table 124-1), plus the effective length of a rod or pole that could be inserted through the electric supply station fence. The horizontal factors (ANSI C2-1987 [1], Table 124-1, Part C).
3. The values shown for Dimension A for nominal voltages between phases of 115,000 and above should be increased 3 percent for each 1000 ft (300 m) in excess of 3300 ft (1000 m) above mean sea level.

Figure 4-21: Safety Clearance to Electric Supply Station Fences.
Ref. IEEE Std. 119-1988, Fig. 1. Copyright © 1988. IEEE. All rights reserved.

The rigidity of both angle and channel shapes is somewhat higher than for flat bars of the same ampacity. Consequently, support spacing can usually be increased.

4.10.2.3 Tubular Shapes: Square and round tubular shapes are considerably more rigid than either flat bars or structural shapes of the same ampacity and permit longer spans. The flat surfaces of square tubes provide convenient connection and support points. To facilitate heat dissipation, ventilation holes are sometimes provided in the square tubes. Round tubular conductors are the most popular shape used in outdoor substation construction. The round shape is very efficient structurally and electrically and minimizes corona at higher voltages. The special fittings required for connecting, terminating, and supporting round tubular conductors are widely available.

4.10.2.4 Special Shapes: Special shapes combining the advantages of several of the standard shapes are also available. Integral web channel buses, uniform thickness angles, and other special configurations can be furnished.

4.10.2.5 Aluminum Alloys and Tempers: Aluminum conductors are available in a variety of alloys and tempers with different conductor conductivities and strengths. Round tubular conductors are usually specified as either 6061-T6 or 6063-T6 alloy. The 6063-T6 alloy has a conductivity approximately 23 percent higher and a minimum yield strength approximately 29 percent lower than the 6061-T6 alloy. Consequently, the 6063-T6 alloy can carry higher currents but may require shorter support intervals.

Both Schedule 40 and 80 pipe are available in either alloy. The Schedule 80 sizes have wall thicknesses approximately 40 percent thicker than the Schedule 40 sizes, resulting in lower deflections for equal span lengths.

Alloy 6106-T61 is frequently utilized for flat bars, structural shapes, and square tubes. Other alloys and tempers are available for special applications.

4.10.3 Flexible Conductors

Flexible electrical conductors can be used as substation buses and equipment taps. The conductors are normally cables fabricated by stranding a number of small conductors into one larger conductor. Stranding provides the required conductor flexibility while maintaining strength. The flexibility can be increased by reducing the diameter and increasing the quantity of individual conductors. Bare electrical cables for substation construction are usually concentric lay stranded with Class A or AA stranding in accordance with ASTM Std. B231.

Most flexible conductors used in substation construction consist of all copper, all aluminum, or aluminum with steel reinforcing (ACSR). The conductor type selected for a particular application is usually based on the span length, tension and tolerable sag, and cost. For long spans, large supporting structures will be required. The size and cost of these structures may depend on the conductor type and should be considered during the selection process.

Flexible conductors are available in many sizes. Size selection is based on ampacity, strength, weight, and diameter. Conductor diameter becomes increasingly important at higher voltages where corona can be a problem.

Data concerning the physical and electrical properties of the various wire types can be found in manufacturers' literature.

4.10.4 Conductor Ampacity

The ampacity of bare conductors is based on a number of factors, including the conductor material, proximity of the conductors, climatic conditions, conductor temperature rise, emissivity, and altitude.

Copper conductors can carry about 1.3 or more times as much current as aluminum conductors of the same size. However, based on weight, more than twice as much copper is required for the same ampacity.

The current distribution of closely spaced conductors is affected by their mutual inductance in accordance with the proximity effect. The additional losses attributed to this effect can usually be neglected if conductor spacing is 45.7 centimeters (18 inches) or greater.

Climatic conditions have a great effect on conductor ampacity. Ampacities are usually determined based on ambient temperatures of 40°C (104°F). For prolonged ambient temperatures above this value, ampacities are usually reduced. Wind tends to reduce the temperature of outdoor bare conductors. An assumed steady wind may be reasonable in many areas. The sun's radiation can cause the temperature of bare conductors to increase, which results in lower ampacities and should be considered in predominately sunny locations.

Conductor temperature rise is the temperature increase above ambient at which the conductor is operating. To prevent excessive surface oxidation and possible damage from annealing, the temperature rise is usually limited to 30°C (54°F) for a total maximum conductor temperature of 70°C (158°F) under normal operating conditions. The trend is toward higher operating temperatures. Temperature rises of 50°C (90°F) and higher have been used successfully. However, temperatures that could damage the conductors or connected equipment should be avoided.

The conductor surface emissivity has an effect on conductor ampacity. For aluminum conductors, emissivity is usually taken as 0.5 and for copper conductors 0.8. Both of these values are for heavily weathered conductor surfaces. The ampacity is usually higher for greater emissivity.

According to ANSI Std. C37.30, "Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports," equipment that depends on air for its cooling medium will have a higher temperature rise when operated at higher altitudes than when operating at lower altitudes. For altitudes in excess of 1000 meters (3300 feet), the correction factors listed in Table 4-10 should be applied. Consider a conductor with an ampacity of 1000 amperes in a 40°C (104°F) ambient temperature with a 30°C (54°F) temperature rise at an altitude of 1000 meters (3300 feet). If this conductor is to be used at a higher altitude, the ampacity has to be corrected. At 5400 meters (18,000 feet), this conductor will have an ampacity of 1000 x 0.910 = 910 amperes in an ambient temperature of 40°C (104°F) with a 30°F (54°F) temperature rise. The conductor may be operated at 1000 amperes at 5400 meters (18,000 feet), provided the ambient temperature does not exceed 40°C x 0.824 = 33°C (104°F x 0.824 = 85.7°F) and the temperature rise does not exceed 30°C (54°F).

4.10.5 Bus Connections

4.10.5.1 General: It is customary to purchase rigid bus conductors in lengths ranging from 3.05 meters (10 feet) to 12.2 meters (40 feet). Sections need to be joined together for longer lengths. Taps are required from buses to electrical equipment. Bus conductors need to be attached to support insulators. For greatest reliability and lowest cost, the fewer the connections the better.

Table 4-10: Altitude Correction Factors/Current. Ref. ANSI Std. C37.30-1992, Table 1.
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Altitude Meters (Feet)	Correction Factors to Be Applied to Current Rating*	Correction Factors to Be Applied to Ambient Temperature*
1000 (3300)	1.00	1.00
1200 (4000)	0.995	0.992
1500 (5000)	0.990	0.980
1800 (6000)	0.985	0.968
2100 (7000)	0.980	0.956
2400 (8000)	0.970	0.944
2700 (9000)	0.965	0.932
3000 (10,000)	0.960	0.920
3600 (12,000)	0.950	0.896
4200 (14,000)	0.935	0.872
4800 (16,000)	0.925	0.848
5400 (18,000)	0.910	0.824
6000 (20,000)	0.900	0.800

Note: Correction factors are currently being reviewed.
*The correction factors for current rating and ambient temperature should not be applied at the same time.

The various substation bus connections can be made by using any of four main methods—bolting, clamping, compressing, and welding—depending on the conductor type and material. Bolted connections are utilized in connecting two or more flat surfaces together. Clamp-type connections generally involve the use of special fittings fabricated to permit conductors to be joined together or connected to other equipment. Compression connections are principally used for splicing or terminating flexible conductors. Welded connections are used primarily with rigid aluminum conductors. Weldment fittings are available that eliminate extensive conductor cutting and shaping prior to welding. Compression fittings are now available for rigid tubular bus.

Whenever connectors are utilized for making electrical connections, they should be equivalent electrically and mechanically to the conductors themselves. Substation connectors are designed, manufactured, and tested in accordance with NEMA Std. CC1, "Electric Power Connectors for Substations."

4.10.5.1.1   Bolted Connections: Bolted connections are the primary means of making connections to equipment terminals. Bolted joints permit the disconnection of equipment for maintenance or replacement.

The most common bolted connection involves joining a conductor to an equipment terminal. A terminal lug is attached to the conductor by clamping, compressing, or welding, and the lug is bolted to the equipment terminal.

When a copper conductor is connected to a flat copper or electrical bronze equipment terminal, a copper or electrical bronze terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two ½-inch, 13 threads per inch, high-strength silicon bronze bolts normally torqued to 54.23 newton-meters (40 pound-feet). Silicon bronze flat washers are normally used under both the bolt heads and the nuts.

When an aluminum conductor is connected to a flat copper or electrical bronze equipment terminal, an aluminum terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two ½-inch, 13 threads per inch, anodized aluminum bolts normally torqued to 33.9 newton-meters (25 pound-feet). The bolts are usually aluminum alloy 2024-T4 and the nuts alloy 6061-T6. Flat washers of aluminum alloy 2024-T4 are normally used under both the bolt heads and the nuts. An anti-oxidation compound should also be considered for aluminum connections.

When a copper conductor is connected to a flat aluminum equipment terminal, a copper or electrical bronze terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two ½-inch, 13 threads per inch bolts, normally of stainless steel or tin-plated high-strength silicon bronze. Flat washers of the same material as the other hardware are used under both the bolt heads and the nuts. Stainless steel spring washers are used between the flat washers and the nuts. Bolts are torqued to the spring washer manufacturer's recommendations.

When an aluminum conductor is connected to a flat copper or electrical bronze equipment terminal, an aluminum terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two ½-inch, 13 threads per inch bolts, normally of stainless steel or tin-plated high-strength silicon bronze. Flat washers of the same material as the other hardware are used under both the bolt heads and nuts. Stainless steel spring washers are used between the flat washers and the nuts. Bolts are torqued to the spring washer manufacturer's recommendations.

For aluminum–copper connections, the copper component should be installed below the aluminum component to prevent the copper salts from washing onto the aluminum. Additionally, the aluminum component should be massive, compared with the copper component. It is recommended the copper connector be tinned when connecting to aluminum connectors.

4.10.5.1.2 Clamp-Type Connections: A large variety of clamp-type electrical connectors are available for both flexible and rigid conductors of copper and aluminum. Most clamp-type connectors achieve their holding ability as a result of tightening a number of bolts. The quantities and sizes of bolts used should be as listed in NEMA Std. CC1.

Copper or electrical bronze connectors should be utilized with copper conductors. All-aluminum connectors should be used with aluminum conductors.

4.10.5.1.3 Compression Connections: Compression connections are used in splicing or installing terminal lugs on flexible conductors and for round tubular aluminum conductors. All-aluminum compression connectors should be used for aluminum conductors. Copper compression connectors should be used for copper conductors.

For connection on flexible conductors, installation of compression connectors in a vertical position with the lug down should be avoided to prevent the entrance of moisture and possible damage from freezing. Compression connection on rigid or flexible conductors can be made under any weather condition. The fitting is compressed using a portable hydraulic pump. It compresses the fitting radially 360 degrees. An inspection gauge is then used to verify that the connection is acceptable.

Compression connectors should always be installed in strict accordance with the manufacturer's instructions concerning the quantity and location of compressions. Connectors designed for a minimum of two circumferential compressions are recommended.

4.10.5.2 Welded Connections: Welded connections are used primarily with round tubular aluminum conductors. Use of the special fittings available simplifies the procedures to permit faster installation. Properly made welded connections have resistances that are not appreciably higher than the conductors themselves to eliminate conductor hot spots.

Welded aluminum connections are extensively used in the construction of large substations. Construction costs are usually slightly less with welded than clamp-type connections. In smaller installations with fewer connections, it may not be economically feasible to weld connections.

4.11 RIGID BUS DESIGN

4.11.1 General Considerations

The design of a rigid bus system involves many factors.

4.11.1.1 Bus Location in the Substation and Its Proximity to Other Equipment: Provide ample clearance to permit equipment maintenance and removal. Situate the bus to allow entrance of construction and maintenance equipment into the substation.

4.11.1.2 Future Substation Expansion: It is important to plan for future expansion by sizing and positioning buses to facilitate modifications.

4.11.1.3 Conductor Selection: The bus conductors are selected based on ampacity, physical properties, and cost. Select conductors so that they have sufficient size and capacity to withstand system faults and overcurrents without damage from overheating.

4.11.1.4 Short-Circuit Conditions: During short circuits, large forces can be developed in the bus system. The rigid bus design includes consideration of these forces to prevent damage during short-circuit conditions. The bus centerline-to-centerline spacing and the short circuit current both have effects on these forces.

4.11.1.5 Wind and Ice Load: If not properly considered, wind and ice loads can cause extensive damage to bus conductors and insulators. The usual practice is to consider *National Electrical Safety Code* loadings as a minimum. Also consider local conditions since they may necessitate the use of more severe loading criteria.

4.11.1.6 Insulator Strength: Since the number of different insulator ratings is limited, exercise care in the bus layout so that a practical system is achieved. The strength of the insulators required is based on the total bus loading and particularly the short-circuit forces.

4.11.1.7 Conductor Sag: Limit the sag of the bus conductors in the design. A flat horizontal system looks much neater than one with excessive sag. The conductor sag is influenced by the conductor weight and section modulus, the span length, and the vertical loading.

4.11.1.8 Aeolian Vibration: Long conductor spans can be damaged by vibrations caused by winds. Excessive conductor sag can add to this problem. Span lengths whose natural frequency is near that set up by a wind that has a high recurrence should be avoided. Use dampering conductors or other devices in the bus to minimize vibration.

4.11.1.9   Conductor Expansion: As the temperature of the conductors increases, longitudinal expansion occurs. If the bus system is not provided with means to absorb this expansion, insulators or other connected equipment can be damaged. A wide temperature range is required to accommodate the bus length when de-energized at the lowest design temperature up to the maximum bus operating temperature.

4.11.1.10   Location of Conductor Couplers: Long buses usually require the use of more than one section of conductor. Consequently, couplers have to be utilized to join the sections together. These couplers have to be properly located to prevent damage from bus loading and short-circuit forces.

Plan the bus system carefully by considering these aspects and other factors as they may develop. This section deals with the design of the conductor and support insulator systems. For data concerning supporting structures, refer to Chapter 7.

4.11.2 Procedure for Rigid Bus Design

The following procedure can be used in designing a rigid bus system:

4.11.2.1 Material and Size Selection: Select the material and size of the bus conductors based on continuous current requirements. In higher voltage systems with longer bus spans, the structural capabilities of the conductors may be the factor that determines the conductor material and size. However, the conductors selected have to be capable of carrying the required continuous current in any case.

4.11.2.2 Spacing: Using Tables 4-7 and 4-8, determine the bus conductor centerline-to-centerline spacing.

4.11.2.3 Short-Circuit Forces: Calculate the maximum short circuit forces the bus has to withstand. These forces can be determined using Equation 4-4:

Equation 4-4

$$F_{SC} = 13.9 \times 10^{-5} \, K_{SC} \, \frac{i^2}{D} \qquad \left(F_{SC} = 37.4 \times 10^{-7} \, K_{SC} \, \frac{i^2}{D} \right)$$

Where:
F_{SC}	=	Maximum short-circuit force on center conductor for a three-phase flat bus configuration of round or square tubular conductors with the conductors equally spaced, in newtons per meter (pounds per foot)
K_{SC}	=	Short-circuit force reduction factor (0.5 to 1.0; 0.67 recommended)
i	=	rms value of three-phase symmetrical short-circuit current, in amperes
D	=	Centerline-to-centerline spacing of bus conductors in centimeters (inches)

4.11.2.4 Loading: Determine the total bus conductor loading. Table 4-11 lists values for wind and ice loading for the various loading districts defined in the *National Electrical Safety Code*. Consider these values as minimum. Also consider extreme wind.

Table 4-11: NESC Conductor Wind and Ice Loads.*
Ref. IEEE Std. C2-1997, Table 250-1. Copyright © 1997. IEEE. All rights reserved.

Load	Loading District		
	Heavy	Medium	Light
Radial thickness of ice in millimeters (inches)	12.5 (0.50)	6.5 (0.25)	0
Horizontal wind pressure in pascals (pounds per square foot)	190 (4.0)	190 (4.0)	430 (9.0)

*   Conductor loading is usually based on these criteria. However, in locations where more severe
     conditions are frequent, the conductor loading should be based on actual local conditions.

The ice loading can be determined using Equation 4-5:

Equation 4-5

$$W_I = 0.704\left(d_1^2 - d_2^2\right) \qquad \left(W_i = 0.311\left(d_1^2 - d_2^2\right)\right)$$

Where:
  W_I =   Ice loading, in newtons per meter (pounds per foot)
  d_1 =   Outside diameter of conductor with ice, in centimeters (inches) (determine ice thickness
               from Table 4-11)
  d_2 =   Outside diameter of conductor without ice, in centimeters (inches)

The wind loading can be determined using Equation 4-6:

Equation 4-6

$$F_W = 0.01 C_D P_W d_1 \qquad \left(F_W = 0.083 C_D P_W d_1\right)$$

Where:

  F_W =   Wind loading, in newtons per meter (pounds per foot)

  C_D =   Drag coefficient, see Figure 4-22

  P_W =   Wind pressure, in pascals (pounds per foot^2) (from Table 4-11)

  d_1 =   Outside diameter of conductor with ice, in centimeters (inches)

The total bus conductor loading can be determined using Equation 4-7:
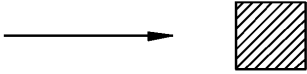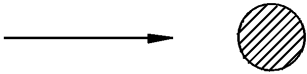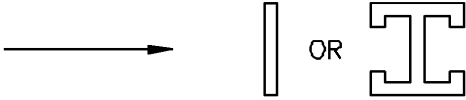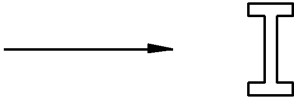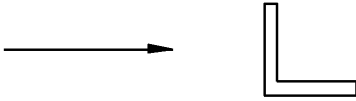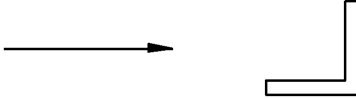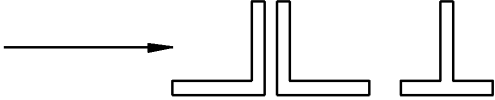
Equation 4-7

$$F_T = \left[\left(F_{SC} + F_W\right)^2 + \left(W_C + W_i\right)^2\right]^{1/2}$$

Where:
  F_T = Total bus conductor loading, in newtons per meter (pounds per foot)
  F_{SC} = Maximum short-circuit force, in newtons per meter (pounds per foot)
  F_W = Wind loading, in newtons per meter (pounds per foot)
  W_C = Conductor weight, in newtons per meter (pounds per foot) (if damping cables are used to
               control conductor vibration, add the cable weight to the conductor weight)
  W_I = Ice loading, in newtons per meter (pounds per foot)

$(\lambda \rightarrow \infty)*$

PROFILE AND WIND DIRECTION	c_D
⟶ ▨	2.03
⟶ ◍	1.00
⟶ | OR ⫛	2.00
⟶ I	2.04
⟶ L	2.00
⟶ ⌐|	1.83
⟶ ⊥⫿ ⊥	1.99

$*\lambda$ = RATIO OF SPAN LENGTH TO VERTICAL DIMENSION OF BUS CONDUCTOR

Figure 4-22: Drag Coefficients for Structural Shapes. Ref. ANSI/IEEE Std. 605-1987, Table 1.
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Equation 4-7 applies maximum wind and maximum ice at the same time. *NESC* and ANSI/IEEE Std. 605 apply these forces individually, which reduces F_T. Engineering judgment based on site conditions and design loads should determine the maximum loading conditions of the bus.

4.11.2.5 Span or Support Spacing: Calculate the maximum bus span or support spacing. Maximum bus support spacing can be determined using Equation 4-8:

Equation 4-8

$$L_M = K_{SM}\left(\frac{F_B S}{F_T}\right)^{1/2} \qquad \left(L_M = K_{SE}\left(\frac{F_B S}{F_T}\right)^{1/2}\right)$$

Where:

L_M = Maximum bus support spacing, in meters (feet)
K_{SM} = Multiplying factor from Table 4-12
K_{SE} = Multiplying factor from Table 4-12
F_B = Maximum desirable fiber stress of conductor, in kilopascals (pounds per inch^2)

For round tubular conductors of:

copper,

$F_B = 1.38 \times 105$ kPa $(20,000$ lb/in$^2)$*

6061-T6 aluminum alloy,

$F_B = 1.93 \times 105$ kPa $(28,000$ lb/in$^2)$*

6063-T6 aluminum alloy,

$F_B = 1.38 \times 105$ kPa $(20,000$ lb/in$^2)$*

*Includes a safety factor of 1.25.

S = Section modulus of conductor, in centimeters^3 (inches^3)
F_T = Total bus conductor loading, in newtons per meter (pounds per foot)

Table 4-12: Conductor Maximum Span and Deflection Multiplying Factors
(K_{SM}, K_{SE}, K_{DM}, K_{DE})

Bus System	K_{SM}	(K_{SE})	K_{DM}	(K_{DE})
Conductor fixed both ends (single span)	0.110	(1.0)	2.6×10^4	(4.50)
Conductor fixed one end, simply supported other end (single span)	0.090	(0.82)	5.4×10^4	(9.34)
Conductor simply supported (single span)	0.090	(0.82)	1.3×10^5	(22.5)
Conductor simply supported (two equal spans)*	0.090	(0.82)	5.4×10^4	(9.34)
Conductor simply supported (three or more equal spans)*	0.096	(0.88)	6.9×10^4	(11.9)

* Maximum deflection occurs in end spans.

4.11.2.6 Deflection: Calculate the maximum vertical conductor deflection using Equation 4-9:

Equation 4-9

$$y = K_{DM} \frac{(W_C + W_I)L^4}{EI} \qquad \left(y = K_{DE} \frac{(W_C + W_I)L^4}{EI} \right)$$

Where:

y	=	Maximum vertical conductor deflection, in centimeters (inches). (Limit this value to 1/200 of the span length. If the value calculated is greater than 1/200 of the span length, select a conductor with a larger diameter or reduce the span length. Recalculate as required.)
K_{DM}	=	Multiplying factor from Table 4-12
K_{DE}	=	Multiplying factor from Table 4-12
W_C	=	Conductor weight, in newtons per meter (pounds per foot) (if damping cables are used to control conductor vibration, add the cable weight to the conductor weight)
W_I	=	Ice loading, in newtons per meter (pounds per foot)
L	=	Bus support spacing, in meters (feet)
E	=	Modulus of elasticity, in kilopascals (pounds per inch^2)
I	=	Moment of inertia, in centimeters^4 (inches^4)

4.11.2.7 Cantilever Strength: Determine the minimum required support insulator cantilever strength using Equation 4-10:

Equation 4-10*
$$W_S = 2.5(F_{SC} + F_W)L_S$$

Where:

W_S	=	Minimum insulator cantilever strength, in newtons (pounds)
F_{SC}	=	Maximum short-circuit force, in newtons per meter (pounds per foot)
F_W	=	Wind loading, in newtons per meter (pounds per foot)
L_S	=	One half of the sum of the lengths of the two adjacent conductor spans, in meters (feet)

*Equation 4-10 includes an insulator safety factor of 2.5. This results in the insulator's working load being equal to 40 percent of the insulator's rated cantilever strength.

Select support insulators from Table 4-4 or 4-5 or from manufacturers' data with cantilever strength ratings equal to or greater than W_S. If sufficiently high ratings are not available, it will be necessary to modify the bus design. This can be done by increasing the centerline-to-centerline conductor spacing to reduce the short-circuit forces or by decreasing the bus span lengths.

4.11.2.8 Thermal Expansion: Provide for thermal expansion of conductors. The amount of conductor thermal expansion can be calculated using Equation 4-11:

Equation 4-11

$$\Delta \ell = \boldsymbol{a}\ell\Delta T$$

Where:

$\Delta\ell$	=	Conductor expansion, in centimeters (inches) (final length minus initial length)
α	=	Coefficient of linear thermal expansion:
		For aluminum, $\alpha = 2.3 \times 10^{-5}$ per degree Celsius (1.3×10^{-5} per degree Fahrenheit)
		For copper, $\alpha = 1.7 \times 10^{-5}$ per degree Celsius (9.2×10^{-6} per degree Fahrenheit)
ℓ	=	Initial conductor length, in centimeters (inches) (at initial temperature)
ΔT	=	Temperature variation, in degrees Celsius (Fahrenheit) (final temperature minus initial temperature)

Bus sections with both ends fixed without provision for conductor expansion should be avoided. Make connections to power circuit breakers, power transformers, voltage transformers, and other device bushings or terminals that could be damaged by conductor movement either with flexible conductors or expansion-type connectors.

Connections to switches utilizing apparatus insulators may require the use of expansion-type terminal connectors to prevent damage from excessive conductor expansion. Use of expansion-type terminals in this situation depends on the bus configuration and location of other expansion points. It is recommended that expansion fittings used on long horizontal buses be limited to those permitting longitudinal expansion only.

It is usually desirable to limit the length of sections of continuous buses to 30.48 meters (100 feet) or less to limit the amount of conductor expansion in each section. This can be done by fixing certain points in the bus and permitting other points to move freely. An example of a typical bus system is diagrammed in Figure 4-23.
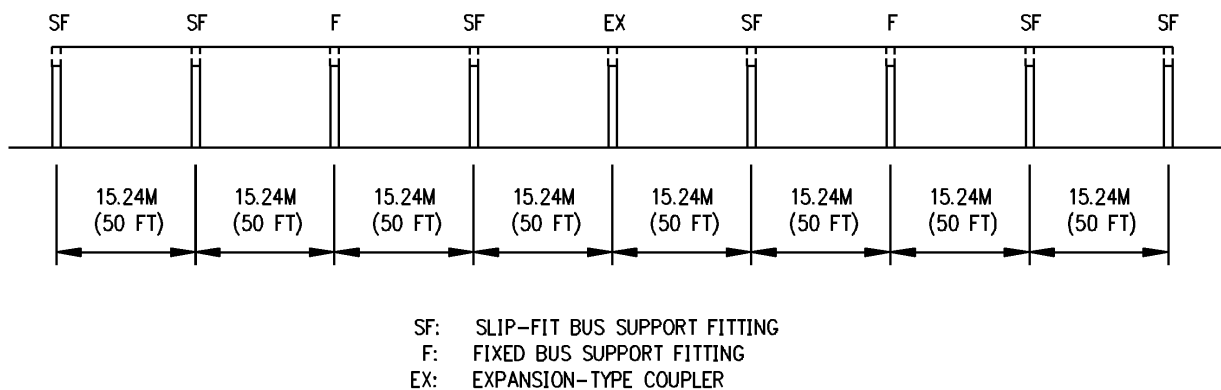
Figure 4-23: Typical Bus System Illustrating Provisions for Conductor Thermal Expansion

The system illustrated in Figure 4-23 can freely expand as necessary and is free of "captured spans" that permit no expansion. The locations of slip-fit and fixed bus supports and expansion-type couplers or bus supports divide the bus into four sections, each of which will expand approximately the same total

amount. If it is desirable to connect the end sections of the bus to other equipment, provide flexible conductors or expansion-type connectors.

4.11.2.9 Couplers: Locate conductor couplers. The couplers used on rigid buses should be as long as possible to provide maximum joint rigidity and strength. Clamp-type bolted couplers should have the quantity and size of clamping bolts listed in NEMA Std. CC1. Welded couplers for aluminum conductors should be of the internal type. Compression connectors should be appropriately sized and located.

To prevent conductor damage from bending caused by its own weight and external loads, carefully position couplers. Welding and bolting can cause appreciable loss of conductor strength in the immediate coupler locations. Consequently, position couplers where the least amount of bending will occur. The ideal locations are points of zero bending moment along the conductor.

Table 4-13 lists the ideal locations for conductor couplers for continuous conductors.

Table 4-13: Ideal Locations for Couplers in Continuous Uniformly Loaded Rigid Conductors

Quantity of Conductor Spans	Ideal Coupler Locations Measured to the Right from the Left-most Support
1	*
2	0.750L, 1.250L
3	0.800L, 1.276L, 1.724L, 2.200L
4	0.786L, 1.266L, 1.806L, 2.194L 2.734L, 3.214L
5	0.789L, 1.268L, 1.783L, 2.196L, 2.804L, 3.217L, 3.732L, 4.211L
6	0.788L, 1.268L, 1.790L, 2.196L, 2.785L, 3.215L, 3.804L, 4.210L, 4.732L, 5.212L

L   =   Distance of the bus between the bus supports.
*   The zero moment locations for single-span simply supported conductors are at the supports. Consequently, couplers are not recommended.

If couplers have to be positioned in other than the ideal locations listed in Table 4-13, reduce the maximum allowable fiber stress used in Section 4.11.2.5 by as much as 50 percent, depending on the degree of variation from the ideal location, and recalculate the maximum span length used. If the span length being considered exceeds this maximum, reduce it as necessary. Conductor couplers can now be positioned wherever convenient.

4.11.2.10 Aeolian Conductor Vibration: Aeolian conductor vibration is primarily the result of steady low-velocity transverse winds striking the conductor and causing it to vibrate. When the frequency of the driving force (wind) is approximately equal to the natural frequency of the bus span, resonance occurs. The resulting vibrations can cause insulator damage.

Vibrations will occur in almost all bus spans independently of the conductor material, diameter, or length. In short spans, the vibrations are usually of small enough magnitude to be neglected. However, in spans longer than about 6 meters (20 feet), methods for vibration damping should be considered.

Two primary methods have been used to dampen aeolian vibrations. The first and most widely used method consists of installing scrap cables in the horizontal buses. When this method is used, it is necessary that the cables be loose in the bus tubing to permit vertical movement. If new cables are used, they should be straightened prior to installation to prevent the cables from jamming against the tubing sides. Additionally, end caps, preferably of the driven type, should be installed on the ends of the buses containing the damping cables to prevent horizontal cable movement out of the tubing. To be effective, damping cables should be installed for the entire bus length for buses where excessive vibration is suspected.

The second method used to dampen aeolian vibrations consists of installing internal or external prefabricated bus dampers on the bus conductors. Usually, one damper is installed in each bus span to control the vibrations. Location and installation should be in accordance with the manufacturer's instructions.

4.11.3 Bus Design Example

Design a three-phase rigid bus with the following characteristics:

Total bus length:	45.72 meters (150 feet), assuming four equal spans of 11.43 m (37.5 ft)
Voltage:	161 kV
BIL:	750 kV
Insulator type:	post
Continuous current rating:	1800 amperes
Short-circuit current:	24,000 rms symmetrical amperes
Altitude:	304.8 m (1000 ft)
NESC loading:	heavy
Disconnect switch connected to one end of bus	
External prefabricated dampers to control conductor vibration	

4.11.3.1 Material and Size Selection: Select the material and size of the bus conductors.

Based on the continuous current requirements, 7.6 cm (3 in.) IPS, schedule 40 6063-T6 aluminum alloy (1890 amperes) is selected with the following properties:

W_C (weight) = 38.2 N/m (2.62 lb/ft)*; see Table 4-14

d_2 (outside diameter) = 8.89 centimeters (3.50 inches); see Table 4-14

I (moment of inertia) = 125.6 cm^4 (3.017 in^4); see Table 4-14

E (modulus of elasticity) = 6.9 x 10^7 kPa (10 x 10^6 lb/in^2)

S (section modulus) = 28.2 cm^3 (1.72 in^3); see Table 4-14

F_B (maximum allowable fiber stress) = 1.38 x 10^5 kPa (20,000 lb/in^2)

* If damping cables are to be used to control conductor vibration, the cable weight has to be added to the conductor weight. In this example, external prefabricated dampers will be used for vibration control.

Table 4-14: ASA Schedule 40 Aluminum Pipe Conductors Physical Properties. Hubbell Technical Data, Table 52.
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NOMINAL PIPE SIZE		DIAMETER				WALL THICKNESS		AREA		WT/FT	WT/M	MOMENT OF INERTIA		SECTION MODULUS		RADIUS OF GYRATION	
		IN.		CM													
IN.	CM	OUTSIDE	INSIDE	OUTSIDE	INSIDE	IN.	CM	IN.^{2}	CM^2	LB	N/M	IN.^{4}	CM^4	IN.^{3}	CM^3	IN.	CM
½	1.27	0.840	0.622	2.134	1.580	0.109	0.277	0.250	1.615	0.294	4.290	0.017	0.712	0.041	0.667	0.261	0.664
¾	1.91	1.050	0.824	2.667	2.093	0.113	0.287	0.333	2.146	0.391	5.706	0.037	1.540	0.071	1.155	0.334	0.848
1	2.54	1.315	1.049	3.340	2.664	0.133	0.338	0.494	3.186	0.581	8.479	0.087	3.634	0.133	2.176	0.421	1.068
1 ¼	3.18	1.660	1.380	4.216	3.505	1.140	2.896	0.669	4.313	0.786	11.470	0.195	8.104	0.235	3.844	0.540	1.371
1 ½	3.81	1.900	1.610	4.826	4.089	1.145	2.908	0.800	5.158	0.940	13.718	0.310	12.899	0.326	5.345	0.623	1.581
2	5.08	2.375	2.067	6.033	5.250	0.154	0.391	1.075	6.932	1.264	18.446	0.666	27.709	0.561	9.187	0.787	1.999
2 ½	6.35	2.875	2.469	7.303	6.271	0.203	0.516	1.704	10.994	2.004	29.245	1.530	63.683	1.064	17.436	0.947	2.406
3	7.62	3.500	3.068	8.890	7.793	0.216	0.549	2.229	14.377	2.621	38.249	3.017	125.577	1.724	28.251	1.164	2.957
3 ½	8.89	4.000	3.548	10.160	9.012	0.226	0.574	2.680	17.287	3.151	45.983	4.788	199.292	2.394	39.231	1.337	3.396
4	10.16	4.500	4.026	11.430	10.226	0.237	0.602	3.174	20.477	3.733	54.476	7.232	301.019	3.214	52.668	1.510	3.835
5	12.70	5.563	5.047	14.130	12.819	0.258	0.655	4.300	27.741	5.057	73.798	15.160	631.007	5.451	89.326	1.878	4.770
6	15.24	6.625	6.065	16.828	15.405	0.280	0.711	5.581	36.009	6.564	95.790	28.150	1171.691	8.498	139.257	2.245	5.702

4.11.3.2 Spacing: Determine the bus conductor centerline-to-centerline spacing from Table 4-7:

D (bus centerline-to-centerline spacing) = 274 cm (108 in.)

4.11.3.3 Short-Circuit Forces: Calculate the maximum short circuit force:

$$F_{SC} = 13.9 \times 10^{-5} K_{SC} \frac{i^2}{D} \qquad \left(F_{SC} = 37.4 \times 10^{-7} K_{SC} \frac{i^2}{D} \right)$$

$$F_{SC} = \left(13.9 \times 10^{-5} \right) \left(0.67 \right) \left(\frac{24{,}000}{274} \right)^2 \qquad \left(F_{SC} = \left(37.4 \times 10^{-7} \right) \left(0.67 \right) \left(\frac{24{,}000}{108} \right)^2 \right)$$

$$F_{SC} = 195.8 \text{ N/m}$$

$$\left(F_{SC} = 13.4 \text{ lb/ft}^2 \right)$$

4.11.3.4 Loading: Determine the total bus conductor loading:

From Table 4-9, Radial thickness of ice: 1.27 cm (0.50 in.)

Horizontal wind pressure: 191.5 Pa (4.0 lb/ft²)

$$W_I = 0.704 \left(d_1^2 - d_2^2 \right) \qquad \left(W_I = 0.311 \left(d_1^2 - d_2^2 \right) \right)$$

$$W_I = \left(0.704 \right) \left[\left(11.43 \right)^2 - \left(8.89 \right)^2 \right] \qquad \left(W_I = 0.311 \left[\left(4.50 \right)^2 - \left(3.50 \right)^2 \right] \right)$$

$$W_I = 36.3 \text{ N/m} \qquad \left(W_I = 2.49 \text{ lb/ft} \right)$$

$$F_W = 0.01 \, P_W d_1 \qquad \left(F_W = 0.083 \, P_W d_1 \right)$$

$$F_W = \left(0.01 \right) \left(191.5 \right) \left(11.43 \right) \qquad \left(F_W = \left(0.083 \right) \left(4.0 \right) \left(4.50 \right) \right)$$

$$F_W = 21.9 \text{ N/m} \qquad \left(F_W = 1.49 \text{ lb/ft} \right)$$

$$F_T = \left[\left(F_{SC} + F_W \right)^2 + \left(W_C + W_I \right)^2 \right]^{\frac{1}{2}} \qquad \left(F_T = \left[\left(F_{SC} + F_W \right)^2 + \left(W_C + W_I \right)^2 \right]^{\frac{1}{2}} \right)$$

$$F_T = \left[\left(195.8 + 21.9 \right)^2 + \left(38.2 + 36.3 \right)^2 \right]^{\frac{1}{2}} \qquad \left(F_T = \left[\left(13.3 + 1.49 \right)^2 + \left(2.62 + 2.49 \right)^2 \right]^{\frac{1}{2}} \right)$$

$$F_T = 230.1 \text{ N/m} \qquad \left(F_T = 15.6 \text{ lb/ft} \right)$$

4.11.3.5 Support Spacing: Calculate the maximum bus support spacing:

$$L_M = K_{SM} \left[\frac{F_B S}{F_T} \right]^{\frac{1}{2}} \qquad \left(L_M = K_{SE} \left[\frac{F_B S}{F_T} \right]^{\frac{1}{2}} \right)$$

Four equal spans of 11.43 meters (37.5 feet) were assumed. From Table 4-12, $K_{SM} = 0.096$ ($K_{SE} = 0.88$) for three or more equal spans.

$$L_M = (0.096)\left[\frac{(1.38 \times 10^5)(28.2)}{230.1}\right]^{1/2} \qquad \left(L_M = (0.88)\left[\frac{(20,000)(1.72)}{(15.6)}\right]^{1/2}\right)$$

$$L_M = 12.48\,m \qquad\qquad (L_M = 41.3\,ft)$$

The assumed spacing of 11.43 meters (37.5 ft) is structurally permissible for the conductors.

4.11.3.6 Deflection: Calculate the maximum vertical conductor deflection:

$$y = K_{DM}\,\frac{(W_C + W_I)L^4}{EI} \qquad \left(y = K_{DE}\,\frac{(W_C + W_I)L^4}{EI}\right)$$

Four equal spans of 11.43 meters (37.5 feet) were assumed. From Table 4-12, $K_{DM} = 6.9 \times 10^4$ ($K_{DE} = 11.9$) for three or more equal spans.

$$y = (6.9 \times 10^4)\,\frac{(38.2 + 36.3)(11.43)^4}{(6.9 \times 10^7)(125.6)} \qquad \left(y = (11.9)\frac{(2.62 + 2.49)(37.5)^4}{(10 \times 10^6)(3.017)}\right)$$

$$y = 10.1\ cm \qquad\qquad (y = 3.99\ in.)$$

Maximum permissible deflection is 1/200 of the span length:

$$y_{max} = \frac{(11.43)(100)}{200} \qquad \left(y_{max} = \frac{(37.5)(12)}{200}\right)$$

$$y = 5.72\ cm \qquad\qquad (y_{max} = 2.25\ in.)$$

Since the calculated deflection is greater than the maximum permissible deflection, the design has to be modified. The span length will be reduced to five equal spans of 9.14 meters (30 feet) each. The maximum vertical deflection is then recalculated.:

$$y = (6.9 \times 10^4)\,\frac{(38.2 + 36.3)(9.14)^4}{(6.9 \times 10^7)(125.6)} \qquad \left(y = (11.9)\frac{(2.62 + 2.49)(30)^4}{(10 \times 10^6)(3.017)}\right)$$

$$y = 4.14\ cm \qquad\qquad (y = 1.63\ in.)$$

Maximum permissible deflection is:

$$y_{max} = \frac{(9.14)(100)}{200} \qquad \left(y_{max} = \frac{(30)(12)}{200}\right)$$

$$y_{max} = 4.57\ cm \qquad\qquad (y_{max} = 1.80\ in.)$$

Since the calculated value with 9.14 m (30 ft) support spacing is less than the maximum permissible deflection, this support spacing is adequate.

4.11.3.7 Cantilever Strength: Determine the minimum required support insulator cantilever strength:

$$W_S = 2.5(F_{SC} + F_W)L_S \qquad\qquad (W_S = 2.5(F_{SC} + F_W)L_S)$$

$$W_S = (2.5)(195.8 + 21.9)\left(\frac{9.14}{2} + \frac{9.14}{2}\right) \qquad \left(W_S = 2.5(13.3 + 1.49)\left(\frac{30}{2} + \frac{30}{2}\right)\right)$$

$$W_S = 4974\,\text{N} \qquad\qquad (W_S = 1109\,\text{lb})$$

From Table 4-5, select Technical Reference Number 291 for 5338 newtons (1200 pounds) cantilever strength post type insulators.

4.11.3.8 Thermal Expansion: Provide for conductor expansion:

Assuming a total conductor temperature variation of 50°C (90°F), the total conductor expansion is:

$$\Delta\ell = a\ell\Delta T \qquad\qquad (\Delta\ell = a\ell\Delta T)$$

$$\Delta\ell = (2.3\times10^{-5})(45.72)(100)(50) \qquad (\Delta\ell = (1.3\times10^{-5})(150)(12)(90))$$

$$\Delta\ell = 5.26\,\text{cm} \qquad\qquad (\Delta\ell = 2.11\,\text{in.})$$

Some means has to be provided to account for this change. Figure 4-24 illustrates one method that can be used that permits free expansion in all spans.
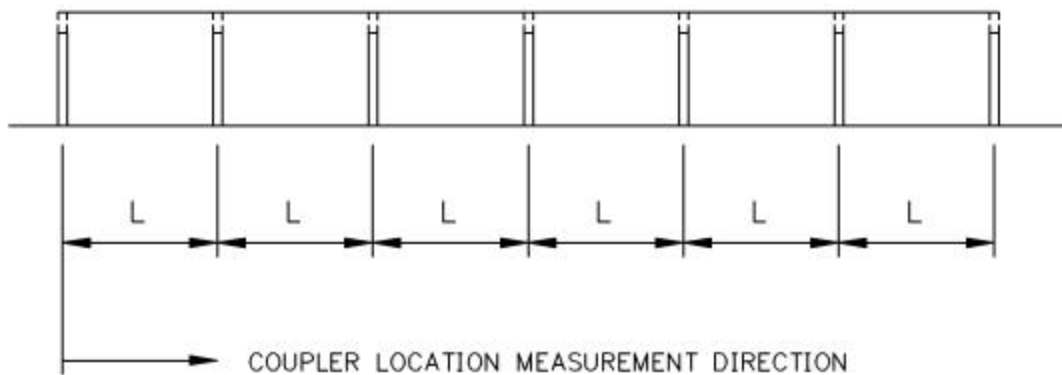
Figure 4-24: Coupler Location

4.11.3.9 Couplers: Locate conductor couplers:

From Table 4-13, the ideal coupler locations for the five-span bus of 9.14-meter (30-foot) spans measured to the right from the left-most support are as follows:

1	7.2 m	(23.7 ft)
2	11.6 m	(38.0 ft)
3	16.3 m	(53.5 ft)
4	20.1 m	(65.9 ft)
5	25.6 m	(84.1 ft)
6	29.4 m	(96.5 ft)
7	34.1 m	(112.0 ft)
8	38.5 m	(126.3 ft)

These locations are illustrated in Figure 4-25. Assuming that the bus conductor is available in 12.19-meter (40-foot) lengths, the couplers should be positioned at points 2, 4, 6, and 8. The conductor lengths are cut as required to position the couplers at these approximate locations.
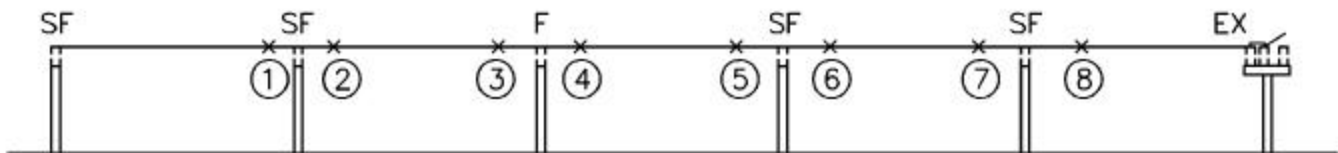
Legend:
    SF   =   Slip-fit bus support
    F   =   Fixed bus support
    EX   =   Expansion terminal

Figure 4-25: Bus Configuration for Example

4.11.3.10   Aeolian Vibration: Since the spans are fairly long, damaging vibrations may occur. Consequently, a means for controlling the vibrations should be provided. Prefabricated dampers can be attached to the buses or scrap cables can be installed in the buses. If cables are used, the cable weight has to be added to the conductor weight for the bus calculations.

4.12 STRAIN BUS DESIGN

4.12.1 General Considerations

Strain bus design involves many factors.

4.12.1.1 Bus Location in the Substation and Its Proximity to Other Equipment: The flexible conductors used for strain bus construction permit significant conductor movement. Consequently, the conductors have to be carefully positioned to prevent contact with other equipment and infringement upon minimum electrical clearances under all loading and climatic conditions. Equipment maintenance and removal should also be considered in locating buses and support structures.

4.12.1.2 Future Substation Expansion: Strain buses usually require large supporting structures. These structures can limit future expansion if not properly positioned.

4.12.1.3 Conductor Selection: The conductor is selected based on ampacity, physical properties, and cost. Conductors have to be selected so that they have sufficient size and capacity to withstand system faults and overcurrents without damage from overheating.

4.12.1.4 Wind and Ice Load: Wind and ice can increase conductor sags and tensions appreciably. The usual practice is to consider *National Electrical Safety Code* loadings as a minimum. Local conditions should be considered since they may necessitate the use of more severe loading criteria.

4.12.1.5 Insulator Strength: The suspension insulators are selected based on the anticipated maximum loading conditions. The maximum loading for porcelain insulators should not exceed 40 percent of the mechanical–electrical strength ratings listed in RUS IP 202-1. The maximum loading for fiberglass insulators may not exceed 40 percent of the manufacturer's strength ratings.

4.12.1.6 Span Length: The span length influences the conductor sag. As the span length increases, the sag increases if the same tension is maintained. To limit the sag, the tensions can be increased. Springs can also be used to limit the tension and sag.

4.12.1.7 Sag and Tension: Strain buses are usually positioned above other substation equipment. Conductor breakage could result in equipment damage or outage. To prevent breakage and to minimize support structure size, the conductors are usually installed at tensions of approximately 13,350 newtons (3000 pounds) or less. Sag may increase because of the deflection of support structures.

4.12.1.8 Temperature Variations: Temperature variations cause changes in conductor lengths. As conductor temperature increases, the sag increases and the tension decreases.

4.12.1.9 Tap Loads: Taps from the conductors to other buses or equipment should be limited in tension to prevent damage to equipment. The taps are usually installed as slack connections.

4.12.2 Procedure for Strain Bus Design

The following procedure can be used to design a strain bus system:

4.12.2.1 Material and Size Selection: Select the material and size of the bus conductors, based on continuous current requirements.

4.12.2.2 Spacing: Using Tables 4-7 and 4-8 from Section 4.9, determine the bus conductor centerline-to-centerline spacing. As explained in Section 4.9, the minimum metal-to-metal, bus centerline-to-centerline, and minimum ground clearances listed in Table 4-7 should be increased at least 50 percent for nonrigid conductors.

4.12.2.3 Suspension Insulators: Select the quantity of suspension insulators from Table 4-6.

4.12.2.4 Loading: Determine the total bus conductor loading. Table 4-15 lists values for wind and ice loading for the various loading districts defined in the *National Electrical Safety Code*. These values should be considered as minimum.

Table 4-15: NESC Conductor Loading Criteria.* Ref. ANSI Std. C2-1997, Tables 250-1 and 251-1.
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| Load | Loading District | | |
	Heavy	Medium	Light
Radial thickness of ice in millimeters (inches)	12.5 (0.50)	6.5 (0.25)	0
Horizontal wind pressure in pascals (pounds per square foot)	190 (4.0)	190 (4.0)	430 (9.0)
Temperature in degrees Celsius (degrees Fahrenheit)	–20 (0)	–10 (+15)	-1.0 (+30)
Constant (k) to be added to the resultant	4.4 (0.30)	2.5 (0.20)	0.73 (0.05)

*   Conductor loading is usually based on these criteria. However, in locations where more severe
conditions frequently occur, the conductor loading should be based on actual local conditions.

The ice loading can be determined from Equation 4-12:

Equation 4-12

$$W_I = 0.704 \left(d_1^2 - d_2^2 \right) \qquad \left(W_I = 0.311 \left(d_1^2 - d_2^2 \right) \right)$$

Where:

W_I = Ice loading, in newtons per meter (pounds per foot)

d_1 = Outside diameter of conductor with ice, in centimeters (inches) (determine ice thickness from Table 4-15)

d_2 = Outside diameter of conductor without ice, in centimeters (inches)

The wind loading can be determined using Equation 4-13:

Equation 4-13

$$F_W = 0.01 P_W d_1 \qquad \left(F_W = 0.083 P_W d_1 \right)$$

Where:

F_W = Wind loading, in newtons per meter (pounds per foot)

P_W = Wind pressure, in pascals (pounds per foot^2) (from Table 4-15)

d_1 = Outside diameter of conductor with ice, in centimeters (inches) (determine ice thickness from Table 4-15)

The total bus conductor loading can be determined using Equation 4-14:

Equation 4-14

$$F_T = \left[F_W^2 + \left(W_C + W_I \right)^2 \right]^{1/2} + k$$

Where:

F_T = Total bus conductor loading, in newtons per meter (pounds per foot)

F_W = Wind loading, in newtons per meter (pounds per foot)

W_C = Conductor weight, in newtons per meter (pounds per foot)

W_I =   Ice loading, in newtons per meter (pounds per foot)

k   =   *NESC* constant (from Table 4-15)

4.12.2.5 Conductor Sag: Calculate or obtain the maximum conductor sag. Methods for this calculation can be found in conductor manufacturers' literature. In some cases the maximum sag may occur during the most severe loading condition. For substation strain buses, the design tension is usually limited to 13,350 newtons (3000 pounds) per conductor under the most severe loading to minimize the size of support structures. These conductor tensions have to be coordinated with the support structure designs to ensure compatibility under all loading conditions. The tensions that will occur under unloaded conditions will be considerably less than the maximum.

For light loading conditions where ice loads are not considered, the maximum conductor sag may occur at the highest conductor temperature when the conductor length is at a maximum. For other loading conditions, sags should be determined for both high conductor temperatures and maximum loading so that adequate clearance from other equipment can be provided.

4.12.2.6 Suspension Insulator Effect: Calculate the suspension insulator effect on conductor sag. For short dead-ended spans, such as substation strain buses, the suspension insulators can have an appreciable effect on span sags. The following procedure can be used to calculate the insulator effect, which is added to the conductor sag for the total bus sag. See Figure 4-26.

$$C_I = \frac{T_C}{W_{IN}}$$

$$C_C = \frac{T_C}{W_C}$$

$$X_{BC} = \frac{C_I}{C_C} X_{BD} \qquad \left(Assume \ X_{BD} = \frac{L}{2} - \ell_{AB} \right)$$

$$Y_{BC} = C_I \left[\left(\cosh \frac{X_{BC}}{C_I} \right) - 1 \right]$$

$$\ell_{AC} = \ell_{AB} + C_I \sinh \left(\frac{X_{BC}}{C_I} \right)$$

$$X_{AC} = C_I \sinh^{-1} \left(\frac{\ell_{AC}}{C_I} \right)$$

$$Y_{AC} = C_I \left[\cosh \left(\frac{X_{AC}}{C_I} \right) - 1 \right]$$

$$Y_I = Y_{AC} - Y_{BC}$$

$$Y = Y_I + Y_C$$

Where:

C_I	=	Insulator catenary constant, in meters (feet)
C_C	=	Conductor catenary constant, in meters (feet)
X_{AC}	=	Horizontal distance from insulator support point to center of insulator catenary, in meters (feet)
X_{BC}	=	Horizontal distance from connection point of insulator string and conductor to center of insulator catenary, in meters (feet)
X_{BD}	=	Horizontal distance from connection point of insulator string and conductor to center of conductor catenary, in meters (feet)
P_{AB}	=	Length of insulator string, in meters (feet)
P_{AC}	=	Arc length from insulator support point to center of insulator catenary, in meters (feet)
Y	=	Total bus sag
Y_{AC}	=	Sag from insulator support point to center of insulator catenary, in meters (feet)
Y_{BC}	=	Sag from connection point of insulator string and conductor to center of insulator catenary, in meters (feet)
Y_I	=	Insulator sag, in meters (feet)
Y_C	=	Conductor sag, in meters (feet)
y	=	Total bus sag, including insulators and conductor, in meters (feet)
T_C	=	Horizontal conductor tension, in newtons (pounds)
W_{IN}	=	Insulator string weight, in newtons per meter (pounds per foot)
W_C	=	Conductor weight, in newtons per meter (pounds per foot)
L	=	Span length, in meters (feet)
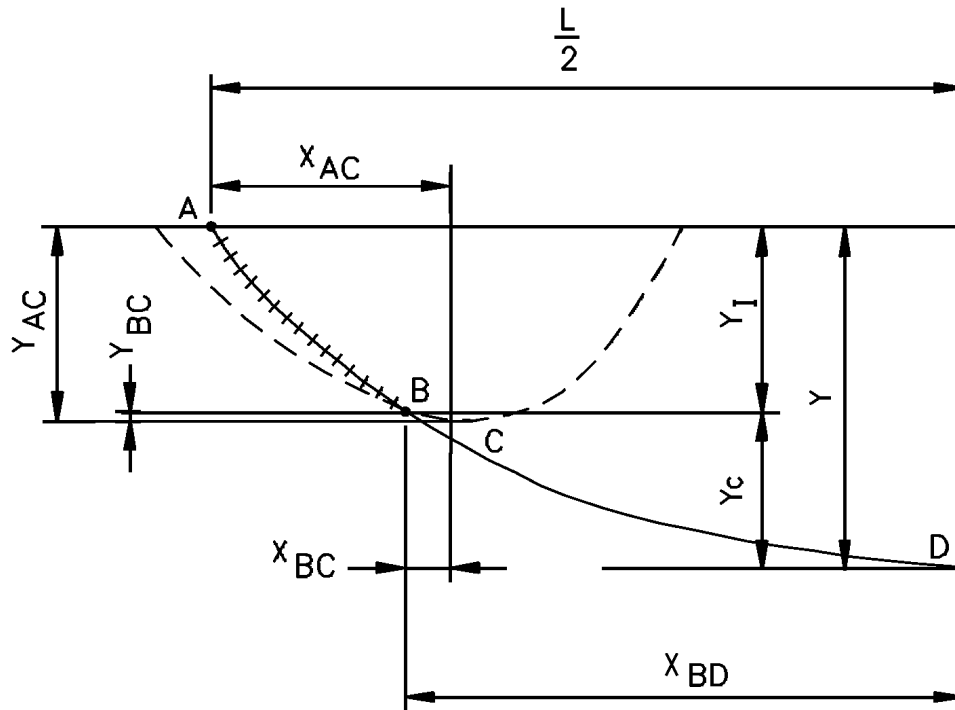
Figure 4-26: Short Strain Bus Insulator Effect

4.12.2.7 Stringing Tensions and Corresponding Sags: Calculate and chart stringing tensions and corresponding sags for a range of conductor temperatures expected during installation. Base the calculations on the assumed maximum tension that occurs under the most severe conductor loading. Include in the chart and list on the installation drawings span length, tension, and total bus sag for various conductor temperatures. Methods to determine the sags and tensions can be found in conductor manufacturers' literature.

After the conductor sags are calculated, add the suspension insulator sag to the conductor sags to determine the total bus sags as described in Section 4.12.

4.12.2.8 Sample Calculation of Bus Conductor Loading: Calculate the total bus conductor loading for the following strain bus:

Span length:	60.96 meters (200 feet)
Voltage:	161 kV
BIL:	750 kV
Conductor size:	795 kcmil 26/7 ACSR
Conductor diameter:	2.81 cm (1.108 in.)
Conductor weight:	16.0 N/m (1.094 lb/ft)
NESC loading:	heavy

Ice loading: Select ice thickness from Table 4-15:

$$W_I = 0.704(d_1^2 - d_2^2) \qquad\qquad (W_I = 0.311(d_1^2 - d_2^2))$$

$$W_I = (0.704)[(5.31)^2 - (2.81)^2] \qquad (W_I = 0.311)[(2.108)^2 - (1.108)^2]$$

$$W_I = 14.6 \text{ N/m} \qquad\qquad (W_I = 1.0 \text{ lb/ft})$$

Wind loading: Select wind pressure from Table 4-15:

$$F_W = 0.01 P_W d_1 \qquad\qquad (F_W = 0.083 P_W d_1)$$

$$F_W = (0.01)(190.0)(5.31) \qquad (F_W = (0.083)(4)(2.108))$$

$$F_W = 10.2 \text{ N/m} \qquad\qquad (F_W = 0.70 \text{ lb/ft})$$

Total bus conductor loading:

$$F_T = \left[F_W^2 + (W_C + W_I)^2\right]^{\frac{1}{2}} + k \qquad \left(F_T = \left[F_W^2 + (W_C + W_I)^2\right]^{\frac{1}{2}} + k\right)$$

$$F_T = \left[(10.2)^2 + (16.0 + 14.6)^2\right]^{\frac{1}{2}} + 4.38 \qquad \left(F_T = \left[(0.70)^2 + (1.094 + 1.0)^2\right]^{\frac{1}{2}} + 0.30\right)$$

$$F_T = 36.6\,\text{N/m} \qquad\qquad (F_T = 2.51\,\text{lb/ft})$$

4.12.2.9 Sample Calculation of Suspension Insulator Effect on Bus Sag: Calculate the suspension insulator effect on bus sag for the following strain bus:

Span length:	60.96 meters (200 feet)
Voltage:	161 kV
BIL:	750 kV
Conductor size:	795 kcmil 26/7 ACSR
Conductor diameter:	2.81 cm (1.108 in.)
Conductor weight:	16.0 N/m (1.094 lb/ft)
Conductor tension:	8896 N (2000 lb)
Number of suspension insulators (from Table 4-6):	10
Length of each insulator:	14.6 cm (5.75 in.)
Weight of each insulator:	48.9 N (11.0 lb)

$$C_I = \frac{T_C}{W_{IN}} \qquad\qquad \left(C_I = \frac{T_C}{W_{IN}}\right)$$

$$C_I = \frac{\left(\dfrac{8896}{48.9}\right)}{14.6\left(\dfrac{1}{100}\right)} \qquad\qquad \left(C_I = \frac{\left(\dfrac{2000}{11}\right)}{5.75\left(\dfrac{1}{12}\right)}\right)$$

$$C_I = 26.6\,\text{m} \qquad\qquad (C_I = 87.1\,\text{ft})$$

$$C_C = \frac{T_C}{W_C} \qquad\qquad \left(C_C = \frac{T_C}{W_{IN}}\right)$$

$$C_C = \frac{8896}{16} \qquad\qquad \left(C_C = \frac{2000}{1.094}\right)$$

$$C_C = 556 \text{ m} \qquad\qquad \left(C_C = 1828 \text{ ft}\right)$$

$$x_{BC} = \frac{C_I}{C_C} x_{BD} \qquad\qquad \left(x_{BC} = \frac{C_I}{C_C} x_{BD}\right)$$

$$x_{BC} = \frac{26.6}{555}\left(\frac{60.96}{2} - \frac{(10)(14.6)}{100}\right) \qquad\qquad \left(x_{BC} = \frac{87.1}{1828}\left(\frac{200}{2} - \frac{(10)(5.75)}{12}\right)\right)$$

$$x_{BC} = 1.39 \text{ m} \qquad\qquad \left(x_{BC} = 4.54 \text{ ft}\right)$$

$$y_{BC} = C_I\left[\left(\cosh\frac{x_{BC}}{C_I}\right) - 1\right] \qquad\qquad \left(y_{BC} = C_I\left[\left(\cosh\frac{x_{BC}}{C_I}\right) - 1\right]\right)$$

$$y_{BC} = (26.6)\left[\left(\cosh\frac{1.39}{26.6}\right) - 1\right] \qquad\qquad \left(y_{BC} = (87.1)\left[\left(\cosh\frac{4.54}{87.1}\right) - 1\right]\right)$$

$$y_{BC} = 0.0363 \text{ m} \qquad\qquad \left(y_{BC} = 0.118 \text{ ft}\right)$$

$$\ell_{AC} = \ell_{AB} + C_I \sinh\left(\frac{x_{BC}}{C_I}\right) \qquad\qquad \left(\ell_{AC} = \ell_{AB} + C_I \sinh\left(\frac{x_{BC}}{C_I}\right)\right)$$

$$\ell_{AC} = (10)\left(\frac{14.6}{100}\right) + (26.6)\sinh\left(\frac{1.39}{26.6}\right) \qquad\qquad \left(\ell_{AC} = (10)\left(\frac{5.75}{12}\right) + (87.1)\sinh\left(\frac{4.54}{87.1}\right)\right)$$

$$\ell_{AC} = 2.85 \text{ m} \qquad\qquad \left(\ell_{AC} = 9.33 \text{ ft}\right)$$

$$x_{AC} = C_I \sinh^{-1}\left(\frac{\ell_{AC}}{C_I}\right) \qquad \left(x_{AC} = C_I \sinh^{-1}\left(\frac{\ell_{AC}}{C_I}\right)\right)$$

$$x_{AC} = (26.6)\sinh^{-1}\left(\frac{2.85}{26.6}\right) \qquad \left(x_{AC} = (87.1)\sinh^{-1}\left(\frac{9.33}{87.1}\right)\right)$$

$$x_{AC} = 2.84\,\text{m} \qquad \left(x_{AC} = 9.31\,\text{ft}\right)$$

$$y_{AC} = C_I\left[\cosh\left(\frac{x_{AC}}{C_I}\right) - 1\right] \qquad \left(y_{AC} = C_I\left[\cosh\left(\frac{x_{AC}}{C_I}\right) - 1\right]\right)$$

$$y_{AC} = (26.6)\left[\cosh\left(\frac{2.84}{26.6}\right) - 1\right] \qquad \left(y_{AC} = (87.1)\left[\cosh\left(\frac{9.31}{87.1}\right) - 1\right]\right)$$

$$y_{AC} = 0.152\,\text{m} \qquad \left(y_{AC} = 0.498\,\text{ft}\right)$$

$$y_I = y_{AC} - y_{BC} \qquad \left(y_I = y_{AC} - y_{BC}\right)$$

$$y_I = 0.152 - 0.0363 \qquad \left(y_I = 0.498 - 0.118\right)$$

$$Y_I = 0.116\,\text{m} \qquad \left(Y_I = 0.38\,\text{ft}\right)$$

The value calculated for Y_I is then added to the conductor sag to determine the total bus sag. Use $2x_{BD}$ as the span length to calculate the conductor sag.

4.13 APPLICATION OF MOBILE TRANSFORMERS AND SUBSTATIONS

Mobile transformers or mobile substations can be used to provide temporary service during equipment maintenance, construction, emergency, or high load periods. Sufficient mobile units strategically placed can reduce or eliminate the requirements for on-site spare transformers.

Several aspects should be considered in applying mobile transformers or substations:

1. Size and maneuverability of the equipment
2. Installation location and provisions
3. Electrical clearances
4. Primary and secondary connections
5. Grounding

      6.   Auxiliary system requirements

      7.   Safety

4.13.1 Size and Maneuverability of the Equipment

One of the primary advantages of mobile equipment is its ability to be used at more than one location. To accommodate installation, adequate space has to be available to position and connect the equipment at all intended locations. It may be impossible to use larger units in some locations without substantial modifications because of the lack of sufficient space.

Substation entrances and access roads should be evaluated before committing particular equipment to the location in question. Prior planning can save much time and facilitate installation.

4.13.2 Installation Location and Provisions

The mobile transformer or substation location should permit primary and secondary connections as short as possible to the permanent substation equipment. It is desirable to utilize bare conductors for the connections. Sometimes, insulated cables can be used where electrical clearances cannot be maintained or where connections are long. The location should permit any required connections to be made quickly and safely without disturbing adjacent equipment. The ease and speed of installation can be influenced by the proximity of energized equipment.

Substations for which mobile equipment has been designated should have provisions for installation of the equipment. The provisions can simply be terminals on permanent substation equipment or buses for connecting the mobile equipment. It may be desirable to include bus extensions and/or disconnect switches in some substations to facilitate the connections, particularly if they may be made while the substation is energized.

If low-voltage ac or dc supplies are required, permanent facilities can be provided in the vicinity of where the mobile equipment will be positioned. A weatherproof cabinet containing any necessary terminal blocks, switches, or protective devices can be provided for terminating the low-voltage circuits. Temporary connections can be made from this cabinet to the control cabinet on the mobile equipment. Connections into the substation alarm system can also be provided in this or another cabinet. Terminal blocks, test switches, indicating lamps, or any other necessary equipment can be located in the cabinet.

Provisions for grounding the equipment can consist of terminals or ground rods connected to the main grounding grid.

4.13.3 Electrical Clearances

Maintaining adequate electrical clearances between the mobile equipment, its connections, and other equipment is of prime importance. Installation using bare conductors should not be considered for a location unless the minimum clearances listed in Tables 4-7 and 4-8 can be maintained. Insulated conductors can be used in some locations if the minimum clearances cannot be maintained.

4.13.4 Primary and Secondary Connections

All primary and secondary connections should be as short as possible and should be made with bolted connections. If possible, use bare conductors. However, for situations where minimum electrical clearances cannot be maintained or where connections are long, insulated conductors can be employed.

Conductors used should be sized to carry the maximum loads expected without overheating and to sustain anticipated fault currents without damage. They should be checked for sufficient length before connecting either end.

Temporary poles or structures may be required in some locations to facilitate the connections and maintain clearances. It is desirable to store any necessary equipment not part of the mobile unit at the substations, where required.

4.13.5 Grounding

Adequate grounding of mobile transformers and substations is extremely important for safe operation. At least two independent connections should be made between the trailer and the ground system. The mobile equipment should be connected to the substation ground grid whenever it is close to the substation. In situations where the mobile is located a long distance from the substation and connection to the substation ground grid is impractical, a separate ground system has to be provided.

4.13.6 Auxiliary System Requirements

Mobile unit transformers are usually designed for forced-cooled operation. Some units can provide the low voltage necessary for auxiliary equipment operation through the use of on-board supply transformers and equipment. For units without these provisions, low-voltage supplies can be obtained from the substation station service system.

Before the substation station service system is used to supply mobile unit auxiliary systems, the voltage(s) required by the auxiliary systems has to be checked against those available at the substation for compatibility. The system should also be checked for adequate capacity.

If an external dc supply is necessary for power or control applications, the substation control battery can be used. The system should be checked for proper voltage and adequate capacity prior to utilization.

4.13.7 Safety

Unless the mobile equipment is completely contained within another fenced area, a separate fence should be provided to surround the equipment. The fence has to provide the same security and protection as would a permanent substation fence. Gates should be provided with adequate locking facilities.

Mobile equipment usually requires some assembly during installation. Barriers and supports may require installation. Some supporting members or braces used to protect the equipment during transit may have to be removed. Assembly and installation should be in strict accordance with the manufacturer's instructions.

The equipment should be positioned on a level site and blocked to prevent movement. Ground slope at the installation location should not exceed the manufacturer's recommendations.

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4.15 LEGEND FOR EQUATIONS

C_C	Conductor catenary constant
C_D	Drag coefficient for structural shapes
C_I	Insulator catenary constant
D	Centerline-to-centerline spacing of bus conductors
d_1	Outside diameter of bus conductor with ice
d_2	Outside diameter of bus conductor without ice
E	Modulus of elasticity
W_C	Bus conductor weight per unit length
W_I	Ice loading on bus conductor per unit length
W_{IN}	Insulator string weight per unit length
F_{SC}	Short-circuit force on bus conductor per unit length
F_B	Maximum desirable bus conductor fiber stress
F_T	Total bus conductor loading per unit length
F_W	Wind loading on bus conductor per unit length
I	Moment of inertia
i	Short-circuit current
k	NESC conductor loading constant
K_{SC}	Short-circuit force reduction factor
K_{DE}	Multiplying factor for maximum vertical conductor deflection (inches)

K_{DM}	Multiplying factor for maximum vertical conductor deflection (centimeters)
K_{SE}	Multiplying factor for maximum bus support spacing (inches)
K_{SM}	Multiplying factor for maximum bus support spacing (centimeters)
L	Bus span length
L_M	Maximum bus support spacing
L_S	Conductor length for calculating insulator cantilever strength
ΔP	Conductor expansion (final length minus initial length)
P	Initial conductor length
P_{AB}	Length of insulator string
P_{AC}	Arc length from insulator support point to center of insulator catenary
P_W	Wind pressure on projected area of bus conductor
S	Bus conductor section modulus
ΔT	Bus conductor temperature variation (final temperature minus initial temperature)
T_C	Horizontal bus conductor tension
W_S	Minimum insulator cantilever strength
X_{AC}	Horizontal distance from insulator support point to center of insulator catenary
X_{BC}	Horizontal distance from connection point of insulator string and conductor to center of insulator catenary
X_{BD}	Horizontal distance from connection point of insulator string and conductor to center of conductor catenary
y	Total bus sag or deflection
Y_{AC}	Sag from insulator support point to center of insulator catenary
Y_{BC}	Sag from connection point of insulator string and conductor to center of insulator catenary
Y_I	Insulator sag
Y_C	Conductor sag
Y_{max}	Maximum permissible conductor deflection
α	Coefficient of linear thermal expansion

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CHAPTER 5
MAJOR EQUIPMENT

5.1 GENERAL

Major electrical equipment in a substation is generally categorized by longer delivery time, manufacture only after receipt of a purchase order, custom design to some degree, and much greater cost per unit than minor items such as insulators, bare wire, and conduit.

The specifications for such are determined not only by its relationship to other equipment in the substation but also by pre-established system conditions and performance requirements. The following sections in this chapter deal with the many possible variations in equipment. Procurement of major pieces of equipment usually depends on a detailed technical specification often developed after consultation with vendors.

Selection of the major equipment requires the utmost consideration. Cost, schedule, and performance penalties may be incurred as a result of improper selection. The design process has great flexibility for change in minor items, but very little can be done in the detailed substation design to overcome deficiencies in major equipment selection.

5.2 POWER TRANSFORMERS

5.2.1 General

The primary function of a power transformer is to transform system voltage from one nominal level to another. The transformer has to be capable of carrying (within the guidelines of ANSI/IEEE Std. C57.92) the power flow for its particular location in the system under various operating conditions and contingencies, such as line or transformer outages.

This section deals primarily with oil-filled power transformers with nominal primary voltage ratings of 230 kV and below and utilizing one of the following methods of cooling:

1. Self-cooled (OA)
2. Self-cooled and assisted by forced-air (OA/FA for one stage; OA/FA/FA for two stages)
3. Self-cooled and assisted by forced-air and forced-oil (OA/FA/FOA or OA/FOA/FOA for two stages)

Other methods of cooling such as with water are available and are described in IEEE Std. C57.12.00. The type of cooling used is based on the requirements of the specifications, the size of the transformer, and the manufacturer's standard design.

Meeting these specific requirements usually results in the power transformer's being the largest, heaviest, and most costly piece of equipment used in a substation.

Because of their great importance and complexity, power transformers require special care in their application, specification, and procurement. This is best accomplished by taking full advantage of applicable industry standards and guides of national organizations such as the American National Standards Institute (ANSI), Institute of Electrical and Electronic Engineers (IEEE), National Electrical

Manufacturers Association (NEMA), etc., and RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

The following discussion highlights various aspects of power transformers and provides guidance and recommendations to assist cooperatives in obtaining the proper equipment for their systems. Most of this discussion will apply to step-down transformers, especially those not included in the List of Materials. Refer to RUS Bulletin 50-91, "RUS Specification for Step-Down Distribution Substation Transformers," for step-down transformers.

5.2.2   Types

Power transformers may be either autotransformers or multiwinding conventional transformers. A three-phase installation may consist of a three-phase unit or three single-phase units. The decision as to what type of transformer to purchase depends on such factors as initial installed cost, maintenance costs, operating cost (efficiency), reliability, etc. Three-phase units have lower construction and maintenance costs and can be built to the same efficiency ratings as single-phase units. The initial cost of a three-phase transformer is usually approximately one-third less than four single-phase units. Additionally, the exposure of three-phase units to long outages can be minimized system-wide when a mobile substation or transformer is available for backup in case of failure. RUS Bulletin 61-16, "Guide for Economic Evaluation of Distribution Transformers," provides information for evaluating substation transformer costs.

The kVA ratings for various sizes of transformers are covered by the standards. IEEE Std. C57.12.00, Table 1, defines the preferred continuous ratings for both single- and three-phase units. ANSI Std. C57.12.10, Tables 2 and 12, further define the ratings of transformers with and without cooling. Transformers 10,000 kVA and below can accommodate one stage of cooling only, while transformers larger than 10,000 kVA can include up to two stages of cooling. Each stage of cooling increases the capacity of the transformer by a fixed percentage of the base (OA) rating. For three-phase transformers rated between 750 and 2000 kVA, increasing the base level of cooling to forced air cooling will increase the continuous kVA capacity by 15 percent. For transformers rated 2500 kVA to 10,000 kVA, the increase is 25 percent. For transformers above 10,000 kVA, additional stages of cooling may be used to increase the continuous kVA rating of the transformer by 33 percent per stage. Transformers larger than those listed in these tables can be purchased and would normally be triple rated or would have provision for the future addition of two stages of cooling equipment to produce a triple rating.

The choice between conventional two- or three-winding transformers and autotransformers involves their basic differences as they may affect the application and cost factors. In general, autotransformers are considered primarily because of cost advantages where the voltage transformation ratio is favorable, up to possibly 3/1. Beyond this ratio, the cost advantage of autotransformers diminishes. Also, autotransformers are wye connected and thus provide only an in-phase angular relationship between primary and secondary voltages.

Other advantages of autotransformers are smaller physical size, lighter weight, lower regulation (voltage drop in transformer), smaller exciting currents (easier no-load switching), and lower losses. The main disadvantages of autotransformers are lower reactance (impedance), more complex design problems, and adverse affect on ground relaying. These problems can usually be resolved.

5.2.3   Ratings

5.2.3.1   Capacity: The selection of substation transformer kVA capacity should be based on an acceptable up-to-date engineering study. The selection should consider the effects of load cycle, load factor, and ambient temperature as described in ANSI/IEEE Std. C57.92, "Guide for Loading Mineral Oil-Immersed Power Transformers up to and Including 100 MVA With 55°C or 65°C Average Winding Rise."

Since cooling efficiency decreases with increase in altitude, the transformer manufacturer should be informed when the transformer will be operated at an elevation above 1000 meters (3300 feet) so that the proper cooling system can be provided. See Tables 5-1 and 5-2 for guidance on the effect of altitude on temperature rise. Also, multiwinding transformers with loads on various windings at different power factors have higher load losses and may require additional cooling capacity.

Table 5-1: Maximum Allowable Average Temperature* of Cooling Air for Carrying Rated kVA.
Ref. ANSI/IEEE Std. C57.92-1981, Table A1. Copyright © 1981. IEEE. All rights reserved.

Method of Cooling Apparatus	1000 Meters (3300 Feet)	2000 Meters (6600 Feet)	3000 Meters (9900 Feet)	4000 Meters (13 200 Feet)
	Degrees Celsius			
Liquid-Immersed Self-Cooled	30	28	25	23
Liquid-Immersed Forced-Air-Cooled	30	26	23	20
Liquid-Immersed Forced-Oil-Cooled with Oil-to-Air Cooler	30	26	23	20

*   It is recommended that the average temperature of the cooling air be calculated by averaging 24 consecutive hourly readings. When the outdoor air is the cooling medium, the average of the maximum and minimum daily temperatures may be used. The value obtained in this manner is usually slightly higher, by not more than 0.3°C, than the true daily average.

Table 5-2: Rated kVA Correction Factors for Altitudes Greater than 3300 ft (1000 m).
Ref. ANSI/IEEE Std. C57.92-1981, Appendix. Copyright © 1981. IEEE. All rights reserved.

Types of Cooling	Derating Factor (%)
Liquid-immersed air-cooled	0.4
Liquid-immersed water-cooled	0.0
Liquid-immersed forced-air-cooled	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-air cooler	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-water cooler	0.0

In addition to selecting a transformer capable of satisfying the basic capacity requirements, it is also desirable to give due consideration to inventory and standardization with the objective of simplifying spare parts, testing, maintenance, and unit sparing problems.

5.2.3.2   Temperatures: Normal transformer design is based on ambient temperatures of 40°C maximum, 30°C average over 24 hours, and –20°C minimum. Abnormal ambient temperatures should

be made known to the manufacturer at the time of purchase since they usually require modifications in the design of the transformer.

5.2.3.3 **Voltage:** Nominal voltage ratings of a transformer are selected to conform to system voltage conditions. Tables 5-3, 5-4, 5-5, and 5-6 list standard voltages through 230 kV. According to ANSI/ IEEE Std. C57.12.10, transformers should not be subjected to operating voltages or volts per hertz above 105 percent of any rated secondary tap when operating loaded to nameplate kVA rating when the load power factor is 80 percent or higher and the frequency is at least 95 percent of rated value. In addition, transformers should not be operated continuously above 110 percent of rated secondary tap when operating at no-load. Multiwinding transformers and autotransformers may be restricted further depending on the specific design criteria specified when the transformer was purchased. Refer to the original specifications or the manufacturer for guidance. Also refer to ANSI Std. C84.1 for further guidance on maximum permissible operating voltages.

Table 5-3: Range of Voltage and Kilovolt-Ampere Ratings for Single-Phase Transformers, 833-8333 kVA. Ref. ANSI/IEEE Std. C57.12.10-1988, Table 3. Reproduced with permission of the National Electrical Manufacturers Association.

High-Voltage Ratings (V)	Low-Voltage Ratings (V)				
	480	2400/4160Y, 2520/4360Y, 4800/8320Y, - 5040/8720Y	6900/11 950Y, 8355/23 085PW, 7560/13 090Y, 7620/13 200Y, - 7970/13 800Y	23 555W, 12 600, 13 200, 13 800 14 400	14 400/24 940Y, - 34 500, 19 920/34 500Y, - 20 920/36 230
	Self-Cooled (OA) Kilovolt-Ampere Ratings (kVA)				
2400/4160Y	833	-	-	-	-
4800/8320Y	833	-	-	-	-
6900/11 950Y,	833, 1250	833-2500	-	-	-
6930/12 000Y,	-	-	-	-	-
7200/12 470Y,	-	-	-	-	-
7620/13 200Y,	-	-	-	-	-
7970/13 800Y,	-	-	-	-	-
12 000, 13 200,	-	-	-	-	-
13 800	-	-	-	-	-
23 000	833, 1250	833-2500	833-2500	-	-
34 500	833, 1250	833-2500	833-3333	833-3333	-
46 000	833, 1250	833-2500	833-8333	833-3333	-
69 000	-	833-2500	833-8333	833-3333	-
115 000	-	2500	2500-8333	2500-8333	2500-8333
138 000	-	2500	2500-8333	2500-8333	2500-8333

Notes:
(1) All voltages are Δ unless otherwise indicated.
(2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included.
     Kilovolt-ampere ratings separated by a comma indicate that only those listed are included.
(3) Bold-type voltages listed in ANSI Std. C84.1-1982.
(4) Italics-type voltages not listed in ANSI Std. C84.1-1982.

Table 5-4: Range of Voltage and Kilovolt-Ampere Ratings for Three-Phase Transformers Without Load Tap Changing, 750-10 000kVA. Ref ANSI/IEEE Std. C57.12.10-1988, Table 4. Reproduced with permission of the National Electrical Manufacturers Association.

High-Voltage Ratings (V)	Low-Voltage Ratings (V)					
	480Y/277 **480**	**2400**,*2520* **4160Y/2400**, *4360Y/2520*	**4800**,*5040*, **8320Y/4800**, *8720Y/5040*	**6900,7200**,*7560,* **12 407Y/7200**, *13 090Y/7560,* **13 200Y/7620** **13 800Y/7970**,	**13 800**, **12 000**, *12 600,* **13 200**, *14 400*	24 940Grd/14 000 **34 500**, **34 500GrdY/19 920**, *36 230GrdY/20 920*
	Self-Cooled (OA) Kilovolt-Ampere Ratings (kVA)					
2400	750-1500	-	-	-	-	-
4160,4800	750-1500	-	-	-	-	-
6900,7200	750-2500	1000-3750	-	-	-	-
12 000	750-2500	1000-7500	-	-	-	-
12 470	-	-	-	-	-	-
13 200	-	-	-	-	-	-
13 800	-	-	-	-	-	-
23 000	-	1000-7500	1000-10 000	1000-10 000	-	-
34 500	-	1000-7500	1000-10 000	1000-10 000	1000-10 000	-
46 000	-	1500-7500	1500-10 000	1500-10 000	1500-10 000	-
69 000	-	1500-7500	1500-10 000	1500-10 000	1500-10 000	-
115 000	-	5000-7500	5000-10 000	5000-10 000	5000-10 000	5000-10 000
138 000	-	5000-7500	5000-10 000	5000-10 000	5000-10 000	5000-10 000

Notes:
  (1) All voltages are Δ unless otherwise indicated.
  (2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included.
  (3) Bold-type voltages listed in ANSI Std. C84.1-1982.
  (4) Italics-type voltages not listed in ANSI Std. C84.1-1982.

Table 5-5: Range of Voltage and Kilovolt-Ampere Ratings for Three-Phase Transformers
with Load Tap Changing, 3750-10 000 kVA. Ref. ANSI/IEEE Std. C57.12.10-1988, Table 5.
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High-Voltage Ratings (V)	Low-Voltage Ratings (V)					
	2400,_2520,_ **4160Y/2400,** _4360Y/2520_	**4800,**_5040,_ **8320Y/4800,** _8720Y/5040_	**6900,7200,**_7560,_ **12 470Y/7200,** _13 090Y/7560,_ **13 200Y/7620, 13 800Y/7970**	**13 800 12 000,**_12 600_ **13 200,**_14 400_	**24940Grd/ 14000**	**24 940Grd/14 000** **34 500,** **34 500GrdY/19 920,** _36 230GrdY/20 920_
	Self-Cooled (OA) Kilovolt-Ampere Ratings (kVA)					
6900,7200	3750	-	-	-	-	-
12 000	3750-7500	-	-	-	-	-
12 470	-	-	-	-	-	-
13 200	-	-	-	-	-	-
13 800	-	-	-	-	-	-
23 000	3750-7500	3750-10 000	3750-10 000	-	-	-
34 500	3750-7500	3750-10 000	3750-10 000	3750-10 000	-	-
46 000	3750-7500	3750-10 000	3750-10 000	3750-10 000	-	-
69 000	3750-7500	3750-10 000	3750-10 000	3750-10 000	-	-
115 000	5000-7500	5000-10 000	5000-10 000	5000-10 000	5000-10 000	5000-10 000
138 000	5000-7500	5000-10 000	5000-10 000	5000-10 000	5000-10 000	5000-10 000

Notes:
(1) All voltages are Δ unless otherwise indicated.
(2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included.
(3) Bold-type voltages listed in ANSI Std. C84.1-1982.
(4) Italics-type voltages not listed in ANSI Std. C84.1-1982.

Table 5-6: Range of Voltage and Kilovolt-Ampere Ratings for Three-Phase Transformers
With or Without Load Tap Changing, 12 000-60 000 kVA. Ref. ANSI/IEEE Std. C57.12.10-1988,
Table 6. Reproduced with permission of the National Electrical Manufacturers Association.

High Voltage Ratings (V)	Low-Voltage Ratings (V)				
	4800,*5040,* **8320Y/4800,** *8720Y/5040*	**6900,7200,***7560,* **12 407Y/7200,** *13 090Y/7560,* *13 200Y/7620,* **13 800Y/7970**	**12 000**,*12 600,* **13 200, 13 800,** *14 400*	**24 940GrdY/14 400**	**34 500,** **34 500GrdY/19 920,** *36 230GrdY/20 920*
	Self-Cooled (OA) Kilovolt-Ampere Ratings (kVA)				
23 000	12 000-15 000	12 000-30 000	-	-	-
34 500	12 000-15 000	12 000-30 000	12 000-30 000	-	-
46 000	12 000-15 000	12 000-30 000	12 000-30 000	-	-
69 000	12 000-15 000	12 000-30 000	12 000-30 000	-	-
115 000	12 000-15 000	12 000-60 000	12 000-60 000	12 000-60 000	12 000-60 000
138 000	12 000-15 000	12 000-60 000	12 000-60 000	12 000-60 000	12 000-60 000
161 000	12 000-15 000	12 000-60 000	12 000-60 000	12 000-60 000	12 000-60 000
230 000	12 000-15 000	12 000-60 000	12 000-60 000	12 000-60 000	12 000-60 000

Notes:
    (1) All voltages are Δ unless otherwise indicated.
    (2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included.
    (3) Bold-type voltages listed in ANSI Std. C84.1-1982.
    (4) Italics-type voltages not listed in ANSI Std. C84.1-1982.

5.2.3.4   **Basic Insulation Levels (BIL):** Tables 5-7, 5-8, and 5-9 list basic insulation levels commonly used for various system voltages. Neutral terminal BIL may be specified at a different level than the line terminals depending on the type of system grounding being used. Table 5-10 lists the minimum insulation levels for neutral terminals. Continuous improvements over the years in the protective margins provided by surge arresters have enabled users to select reduced insulation levels for transformers, at appreciable cost reductions, without sacrificing reliability.

Table 5-7: Relationships of Nominal System Voltage to Maximum System Voltage and Basic Lightning Impulse Insulation Levels (BIL) for Systems 765 kV and Below.
Ref. IEEE Std. C57.12.00-1993, Table 3. Copyright © 1993. IEEE. All rights reserved.

Application	Nominal System Voltage (kV rms)	Maximum System Voltage (from ANSI C84.1-1989 [2] and ANSI C92.2-1987 [4]) (kV rms)	Basic Lightning Impulse Insulation Levels (BIL) in Common Use (kV crest)			
Distribution	1.2		**30**			
	2.5		**45**			
	5.0		**60**			
	8.7		**75**			
	15.0		**95**			
	25.0		**150**	**125**		
	34.5		**200**	**150**	125	
	46.0	48.3	**250**	200		
	69.0	72.5	**350**	250		
Power	1.2		**45**	**30**		
	2.5		**60**	**45**		
	5.0		**75**	**60**		
	8.7		**95**	**75**		
	15.0		**110**	**95**		
	25.0		**150**			
	34.5		**200**			
	46.0	48.3	**250**	200		
	69.0	72.5	**350**	250		
	115.0	121.0	550	**450**	350	
	138.0	145.0	650	**550**	450	
	161.0	169.0	750	**650**	550	
	230.0	242.0	900	825	**750**	650
	345.0	362.0	1175	1050	900	
	500.0	550.0	1675	1550	1425	1300
	765.0	800.0	2050	1925	1800	

NOTES:
(1) BIL values in bold typeface are listed as standard in one or more of ANSI/IEEE Std. C57.12.10-1987 [B1], ANSI/IEEE Std. C57.12.20-1988 [B3], ANSI/IEEE Std. C57.12.21-1980 [B4], ANSI/IEEE Std. C57.12.22-1989 [B5], ANSI/IEEE Std. C57.12.23-1986 [B6], ANSI/IEEE Std. C57.12.24-1988 [B7], ANSI/IEEE Std. C57.12.25-1990 [B8], and ANSI/IEEE Std. C57.12.26-1992 [B13].
(2) Single-phase distribution and power transformers and regulating transformers for voltage ratings between terminals of 8.7 kV and below are designed for both Y and Ä connection, and are insulated for the test voltages corresponding to the Y connection so that a single line of transformers serves for the Y and Ä applications. The test voltages for such transformers, when operated and connected, are therefore higher than needed for their voltage rating.
(3) For series windings in transformers, such as regulating transformers, the test values to ground shall be determined by the BIL of the series windings rather than by the rated voltage between terminals.
(4) Values listed as nominal system voltage in some cases (particularly voltages 34.5 kV and below) are applicable to other lesser voltages of approximately the same value. For example, 15 kV encompasses nominal system voltages of 14 440 kV, 13 800 kV, 13 200 kV, 13 090 kV, 12 600 kV, 12 470 kV, 12 000 kV, 11 950 kV, etc.

Table 5-8: High-Voltage Winding Insulation Levels of Single-Phase Transformers.
Ref. ANSI/IEEE Std. C57.12.10-1988, Table 7.
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High-Voltage Ratings (V)	Basic Impulse Insulation Level (kV)
2400/4160Y	75
4800/8320Y	95
6900/11 950Y	110
7200/12 470Y	110
7620/13 200Y	110
12 000	110
13 200	110
13 800	110
23 000	150
34 500	200
46 000	250
69 000	350
115 000	450
138 000	550

Notes:
(1) All voltages are Δ unless otherwise indicated.
(2) Bold type are voltages listed in ANSI C84.1-1982.
(3) Italics type are voltages not listed in ANSI C84.1-1982.

Table 5-9: High-Voltage Winding Insulation Levels of Three-Phase Transformers.
Ref. ANSI/IEEE Std. C57.12.10-1988, Table 8.
Reproduced with permission of the National Electrical Manufacturers Association.

High-Voltage Ratings (V)	Basic Impulse Insulation Level (kV)	
	Distribution Transformers	Power Transformers
2 400	45	60
4 160	60	75
4 800	60	75
6 900	75	95
7 200	75	95
12 000	95	110
13 200	95	110
13 800	95	110
23 000	125	150
34 500	150	200
46 000	-	250
69 000	-	350
115 000	-	450
138 000	-	550
161 000	-	650
230 000	-	750

Notes:
(1) All voltages are Δ unless otherwise indicated.
(2) Distribution BILs only applicable to non-load-tap-changing transformers.

Table 5-10: Minimum Insulation Levels at Neutral.
Ref. ANSI/IEEE Std. C57.12.00-1993, Table 7. Copyright © 1993. IEEE. All rights reserved.

Application	Nominal System Voltage (kV)*	Minimum Low-Frequency Insulation Level (kV rms)	
		Grounded Solidly or Through a Current Transformer or Through a Regulating Transformer	Grounded Through a Ground-Fault Neutralizer, or Isolated but Impulse Protected
	Column 1	Column 2	Column3
Distribution	1.2	10	10
or	2.6	15	15
Power	5.0	19	19
	8.7	26	26
	15.0	26	26
	25.0	26	34
	34.5	26	50
	46.0	34	70
	69.0	34	95

*   For higher line terminal system voltages than shown above, the insulation level at the neutral
       shall be specified to conform with service requirements, but in no case shall be less than 34 kV.
NOTE: When specified, Y-Y connected transformers using a common, solidly grounded neutral may
       use a neutral bushing selected in accordance with the requirements of the LV winding.

Any selection of a transformer with reduced BIL is a user responsibility and requires knowledge of
certain system characteristics.

On effectively grounded systems, a reduced BIL of one step below full basic insulation level may be
appropriate for transformers with nominal ratings of 115 kV and above. An insulation coordination
study may be required to ensure that adequate margin is maintained between transformer insulation
strength and the protective level of protective equipment.

5.2.3.5   Loading: A transformer can supply a load beyond its nameplate rating for various periods
of time, which may or may not affect its normal life, depending on several factors related to
temperature conditions in the transformer. See ANSI/IEEE Std. C57.92 for additional guidance on
transformer loading.

5.2.4   Taps

No-load tap changers (NLTC) and/or load tap changers (LTC) can be obtained on power transformers.
The addition of no-load taps in the primary of a substation transformer makes it possible to adapt the
transformer to a range of supply voltages (usually a 10 percent overall range of which 5 percent is
above nominal and 5 percent below nominal, usually in 2.5 percent steps). Since no-load taps are not
capable of interrupting any current including transformer charging current, the transformers have to be
de-energized when the manual no-load tap position is changed. All taps should have full capacity
ratings. The individual tap voltages should be as specified in ANSI/IEEE Std. C57.12.10, paragraph
4.5.

Any decision to use load tap changing transformers should be based on a careful analysis of the
particular voltage requirements of the loads served and consideration of the advantages and

disadvantages, including costs, of alternatives such as separate voltage regulators. When load tap changing transformers are specified, they have to comply with the requirements of ANSI/IEEE Std. C57.12.00, and ANSI/IEEE Std. C57.12.10.

5.2.5   Impedance

Transformer impedance affects transformer voltage regulation, efficiency, and magnitude of through-short-circuit currents. Both regulation and efficiency are generally improved with lower impedance. However, these desirable results should be viewed along with higher through-fault currents permissible with lower impedance.

Higher load-side fault currents can be potentially damaging to the transformer and may also require higher fault current ratings of load-side equipment at increased cost. Prudent compromises are thus often required in specifying transformer impedance.

Where through-fault currents are not a significant factor, it is generally desirable to specify as low impedance as possible that will not result in increased transformer cost. Standard impedance ranges for various transformer BIL ratings are listed by manufacturers, and cost penalties may apply when the impedance falls above or below these ranges. The standards permit manufacturing tolerances of ±7.5 percent of the specified impedance for two-winding transformers and ±10.0 percent for multiwinding transformers and autotransformers. These are important to remember if transformer paralleling is being considered and if the margin between transformer through-fault current and equipment ratings is very close. Substation transformer impedance needs to comply with the requirements of ANSI/IEEE Std. C57.12.10, Section 6. Standard impedances for various voltage ratings are given in Table 5-11. Distribution substation transformers (500 kVA or smaller) should be specified with standard impedance where possible. These impedances are sufficient to make the transformer self protecting under any secondary faults.

5.2.6   Phase Relation

Proper phase relationships between the various winding voltages are extremely important in transformer application. These have to be selected to fit existing or planned conditions in the particular system.

Standard single-phase substation transformers are built with subtractive polarity. The polarity of a three-phase transformer is fixed by its connections between phases and by relative location of leads. A standard delta-wye or wye-delta, three-phase, step-down transformer will result in the high-side voltages leading their respective low-side voltages by 30 degrees. An installation of three single-phase transformers can be connected to accomplish this same relationship.

Autotransformers are connected wye-wye, and no phase angle exists between the high- and low-side voltages. This may preclude the use of autotransformers, in some cases, even when they are otherwise preferred. See Section 5.2.7 concerning the phase relationship required for parallel operation of transformers.

Also give attention to the proper physical orientation of transformers within the substation and to their connections to ensure that the proper phasing is obtained on all buses. Standard bushing arrangement on a three-phase transformer, when viewed from the low-voltage side, is from left to right H_0 (when required), H_1, H_2, and H_3 on the high-voltage side and X_0 (when required), X_1, X_2, and X_3 on the low-voltage side. If a tertiary or third winding is provided, the bushing arrangement is Y_1, Y_2, and Y_3 left to right when viewed from the side nearest these bushings.

Table 5-11: BILs and Percentage Impedance Voltages at Self-Cooled (OA) Rating.
Ref. ANSI/IEEE Std. C57.12.10-1988, Table 10 and Section 4.6.
Reproduced with permission of the National Electrical Manufacturers Association.

| High-Voltage BIL (kV) | Without Load Tap Changing | | With Load Tap Changing |
	Low Voltage 480 V	Low Voltage 2400 V and Above	Low Voltage 2400 V and Above
60-110	5.75*	5.5*	—
150	6.75	6.5	7.0
200	7.25	7.0	7.5
250	7.75	7.5	8.0
350	—	8.0	8.5
450	—	8.5	9.0
550	—	9.0	9.5
650	—	9.5	10.0
750	—	10.0	10.5

*   For transformers greater than 5000 kVA self-cooled, these values shall be the same as those
shown for 150 kV HV BIL.

1. Impedance Voltage:
    a. Percentage Impedance Voltage: the percentage impedance voltage at the self-cooled rating as
        measured on the rated voltage connection shall be as listed in Table 5.2-10.
    b. Tolerance on Impedance Voltage: the tolerance shall be as specified in ANSI/IEEE
        Std. C57.12.00-1993.
    c. Percentage Departure of Impedance Voltage on Taps for De-energized Operation: the
        percentage departure of tested impedance voltage on any tap from the tested impedance
        voltage at rated voltage shall not be greater than the total tap voltage range expressed as a
        percentage of the rated voltage.

Note: This does not apply to load-tap-changing taps.

Refer to ANSI/IEEE Std. C57.12.70 for transformer terminal markings and connections.

5.2.7   Parallel Operation of Transformers

In most cases, the purchase of two smaller size transformers, to be operated in parallel in one circuit, in
lieu of one full-size transformer, is not recommended. Two transformers will cost more than a single
transformer of equivalent capacity, their combined losses are higher, and they require a more elaborate
and expensive substation structure to accommodate them. However, where a situation exists for
possible parallel operation, such as where continuity of at least partial service in event of failure of one
unit is of great importance, the transformers should be individually protected and the following
guidelines considered.

Any two or more transformers can be operated in parallel, provided their impedances are in the same
order of magnitude when considered on their own kVA base, their voltage taps and voltage ratios are
essentially the same, and their polarity and phase voltage displacement are or can be made alike.

Equal impedances will permit proportionate sharing of the load between transformers. If not equal, the
load will be divided in inverse proportion to the magnitude of the impedance. This condition is

satisfactory within reasonable limits, as determined by requirements, and may be of little consequence where the larger of two transformers has the lower impedance and will carry more than its proportionate share of the load. However, if the smaller unit has the lower impedance, it will carry more than its share of the load and may even become severely overloaded, while the larger unit still has available capacity. This is demonstrated in the following example.

Protecting transformers operating in parallel as a single unit is not recommended. The sensitivity of the high-side protection is significantly reduced, and the occurrence of nuisance tripping during energization is increased due to incorrect differential relay harmonic restraint unit operation.

5.2.7.1   Condition I - Larger Transformer Has the Smaller Impedance: Two transformers, Tl and T2, are operating in parallel. Tl is rated 10 MVA with an impedance of 10 percent. T2 is rated 25 MVA with an impedance of 7 percent. On a common 100 MVA base, impedance of Tl is 100 percent and impedance of T2 is 28 percent.

Power flow divides inversely with the relative impedances on a common base. Assuming a total power flow of 30 MVA, Tl would carry 6.6 MVA and T2 would carry 23.4 MVA, both within their ratings.

The power flow distribution is obtained by solving two simultaneous equations, where Pl and P2 represent the power flows through Tl and T2, respectively, and Z_{100} is the impedance on a 100 MVA base:

Equation 5-1

Pl + P2 = 30 MVA

Equation 5-2

$$\frac{P1}{P2} = \frac{Z_{100} \ (of \ T2)}{Z_{100} \ (of \ T1)}$$

5.2.7.2   Condition II - Smaller Transformer Has the Smaller Impedance: The same as Condition I, except Tl has an impedance of 7 percent, and T2 an impedance of 10 percent. On a 100 MVA base, the impedance of Tl is 70 percent and the impedance of T2 is 40 percent.

Tl would carry 10.9 MVA and T2 would carry 10.1 MVA. Tl is clearly overloaded, whereas T2 has capacity to spare.

5.2.7.3   Condition III - Both Transformers Have Equal Impedances - Preferred Condition:
The same as Condition I, except both TI and T2 have equal impedances on their own base of 8 percent. On a 100 MVA base, Tl has an impedance of 80 percent, and T2 has an impedance of 32 percent. TI would carry 8.6 MVA and T2 would carry 21.4 MVA. Each transformer is carrying its correct share in proportion to its MVA rating.

From an impedance standpoint, it has generally been accepted that transformers can be paralleled successfully if the actual or nameplate impedance of one does not differ by more than 7 ½ percent from the actual or nameplate impedance of the other. For example, a transformer having an impedance of

6 percent can be paired with a transformer having an impedance anywhere between 5.55 percent (0.925 x 6 percent) and 6.45 percent (1.075 x 6 percent).

Equal tap voltages, or voltage ratios, will permit each of the paralleled transformers to operate as if it were isolated. But unequal tap voltages will create a circulating current flowing forward through the unit having the higher voltage and in a reverse or leading direction through the unit with the lower voltage. This condition is limited only by the series impedance of the two transformers in the current circulation circuit and by the difference in voltage causing the current flow. This condition can be very severe and has to be closely analyzed whenever such operation is contemplated. The condition is most severe when the transformers are not carrying load. It usually is modified sufficiently when load is being carried, and voltage regulation due to load so modifies the voltage difference as to reduce the circulating current to an insignificant level.

Where paralleled transformers are equipped with load tap changers and line drop compensators, incorporate paralleling control schemes into the LTC controls. Schemes that may be evaluated include:

1. Negative Reactance Method
2. Step-by-Step Method
3. Out-of-Step Switch Method
4. Cross-Current Compensation Method

5.2.8   Dielectric Requirements

A transformer in service may be exposed to a variety of dielectric stresses. Lightning impulses may reach the terminals of the transformer because of direct hits or, more likely, in the form of traveling waves coming in over connecting lines. Such traveling waves are produced when the connecting lines are exposed to lightning strokes.

Direct hits are practically impossible where adequate direct stroke protection is provided over the substation in the form of ground wires and/or masts. The magnitude of traveling wave impulses reaching the transformer depends on:

- The initial magnitude of the strokes
- The distance the wave has to travel
- Transmission line characteristics, such as surge impedance, insulation level, and type of ground wire protection
- Transformer characteristics and protective characteristics of surge protective devices provided

How well the transformer can withstand any impulse voltages reaching it depends on the condition of the insulation at the time of the impulse. Basic insulation levels can be verified by impulse tests. Most large transformers receive impulse tests prior to shipment from the factory. This may not be a routine test performed by the manufacturer for certain size transformers. If an impulse test is desired, include this requirement in the testing section of the transformer specifications.

Normal line energization and deenergization or power circuit breaker operations during system faults produce switching surges that travel down the conductors to the connected transformers. Switching surges generally present no particular problem to transformers rated 230 kV and below. Transformers rated 115 kV and above are designed for the switching impulse insulation levels (BSL) associated with their assigned BIL. Switching impulse insulation levels are defined in Tables 5-12 and 5-13. In

general, switching surge withstand capability of a transformer is approximately 83 percent of its BIL. Where justified, factory switching surge tests may be applied to verify switching surge withstand capability.

Table 5-12: Dielectric Insulation Levels for Distribution Transformers
and Class I Power Transformers.* Ref. IEEE Std. C57.12.00-1993, Table 4.
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| Application | Basic Lightning Impulse Insulation Level (BIL) (kV crest) | Chopped-Wave Impulse Levels | | Front-of-Wave Impulse Levels | | Low-Frequency Test Level (kV rms) |
		Minimum Voltage (kV crest)	Minimum Time to Flashover (μs)	Minimum Voltage (kV crest)	Specific Time to Sparkover (μs)	
	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Distribution	30	36	1.0	—	—	10
	45	54	1.5	—	—	15
	60	69	1.5	—	—	19
	75	88	1.6	—	—	26
	95	110	1.8	—	—	34
	125	145	2.25	—	—	40
	150	175	3.0	—	—	50
	200	230	3.0	—	—	70
	250	290	3.0	—	—	95
	350	400	3.0	—	—	140
Power	45	50	1.5	—	—	10
	60	66	1.5	—	—	15
	75	83	1.5	—	—	19
	95	105	1.8	165	0.5	26
	110	120	2.0	195	0.5	34
	150	165	3.0	260	0.5	50
	200	220	3.0	345	0.5	70
	250	275	3.0	435	0.5	95
	350	385	3.0	580	0.58	140

*   See Section 5.10 for a description of Class I power transformers.

NOTES:
  (1)   Front-of-wave impulse levels have to be specified prior to design of the transformer.
  (2)   Front-of-wave tests are not recommended on low-voltage or tertiary windings that will not be exposed to lightning and that are connected directly to user equipment and have low impulse strengths. This includes low-voltage windings of generator transformers and transformer windings that operate at 5000 V or less.
  (3)   Internal and external phase-to-phase low-frequency insulation test levels shall not be reduced below the levels listed in Table 6.
  (4)   The insulation levels for distribution transformers and for Class I power transformers shall be selected from this table for both the high-voltage and the low-voltage windings.
  (5)   The BIL serves both as a test level for the full-wave lightning impulse tests and as the primary identity of a set of coordinated insulation levels.

Table 5-13: Dielectric Insulation for Class II Power Transformers.*
Ref. IEEE Std. C57.12.00-1993, Table 5. Copyright © 1993. IEEE. All rights reserved.

Nominal System Voltage (kV)	Basic Lightning Impulse Insulation Level (BIL) (kV crest)	Chopped-Wave Level (kV crest)	Switching Impulse Level (BSL) (kV crest)	Induced-Voltage Test (Phase-to-Ground)		Applied Voltage Test Level (kV rms)
				One-Hour Level (kV rms)	Enhancement Level (kV rms)	
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
15 and below	110	120	—	—	—	34
25	150	165	—	—	—	50
34.5	200	220	—	—	—	70
46	250	275	—		—	95
69	250	275	—	—	—	95
115	350	385	280	105	120	140
	450	495	375	105	120	185
	550	605	460	105	120	230
138	450	495	375	125	145	185
	550	605	460	125	145	230
	650	715	540	125	145	275
161	550	605	460	145	170	230
	650	715	540	145	170	275
	750	825	620	145	170	325
230	650	715	540	210	240	275
	750	825	620	210	240	325
	825	905	685	210	240	275
	900	990	745	210	240	395
345	900	990	745	315	360	395
	1050	1155	870	315	360	460
	1175	1290	975	315	360	520
500	1300	1430	1080	475	550	—
	1425	1570	1180	475	550	—
	1550	1705	1290	475	550	—
	1675	1845	1390	475	550	—
765	1800	1980	1500	690	800	—
	1925	2120	1600	690	800	—
	2050	2255	1700	690	800	—

*   See Section 5.10 for a description of Class II power transformers.

NOTES:

    (1)   For chopped-wave tests, the minimum time to flashover shall be 3.0 μs except for 110 kV BIL, in which case the minimum time to flashover shall be 2.0 μs.

    (2)   Although Column 4 established phase-to-ground switching impulse levels, it is not always possible to test these levels on low-voltage windings.

    (3)   Columns 5 and 6 provide phase-to-ground test levels that would normally be applicable to wye windings. When the test voltage level is to be measured phase-to-phase, as is normally the case with delta windings, then the levels in Column 5 have to be multiplied by 1.732 to obtain the required phase-to-phase induced-voltage test level.

    (4)   The applied-voltage test is not applicable to wye-winding line terminals unless they have been specified to be suitable for application on ungrounded systems.

    (5)   The insulation levels for Class II power transformers shall be selected from this table for both the high-voltage and the low-voltage windings.

Properly applied surge arresters are very effective in limiting the magnitude of both impulse and switching surge voltages reaching the transformer to levels below their withstand capabilities. Reduced transformer BIL levels are often possible, at appreciable cost reduction, while still maintaining adequate protective margins. Section 5.8 on surge arresters contains additional information on the subject.

Transformers may be exposed to abnormal power frequency voltages during system fault conditions. Single-phase-to-ground faults produce abnormal voltages to ground on the unfaulted phases. The amount that these voltages increase above normal depends on how solidly the system is grounded. With adequate BILs and surge arrester ratings, these temporary abnormal voltages should present no difficulty for the transformer.

External porcelain insulation on a transformer is designed to withstand voltages to which it may be subjected under varied atmospheric conditions. Severe atmospheric contamination may require increased bushing BILs, increased porcelain creep distances, special porcelain treatment, or washing procedures. Local experience under similar conditions is usually the best guide as to the most practical solution.

Standard transformer external insulation is based on applications below 1,000 meters (3300 feet). Above 1,000 meters, the lower air density offers less voltage withstand capability, and the external insulation level has to be derated. Normal ratings are decreased approximately 10 percent for each 1,000-meter increase in elevation above 1,000 meters. See Table 5-1 and ANSI Std. C76.1, "Outdoor Apparatus Bushings," Table 3.2.1(c), for standard derating factors. Choose equipment of a suitably higher rating if derating at high altitude is to be avoided.

5.2.9   Short Circuit Requirements

Failures of substation transformers because of through-fault currents have been a matter of great concern to the industry for many years. The use of larger transformers and the increases in system fault current contributed to the cause of failures. Transformer manufacturers and industry standards began to address the issue of transformer through-fault capabilities in more detail. The standards were expanded along with extensive testing to determine an accurate model of both the thermal and mechanical withstand capabilities of transformers of various sizes. Cooperatives and their engineers should be aware of this problem and should take appropriate measures to safeguard their interests in purchases of power transformers.

5.2.9.1   Background Information: The current edition of ANSI/IEEE Std. C57.12 defines the requirements for transformers of various sizes with respect to short-circuit withstand capabilities during any type of external fault. In addition, ANSI/IEEE Std. C57.109 further defines the transformer capabilities in terms of current versus time characteristics to allow proper coordination with transformer overcurrent protection. ANSI/IEEE Std. C57.12.90 now includes an entire section on short-circuit testing of transformers.

In brief, the standard requires the application of six short circuits at maximum current, two of which would result in maximum asymmetry of the fault current based on the reactance to resistance (x/r) ratio to the point of the fault as defined in ANSI/IEEE Std. C57.12.00, Section 7. The transformer should show no damage after this test as indicated by measurements and visual inspections. For a complete description of the test, refer to ANSI/IEEE Std. C57.12.90, "Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers and Guide for Short Circuit Testing of Distribution and Power Transformers."

The user has to still decide whether to require this test in the purchase specifications. Manufacturers' facilities or test laboratories may be limited in terms of the size of transformer that can be short-circuit tested. Larger sizes conceivably could be tested in the field by the purchaser, but the feasibility of doing so on an operating system is questionable. The laboratory test is fairly costly, and shipping costs

to and from the laboratory test facility should be added. The extra shipping and handling would also subject the transformer to a greater risk of transportation shock damage and human error.

5.2.9.2   Recommendations : Single-phase transformers 10,000 kVA (OA) and smaller, rated 138 kV and below, and three-phase transformers 30,000 kVA (OA) and smaller, rated 138 kV and below, are included in RUS IP 202-1. Cooperatives need not require short-circuit tests for transformers in this category. RUS will either request manufacturers to conduct short-circuit tests on any new transformer design proposed for listing or will request evidence that the transformer design has had a history of successful experience in service. The cooperative should not specify unusual taps or impedance in the purchase specification unless absolutely necessary. Such requirements may cause design changes that will affect mechanical strength and introduce uncertainties in the ability of the transformer to withstand short-circuit currents.

Specifications for transformers not included in the List of Materials[*] should include requirements for short-circuit strength. The manufacturer should be required to demonstrate this strength either directly through previous short-circuit testing of a similar unit or indirectly through a history of successful field experience.

It should be recognized that short-circuit testing will not be feasible on the larger sizes of transformers because of the limitations of existing laboratory facilities. Hence, successful experience will be the principal means for measuring the adequacy of short-circuit strength of these transformers. In this respect, it is recommended that experience be accepted as a demonstration that the transformer design has adequate short-circuit strength. This applies only when transformers with core and coils identical in all respects to the transformer covered by the specifications have amassed a total of at least 20 transformer years of experience without major failure attributable to design defects.

Where the manufacturer has not built units identical to the transformer covered by the specification, or the experience record is less than 20 transformer years, it is recommended that short-circuit testing be required by the specifications or a different manufacturer be selected.

5.2.9.3   Recommended Specification for Short-Circuit Strength: It is recommended that the following be incorporated in all purchase specifications for power transformers not included in the List of Materials:

> "Without limiting in any way any obligation of the Bidder under this agreement, the Bidder shall demonstrate to the satisfaction of the Owner that the transformer proposed to be furnished under this specification shall have sufficient mechanical strength to withstand without failure all through-fault currents. The Bidder shall demonstrate that the transformers meet this requirement by one of the following methods:
>
> 1.   Certified test data showing that a transformer with a core and coil identical in design and construction and identical or similar with respect to kVA capacity, kV ratings, BIL,

---

[*] Transformers not included in RUS IP 202-1, List of Materials:

1. All substation power autotransformers
2. All transformers having three or more windings
3. Single-phase transformers rated greater than 10,000 kVA (OA) or 138 kV

impedance, and voltage taps has been tested under maximum short-circuit conditions without failure. A description of the test code under which the transformer was tested for short-circuit strength will be provided by the Bidder to the Owner.

2.   A history of successful experience with transformers of identical or similar ratings, design, and construction. The Bidder shall list all transformers in service with core and coils that are essentially identical in design, construction, and manufacture to the transformer covered by this specification and shall provide information on the date of installation, location, and failures, if any. Where such transformers have not been built or the cumulative service record is less than 20 transformer years, a list of transformers in service that represent the closest approximation to the transformer covered by this specification shall be submitted. The information submitted shall be representative of the total experience of the manufacturer with similar design to the transformer to be furnished. Information submitted shall include the dates of installation (or shipment, if not installed), the ratings of the transformers, and a list of failures and causes of failures if any have been experienced."

Autotransformers or conventional multiwinding transformers often have special application and design requirements. In such cases, it will be important to provide system short-circuit information indicating the most severe short-circuit condition that can exist at the terminals of each transformer winding, and any specific impedance requirements.

5.2.10 Cooling Equipment

Most of the smaller substation power transformers on rural systems are the oil-immersed, self-cooled (OA) type. In these types of transformers, the oil transfers the heat from the core and coils to the tank wall or cooling tubes, where it passes to the surrounding air. Temperature differences in the oil cause the oil to circulate by convection through the tubes. Adequate airflow is essential to satisfactory operation.

On larger transformers, this cooling process can be accelerated by various methods: using forced air (FA) from fans over the cooling tubes, by using oil pumps to circulate the oil, or by a combination of forced air and forced oil. Both methods can be automatically controlled in one or two steps from either top oil temperatures or winding temperature or both. Forced cooling methods are usually effective in reducing costs of the larger transformer sizes.

Where any type of forced cooling is relied on, it is essential that attention be given to adequate operational reliability of the pumps and fans. This involves consideration of redundancy in the power supply to the pumps and fans and to individual or group overload protection and disconnecting means. Also, hot spot and top oil temperature devices can be used to alarm for abnormal cooling indications. The temperature limits should be specified to adequately protect the unit but not to limit its overload capability. Suggested alarm limits are listed in Table 5-14:

Table 5-14: Alarm Limits for Transformer Cooling

	55°C Insulation	65°C Insulation
Hottest Spot Temperature	95°C	105°C
Top Oil Temperature	70°C	80°C

The cooling tubes or heat exchangers on large transformers should be specified for easy removal or isolation from the transformer for repairs. In this case, shutoff valves and bolted flanges are provided at the inlet and outlet of each heat exchanger. Transformers below a range of 10,000 kVA, three-phase, and 5,000 kVA, single-phase, usually have nonremovable cooling tubes. These kVA sizes will vary between manufacturers.

5.2.11 Oil and Oil Preservation Equipment

Transformer oil has to be kept free from contact with outside contaminants always present in the atmosphere. On smaller substation transformers, the tank is completely sealed, with a layer of dry air or nitrogen left above the oil to accommodate expansion and contraction of the oil.

Several methods of oil preservation (see Figure 5-1) are commonly used on larger size transformers:

1. A sealed tank with a positive pressure inert gas layer maintained above the oil by means of a permanently connected tank of nitrogen gas
2. A tank completely filled with oil but connected to a raised tank or oil conservator, which maintains a positive oil pressure in the main tank and provides a place for expansion and contraction of the oil
3. A conservator tank with a divided expansion tank with two sections and the flexible diaphragm conservator tank
4. A conservator tank with a bladder within the conservator tank as a variation of the flexible diaphragm

The choice of oil preservation system is mostly a matter of personal preference and experience. All have been successfully used for many years. Regardless of the method used, periodic tests have to be made of the oil and oil preservation system to ensure that oil quality is being maintained.

5.2.12 Audible Sound

Sound (noise) levels produced by transformers, as well as other substation equipment, are becoming a matter of increasing concern to the public. The fact that rural substations are more often located away from congested areas reduces the possibility of complaints. However, this is partially offset by the lower ambient sound levels common in rural areas.

In some areas, noise ordinances may dictate what is required. The designer should accordingly be familiar with the problems and their solutions. A thorough treatment of the subject is beyond the scope of this bulletin, but some practical guidelines follow. Any values given should be treated as approximations.

5.2.12.1   **Site:** Sound is usually transmitted radially from the source. Avoid sites that have a direct line of sight to possible areas of complaints. A particularly poor selection would be a low-level site with residential areas on the surrounding higher ground.

5.2.12.2   **Landscape**: Natural or artificial barriers such as mounds or shrubbery positioned between the sound source and the public are desirable. Although these have little effect on sound levels, they can reduce the psychological impact of a new substation and prevent complaints.

POSITIVE PRESSURE/ INERT GAS

INERT GAS SPACE
(POSITIVE PRESSURE)

CONNECTING TUBE

REDUCING VALVE

HIGH-PRESSURE TANK
OF INERT GAS

OIL
LEVEL
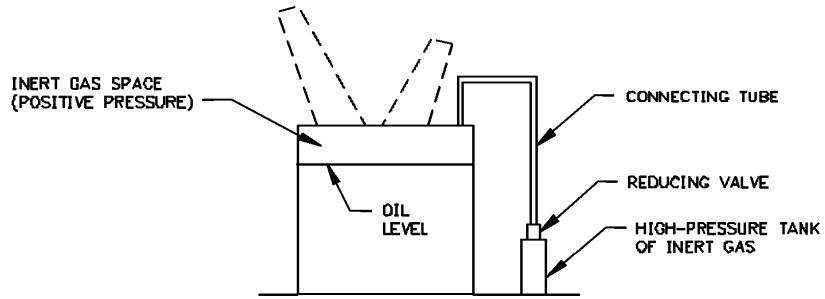
OIL CONSERVATOR – DIVIDED TANK

CONSERVATOR
TANK

OIL
LEVEL

TUBE (OIL CONNECTION)

MAIN TANK
FULL OF OIL
UNDER SLIGHT
PRESSURE

ATMOSPHERIC
PRESSURE

BAFFLE

DEHYDRATING
BREATHER

CONSERVATOR
TANK DETAIL

OIL LEVEL

A

TUBE

TO MAIN
TANK

CONNECTION BETWEEN
TANK SECTIONS WAS
FILTERED TO PREVENT
ENTRY OF ATMOSPHERIC
CONTAMINANTS
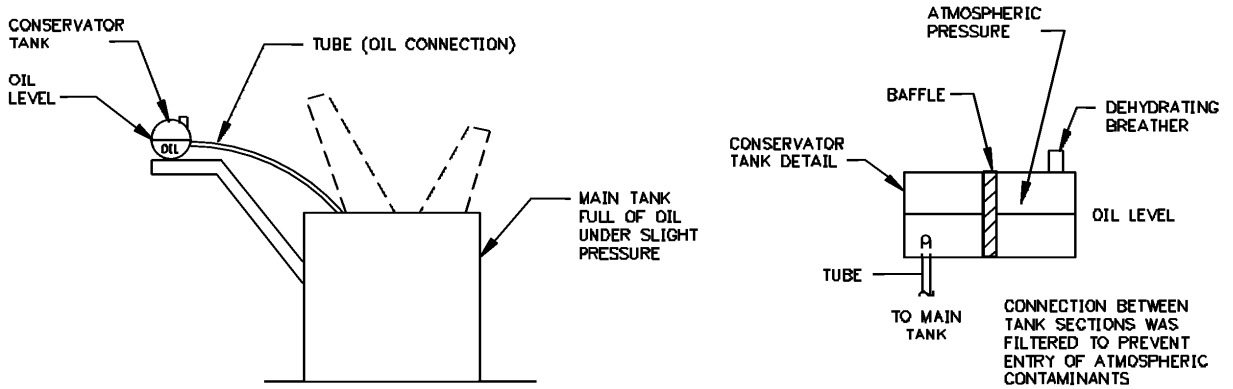
OIL CONSERVATOR – WITH FLEXIBLE DIAPHRAM

ATMOSPHERIC PRESSURE

DEHYDRATING BREATHING TUBE

FLEXIBLE
DIAPHRAM

(ALTERNATE BALLOON
BAG WITHIN THE
CONSERVATOR TANK)

MAIN TANK
FULL OF OIL
UNDER SLIGHT
PRESSURE

TUBE (OIL
CONNECTION)

FLEXIBLE DIAPHRAM SEALS OIL FROM ATMOSPHERE.
FLEXIBILITY OF DIAPHRAM PERMITS EXPANSION
AND CONTRACTION OF OIL. A VARIATION OF THIS
PRINCIPLE USES AN AIR CELL WITHIN THE ELEVATED
TANK   THE AIR CELL IS CONNECTED TO THE
ATMOSPHERE AND EXPANDS OR CONTRACTS WITH
TERMINAL CYCLING OF THE OIL.

Figure 5-1: Methods of Oil Preservation

5.2.12.3   Distance: Sound levels are attenuated with distance. Approximately a 6-dBA reduction can be obtained with each doubling of the distance between source and point of measurement.

5.2.12.4   Sound Levels: Standard sound levels for transformers are listed in NEMA Std. TR1. See Tables 5-15 (see page 213 of this bulletin), 5-16, and 5-17. Reduced sound level transformers may increase the transformer cost approximately 1 ½ percent for each dBA reduction from these NEMA standard levels. Actual price variations for different sound levels can only be determined in a bid process when all other design factors are considered. Transformer sound levels tend to increase with BIL, kVA, and the number of stages of cooling. A practical limit in designing special low-sound-level transformers is approximately a 12-dBA reduction where forced cooling is required. Greater reductions require expensive measures, such as double-wall tanks.

Table 5-16: Audible Sound Levels for Liquid-Immersed Distribution Transformers
and Network Transformers. Ref. NEMA TR1-1993, Table 0-3.
Reproduced with permission of the National Electrical Manufacturers Association.

Equivalent Two-Winding kVA	Average Sound Level, Decibels
0-50	48
51-100	51
101-300	55
301-500	56
750	57
1000	58
1500	60
2000	61
2500	62

Table 5-17: Audible Sound Levels for Dry-Type Transformers, 15 000-Volt
Nominal System Voltage and Below. Ref. NEMA TR1-1993, Table 0-4.
Reproduced with permission of the National Electrical Manufacturers Association.

Equivalent Two-Winding kVA	Average Sound Level, Decibels		Equivalent Two-Winding kVA	Average Sound Level, Decibels Ventilated Forced Air Cooled**, †
	Self-Cooled Ventilated*	Self-Cooled Sealed*		
0-50	50	50	—	—
51-150	55	55	—	—
151-300	58	57	3-300	67
301-500	60	59	301-500	67
501-700	62	61	501-833	67
701-1000	64	63	834-1167	67
1001-1500	65	64	1168-1667	68
1501-2000	66	65	1668-2000	69
2001-3000	68	66	2001-3333	71
3001-4000	70	68	3334-5000	73
4001-5000	71	69	5001-6667	74
5001-6000	72	70	6668-8333	75
6001-7500	73	71	8334-10000	76

*   Class AA rating.
**   Does not apply to sealed-type transformers.
†   Class FA and AFA ratings.

Table 5-15: Audible Sound Levels for Oil-Immersed Power Transformers. REF. NEMA TR1-1993, Table 0-2.
Reproduced with permission of the National Electrical Manufacturers Association.

Column 1 – Class* OA, Ow, and FOW Ratings
Column 2 – Class* FA and FOA First-Stage Auxiliary Cooling**†
Column 3 – Straight FOA* Ratings, FA* FOA* Second-Stage Auxiliary Cooling*†

Average Sound Level †† Decibels	Equivalent Two-Winding Rating																	
	350 kV BIL and Below			450, 550, 650 kV BIL			750 and 825 kV BIL			900 and 1050 kV BIL			1175 kV BIL			1300 kV BIL and Above		
	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
57	700	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
58	1000	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
59	--	--	--	700	--	--	--	--	--	--	--	--	--	--	--	--	--	--
60	1500	--	--	1000	--	--	--	--	--	--	--	--	--	--	--	--	--	--
61	2000	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
62	2500	--	--	1500	--	--	--	--	--	--	--	--	--	--	--	--	--	--
63	3000	--	--	2000	--	--	--	--	--	--	--	--	--	--	--	--	--	--
64	4000	--	--	2500	--	--	--	--	--	--	--	--	--	--	--	--	--	--
65	5000	--	--	3000	--	--	--	--	--	--	--	--	--	--	--	--	--	--
66	6000	--	--	4000	--	--	3000	--	--	--	--	--	--	--	--	--	--	--
67	7500	6250	--	5000	3750	--	4000	3125	--	--	--	--	--	--	--	--	--	--
68	10000	7500	--	6000	5000	--	5000	3750	--	--	--	--	--	--	--	--	--	--
69	12500	9375	--	7500	6250	--	6000	5000	--	--	--	--	--	--	--	--	--	--
70	15000	12500	--	10000	7500	--	7500	6250	--	--	--	--	--	--	--	--	--	--
71	20000	16667	--	12500	9375	--	10000	7500	--	--	--	--	--	--	--	--	--	--
72	25000	20000	20800	15000	12500	--	12500	9375	--	--	--	--	--	--	--	--	--	--
73	30000	26667	25000	20000	16667	--	15000	12500	--	12500	--	--	--	--	--	--	--	--
74	40000	33333	33333	25000	20000	20800	20000	16667	--	15000	--	--	12500	--	--	--	--	--
75	50000	41687	41667	30000	26667	25000	25000	20000	20800	20000	16667	--	15000	--	--	12500	--	--
76	60000	50000	50000	40000	333333	33333	30000	26667	25000	25000	20000	20800	20000	16667	--	15000	--	--
77	80000	66667	66667	50000	40000	41667	40000	33333	33333	30000	26667	25000	25000	20000	20800	20000	16667	--
78	100000	83333	83333	60000	53333	50000	50000	40000	41667	40000	33333	33333	30000	26667	25000	25000	20000	20800
79	--	100000	100000	80000	66667	66667	60000	53333	50000	50000	40000	41667	40000	33333	33333	30000	26667	25000
80	--	133333	133333	100000	80000	83333	80000	66667	66667	60000	53333	50000	50000	40000	41667	40000	33333	33333
81	--	--	166667	--	106667	100000	100000	80000	83333	80000	66667	66667	60000	53333	50000	50000	40000	41667
82	--	--	200000	--	133333	133333	--	106667	100000	100000	80000	83333	80000	66667	66667	60000	53333	50000
83	--	--	250000	--	--	166667	--	133333	133333	--	106667	100000	100000	80000	83333	80000	66667	66667
84	--	--	300000	--	--	200000	--	--	166667	--	133333	133333	--	106667	100000	100000	80000	83333
85	--	--	400000	--	--	250000	--	--	200000	--	--	166667	--	133333	133333	--	10667	100000
86	--	--	--	--	--	300000	--	--	250000	--	--	200000	--	--	166667	--	133333	133333
87	--	--	--	--	--	400000	--	--	300000	--	--	250000	--	--	200000	--	--	166667
88	--	--	--	--	--	--	--	--	400000	--	--	300000	--	--	250000	--	--	200000
89	--	--	--	--	--	--	--	--	--	--	--	400000	--	--	300000	--	--	250000
90	--	--	--	--	--	--	--	--	--	--	--	--	--	--	400000	--	--	300000
91	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	400000

* Classes of cooling (see 2.6.1 of American National Standard C57.12.00-1988).
** First- and second-stage auxiliary cooling (see TR 1.0.02).
† For column 2 and 3 ratings, the sound levels are with the auxiliary cooling equipment in operation.

†† For intermediate kVA ratings, use the average sound level of the next larger kVA rating.
The equivalent two-winding 55℃ or 65℃ rating is defined on one-half the sum of the kVA of all windings.
Sixty-seven decibels for all kVA ratings equal to this or smaller

Required sound levels in dBs (based on the ANSI weighting network "A" response or dBA scale) will vary from one situation to another. Levels sometimes prescribed in ordinances may be approximately 45 dB at night and 55 dB in daytime. These levels may apply only to a potential source of complaint or at the substation boundaries. For comparison, a NEMA-standard-designed 20,000 kVA two-winding substation transformer with 350 kV BIL and first stage of auxiliary cooling would have an average sound level of 72 dB. (See Pedersen 1956; Schulz 1976.)

5.2.12.5   Barriers: Sound barriers located near the transformer can be considered in special cases (especially at existing installations) as a means of reducing noise levels in the vicinity. Barriers can produce a maximum reduction of approximately 20 dB. A total enclosure can produce a 40-dB reduction. For partial barriers, a reduction of 15 dB is a practical maximum. The effect of the barriers on transformer cooling and transformer removal should also be considered.

5.2.13 Tank

In most cases, the manufacturer's standard provisions related to the transformer tank will meet requirements for filling and draining, oil sampling, handling, internal inspection, etc. Any special requirements or preferences should be considered at the time specifications are written and their possible extra cost evaluated. Some items to consider are:

- Preferred location of heat exchangers
- Preferred location and height of cabinets and other accessories above transformer base
- Construction of terminal boards
- Paint color
- Provisions for future additions

5.2.14 Accessories

Various accessories are available for use with power transformers. Many of these are standard items normally supplied with the basic transformer while others are special items available at extra cost. Items supplied as standard are listed in ANSI/IEEE Std. C57.12.10, Section 5. Some accessories not furnished as standard items but that may be desired are special bushings, current transformers, bushing capacitance potential taps, bushing potential device(s), auxiliary power provisions, special relays, special terminals, spare parts, etc.

5.2.15 Electrical Tests and Measurements

5.2.15.1   Dielectric Tests: Dielectric tests consist of a variety of tests, each performed to prove a certain characteristic of the transformer insulation structure. (See ANSI/IEEE Stds. C57.12.90 and C57.98 for complete information on tests.) Dielectric tests are generally specified only on the larger sizes of transformers or on smaller transformers used in especially important applications. Most manufacturers charge for these tests. Table 5-18 provides guidelines for specifying dielectric tests.

5.2.15.1.1   Full Wave Impulse Test: The full wave impulse test (1.2 x 50-microsecond wave) is designed to simulate a lightning stroke. Because of its relatively long duration, the full wave impulse test causes major oscillations to develop in the winding. Consequently, not only turn-to-turn and section-to-section insulation are stressed throughout the winding but relatively high voltages can result, compared to power frequency stresses, across large portions of the winding and between the winding and ground (core and adjacent windings).

Table 5-18: Guidelines for Specification of Dielectric Tests
on Power Transformers Rated 345 kV and Below

	10,000 kVA (OA) or Less Mfr's Quality Assurance Only*	Above 10,000 kVA (OA) Purchaser's Specifications**
Reduced Full Wave	Yes	Yes
Chopped Wave (2 shots)	Yes	Yes
Full Wave	Yes	Yes
Low-Frequency Tests	Yes	Yes
Partial Discharge (Internal Corona)	Usually None	Yes

*   Manufacturers' practices regarding quality assurance tests will vary from one manufacturer to another. When these tests are performed, no official report is provided to the customer.
** Purchaser's Specification should specify that the dielectric tests shall be performed in accordance with ANSI Standards. An official manufacturer's report should be required.

5.2.15.1.2   Chopped Wave Impulse Test: The chopped wave impulse test (similar to the full wave test but 15 percent higher and chopped on the tail in about 3 µs or less), because of its shorter duration, does not allow the major oscillations to develop as fully. It is designed to simulate a lightning stroke truncated by a flashover on an adjacent portion of the insulation system. This test generally does not produce as high voltages across large portions of the winding or between the winding and ground. However, because of its greater amplitude, it produces high voltages at the line end of the winding and, because of the rapid change of voltage following flashover of the test gap, it produces higher turn-to-turn and section-to-section stresses.

5.2.15.1.3   Front-of-Wave Impulse Test: The front-of-wave impulse test (similar to the chopped wave test but chopped on the front and with a much steeper front) is still shorter in duration and produces still lower winding-to-ground voltages deep within the winding. Near the line end, however, its greater amplitude produces higher voltages from winding to ground, and this, combined with the rapid change of voltage on the front and following flashover, produces high turn-to-turn and section-to-section voltages near the line end of the winding.

5.2.15.1.4   Switching Surge Test: The switching surge test is related to the other impulse tests, but has a much longer wave front and tail. This slow wave fully penetrates the windings and stresses all parts of the insulation structure.

5.2.15.1.5   Applied Voltage Test: An applied voltage test measures the ability of the transformer to survive at normal frequency overvoltage. It also determines the increase in exciting current.

5.2.15.1.6   Induced Voltage Test: An induced voltage test measures the insulation strength between turns in the winding and the insulation strength of barriers and other major insulation between phases. During this test, a partial discharge (corona) test can be conducted to determine presence, inception, and extinction levels of partial discharges that may be damaging to the insulation structure and eventually lead to failure.

The partial discharge (corona) test consists of measuring the 1 megahertz (by agreement between manufacturers and users) portion of any pulses produced within the transformer during low-frequency

tests and that show up at the transformer terminals. The low-frequency tests are usually performed using 120 to 240 hertz voltages. The magnitude of the partial discharge is expressed in microvolts.

Most manufacturers take the measurements from each bushing capacitance tap, when these taps are available. A calibration procedure is used to convert the tap readings to an equivalent value at the bushing terminal.

5.2.15.2   Measurements (Electrical): Measurements that produce data required for operation of the transformer include resistance, core and conductor losses, excitation current, impedance, ratio and regulation temperature rise, insulation power factor, polarity and phase relation, etc. Consult ANSI/IEEE Std. C57.12.90 for detailed information regarding these test measurements.

5.2.16 Shipment

Several shipping considerations are important. During shipping, the transformer may be subjected to its most severe test due to rough handling. Acceleration measuring devices (impact recorder) mounted on the transformer during shipment will help to determine whether the transformer may have been subjected to excessive forces. In any case, make a thorough inspection of the interior of the transformer to determine whether movement of the core and coils has taken place or whether evidence of any other damage exists.

Larger size transformers are shipped without oil but sealed with either a blanket of nitrogen gas or dry air. The method used often varies with the transformer manufacturer. Either method is considered satisfactory, provided proper safety precautions are taken and warning signs are exhibited to deter a person from entering an unsafe tank before it has been purged with proper amounts of air or oxygen.

It is good practice to provide the manufacturer with all necessary information regarding the situation at the final destination. This will enable shipment to be made in the most convenient way. Sometimes it is important for the transformer to be positioned a particular way by the final carrier to facilitate unloading at the site.

5.2.17 Warranty

In general, transformer manufacturers warrant their product to be free of defects in workmanship and material for a specified period. In the event of a defect, the manufacturer may elect to correct the problem at his option either by repairing the defective part or parts or by supplying a repaired or replacement part or parts. Under terms of a normal warranty, the manufacturer assumes no responsibility for disassembly or reassembly of the equipment or return transportation from the field to the factory and back to the field.

Since warranties are subject to many variables, the purchaser is cautioned to exercise care in review and evaluation of each one. Warranty periods vary from one to five years or more. Special warranties are available, at some increase in purchase price, that extend the warranty period and/or include the cost of removing a failed transformer from the field, returning it to the factory, repair, return to the field, reinstallation in the field, etc.

5.2.18 Core and Coils

Transformers can be classified by two different forms of construction: "core form" or "shell form." Most common is the core-form type manufactured either with cylindrical coils wrapped horizontally around a cylindrical core or with rectangular coils and a rectangular core. Core-form transformers have excellent

short-circuit capability for most applications. The shell-form transformer is manufactured with the coils wrapped through the core vertically. Shell-form transformers were developed for very large, high-magnitude short-circuit application such as generator step-up transformers.

5.2.19 Specifications

Purchase specifications should be based on standards of national organizations such as ANSI, IEEE, NEMA, etc. However, when the desired power transformer is included in RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers," specification need only cover such details as voltage, kVA ratings, optional tests, and features or accessories that are offered by the manufacturer and considered necessary or desirable. The basic requirements for transformers in the List of Materials are given in the ANSI/IEEE Standards C57 series and should not be included in the purchase specification. The latest List of Materials includes step-down power transformers in the following sizes and voltage ratings:

	Primary Voltage Rating	Capacity, kVA
Single-Phase	138 kV and below	10,000 kVA (OA) and below
Three-Phase	138 kV and below	30,000 kVA (OA) and below

Purchase specifications for transformers that are not included in the List of Materials should be detailed enough to provide reasonable assurance that the transformer will be suitable for its intended use. In general, the specification should be based on functional and operational requirements rather than construction and design requirements, since the latter are properly the responsibility of the manufacturer. It is very important that the user review the "usual" and "unusual" operating conditions listed in "General Requirements Standards" such as ANSI/IEEE Std. C57.12.00 and ANSI/IEEE C57.12.01. Any unusual or special operating or environmental condition should be made known to the manufacturer.

It is recommended that the purchase specifications be modeled on or checked against the requirements of ANSI Std. C57.97, "Guide for Preparation of Specifications for Large Power Transformers, With or Without Load Tap Changing." In addition, it is recommended that a special requirement for short-circuit current strength be included such as given in Section 5.2.9, Short-Circuit Requirements. The manufacturer's standard design should be accepted, and standard sizes, ratings, taps, and accessories should be specified, unless there is a good reason for doing otherwise.

To assist in the evaluation of transformers being offered in a particular case, it is desirable to include in the request for bids the method for evaluation of transformer losses. This should be patterned after RUS Bulletin 1724E-301, "Guide for the Evaluation of Large Power Transformer Losses." This information will also assist the manufacturer in its efforts to offer the type of transformer desired.

5.2.20 References

ANSI Std. C57.12.10, "Safety Requirements 230 kV and Below 833/958 Through 8333/10 417 kVA, Single-Phase, and 750/862 Through 60 000/80 000/100 000 kVA, Three-Phase Without Load Tap Changing."

ANSI Std. C57.12.20, "Transformers Overhead-Type Distribution Transformers, 500kVA and Smaller: High Voltage, 34 500 Volts and Below; Low Voltage, 7970/13 800Y Volts and Below," 1988.

ANSI Std. C57.12.21, "Requirements for Pad-Mounted Compartmental-Type Self-Cooled Single-Phase Distribution Transformers with High-Voltage Bushings (High-Voltage, 34 500 Grd Y/19 920 Volts and Below; Low Voltage, 240/210; 167 kVA and Smaller)," 1980.

ANSI Std. C57.12.22, "Requirements for Pad-Mounted Compartmental-Type, Self-Cooled Three-Phase Distribution Transformers with High-Voltage Bushings, 2500 kVA and Smaller: High-Voltage, 34 500 Grd Y/19 920 Volts and Below; Low Voltage, 480 Volts and Below," 1988.

ANSI Std. C57.12.23, "Standard for Transformers—Underground-Type, Self-Cooled, Single-Phase Distribution Transformers with Separable, Insulated High-Voltage Connectors: High Voltage (24 940 Grd/ 14 400 Volts and Below) and Low Voltage (240/120 Volts, 167 kVA and Smaller)," 1986.

ANSI Std. C57.12.24, "Standard for Transformers—Underground-Type, Three-Phase Distribution Transformers, 2500 kVA and Smaller: High Voltage 34 500 Grd Y/19 920 Volts and Below; Low Voltage, 480 Volts and Below—Requirements," 1992.

ANSI Std. C57.12.25, "Requirements for Pad-Mounted Compartmental-Type Self-Cooled Single-Phase Distribution Transformers with Separable Insulated High-Voltage Connectors, High-Voltage, 34 500 Grd Y/19920 Volts and Below; Low-Voltage, 240/210; 167 kVA and Smaller," 1990.

ANSI Std. C57.12.26, "Requirements for Pad-Mounted Compartmental-Type Self-Cooled Three-Phase Distribution Transformers with Separable Insulated High-Voltage Connectors, High-Voltage, 34500 Grd Y/19920 Volts and Below; 2500 kVA and Smaller," 1992.

ANSI Std. C57.12.70, "Terminal Markings and Connections for Distribution and Power Transformers."

ANSI Std. C57.97, "ANSI Guide for Preparation of Specifications for Large Power Transformers, With or Without Load Tap Changing."

ANSI Std. C76.1, "Outdoor Apparatus Bushings."

ANSI Std. C84.1, "Electric Power Systems and Equipment—Voltage Ratings."

ANSI Std. C92-2, "Preferred Voltage Ratings of Alternating-Current Electrical Systems and Equipment Operating at Voltages Above 230 kV Nominal," 1987.

ANSI/IEEE Std. C57.10.101, "Draft, Trial-Use Guide for Loading Power Apparatus Bushings."

ANSI/IEEE Std. C57.12.00, "Distribution, Power and Regulating Transformers, General Requirements for Liquid-Immersed."

ANSI/IEEE Std. C57.12.01, "Standard General Requirements for Dry-Type Distribution and Power Transformers."

ANSI/IEEE Std. C57.12.11, "Guide for Installation of Liquid-Immersed Transformers (10 MVA and Larger, 69-287 kV Rating)."

ANSI/IEEE Std. C57.12.80, "Transformer Terminology."

ANSI/IEEE Std. C57.12.90, "Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers and Guide for Short Circuit Testing of Distribution and Power Transformers."

ANSI/IEEE Std. C57.19.00, "Draft, Standard General Requirements and Test Procedure for Outdoor Apparatus Bushings."

ANSI/IEEE Std. C57.19.01, "Draft, Standard Performance Characteristics and Dimensions for Outdoor Apparatus Bushings."

ANSI/IEEE Std. C57.92, "Guide for Loading Mineral Oil-Immersed Power Transformers up to and Including 100 MVA with 55°C or 65°C Average Winding Rise."

ANSI/IEEE Std. C57.98, "Guide for Transformer Impulse Tests."

ANSI/IEEE Std. C57.109, "Guide for Through-Fault-Current Duration."

ANSI/IEEE Std. C57.116, "Guide for Transformers Connected to Generators."

IEEE Std. C57.104, "Draft, Guide for Interpretation of Gases Generated in Oil-Immersed Transformers."

IEEE Std. C57.106, "Draft, Guide for Acceptance and Maintenance of Insulating Oil in Equipment."

NEMA Std. TR1, "Transformers, Regulators and Reactors."

Pedersen, R.S., "Audible Noise Reduction," *Transmission and Distribution*, November 1956.

RUS Bulletin 50-91, "RUS Specification for Step-Down Distribution Substation Transformers."

RUS Bulletin 61-16, "Guide for Economic Evaluation of Distribution Transformers."

RUS Bulletin 1724E-301, "Guide for the Evaluation of Large Power Transformer Losses."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

Schulz, M.W. (Member IEEE, General Electric Company, Schenectady, New York). "Transformer Audible Noise." Presented as part of an IEEE Tutorial Course on "Application of Distribution and Power Transformers" Organized by W.J. McNutt, Fellow, IEEE, General Electric Company, Pittsfield, Mass., April 1976.

5.3 POWER CIRCUIT BREAKERS

5.3.1 General

By definition, a circuit breaker is a device that closes and interrupts (opens) an electric circuit between separable contacts under both load and fault conditions, as prescribed in the C37 series of ANSI Standards. This discussion is limited to circuit breakers rated 1000 volts and above. (Automatic circuit reclosers are discussed in Section 5.9.)

5.3.1.1   Prerequisites to Specification: The application of circuit breakers involves consideration of the intended function, expected results, benefits to the electric system, and characteristics of both the circuit breakers and the electric system. In some instances, protective devices of lesser capability and flexibility, such as fuses, circuit switchers, reclosers, etc., may be more desirable or preferred over more complex and costly circuit breakers.

Fuses are often desirable for transformer protection at any location where they are adequate for the thermal load and short-circuit conditions because of their lower cost and smaller space requirements compared to other devices. They are also desirable for their ease of coordination with circuit breakers and relays at other locations on the electric system. Fuses can also be applied as temporary maintenance bypass protection to permit maintenance of circuit breakers. Fuses are also used extensively for sectionalization and branch circuit protection in distribution systems.

Circuit switchers are less costly than circuit breakers and can be applied in much the same way as circuit breakers, subject to limitations in interrupting capability, with the same type of relay control as circuit breakers. Circuit switchers are also supplied without current transformers (circuit breakers are usually supplied with CTs), which are used in conjunction with relays to sense faults. They can be substituted for fuses in transformer bank protection to detect low-voltage-side faults that fuses may not be able to detect. This detection would utilize relay intelligence from the low-voltage side. Circuit switchers also provide excellent capacitor bank switching and protection. In outlying areas of moderate short-circuit capacity, they can often be substituted for circuit breakers. They can be mounted similarly to air-break switches on a substation structure and thus require little or no additional space.

Reclosers are completely self-contained and provide excellent distribution circuit exit and feeder protection. Their ratings are adequate for both load and short circuit on most distribution circuits and overlap the ratings of more costly circuit breakers. Their operation is faster than most circuit breakers, and their sequence of open and close operations is very flexible. Reclosers are available in both single- and three-phase ratings so that they are very useful and adaptable for the entire distribution system at locations where reclosing operation is required.

Writing of specifications and selection of power circuit breakers and similar devices should be preceded by electric system studies to determine the parameters of application and operation that have to be satisfied. These include load flow, short-circuit, transient voltage, coordination, and protection studies.

5.3.1.2   Specification—General Requirements: Power circuit breakers are not included in RUS's "List of Materials." Therefore, for each application, a detailed specification is necessary. A functional specification describing the circuit breaker rating and control, electric system characteristics and any special requirements is preferred to one describing design and construction details. ANSI Std. C37.12, "American National Standard Guide Specifications for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis and a Total Current Basis," can be used directly as a model or checklist for the purchase specification. A manufacturer's standard design and construction would normally be considered acceptable.

It is recommended that those persons responsible for preparing power circuit breaker specifications become familiar with:

1. The C37 series of ANSI Standards covering ratings, testing, applications, specifications, etc.
2. Each specific application and proposed installation
3. Each prospective supplier's product line of circuit breakers

5.3.2   <u>Types of Circuit Breakers</u>

Breakers are usually classified as "dead tank" or "live tank" construction. "Dead tank" means that the circuit breaker tank and all accessories are maintained at ground potential, and the external source and load connections are made through conventional bushings (see Figure 5-2). "Live tank" means that the metal and porcelain housing containing the interrupting mechanism is mounted on an insulating porcelain column and is therefore at line potential (see Figure 5-3). This column, besides serving as an insulating support, may act as an access for the operating rod or linkage and, in the case of air circuit breakers, it acts as an air supply duct. Most circuit breakers above 242 kV are of "live tank" construction. However, some dead tank-type units are in use.

In addition to classification as "live tank" or "dead tank" construction, circuit breakers are also classified in terms of interrupting media. Breakers are also classified as three-pole, single-throw, and independent-pole operation. Three-pole single-throw breakers utilize one mechanical device to trip all three poles with a linkage to gang the operation together (see Figure 5-4). With independent-pole operation, each pole is equipped with the mechanical means to trip its individual pole (see Figure 5-5). Although availability of different breaker designs is closely related to the state of the art at any particular time, Table 5-19 indicates the known availability of breaker types.

Table 5-19: Types of Circuit Breakers

	Availability vs. Interrupting Media			
Outdoor	*Oil (1)*	*Air*	*Gas*	*Vacuum*
Dead Tank				
Single Tank	X		X	X
Three Tank	X		X	X
Live Tank				
Indoor			X	
Dead Tank	X		X	X

(1) Oil circuit breakers are only available as remanufactured or used equipment.

No general guidelines can be drawn for the application of these various types of circuit breakers. Each user has to determine the ratings of circuit breakers required and then select a type of circuit breaker acceptable with regard to rating, performance expectations, compatibility with planned or existing substation configuration, and the ability to install, operate, and maintain the circuit breaker. Cost may also be an important consideration in the final selection.

Most, but not all, domestic circuit breakers in outdoor substations of 2.4 kV through 24.9 kV utilize a vacuum technology as the insulating dielectric to interrupt load and fault currents (see Figure 5-6).

Although outdoor vacuum breakers can be supplied for voltages up to 38 kV, SF_6 is more commonly used for voltages from 34.5 kV to 765 kV.

Figure 5-2: "Dead Tank" Breaker
(Courtesy of Mitsubishi)
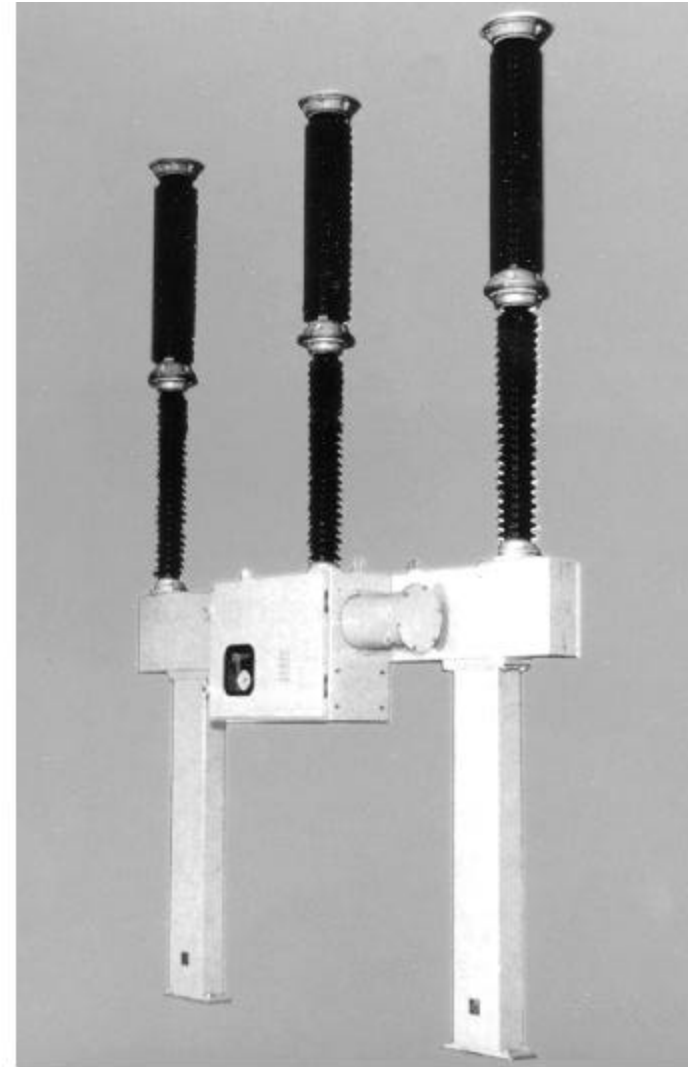
Figure 5-3: "Live Tank" Breaker
(Courtesy of Mitsubishi)
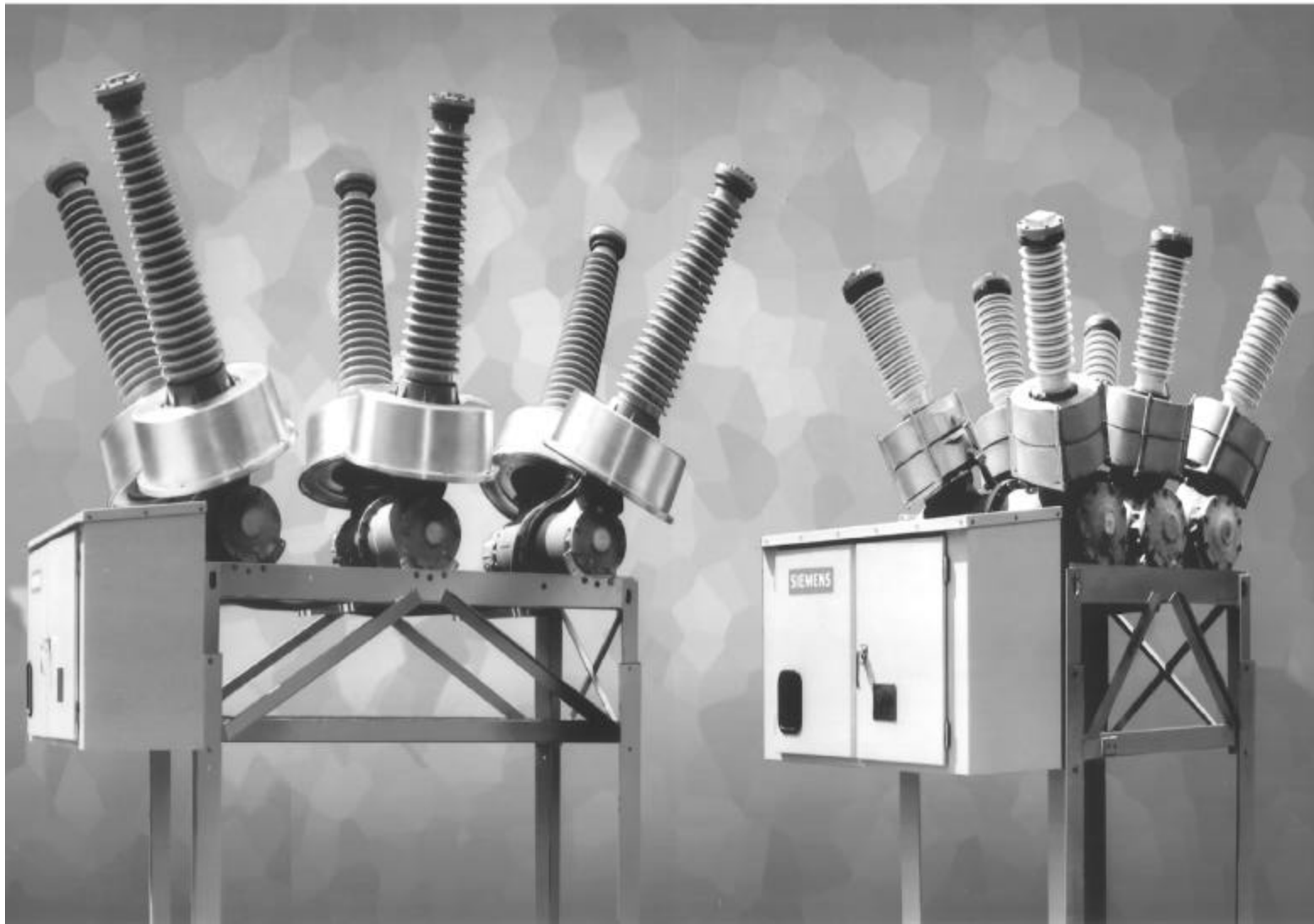
Figure 5-4: Three-Pole Single-Throw Breakers (Courtesy of Siemens)
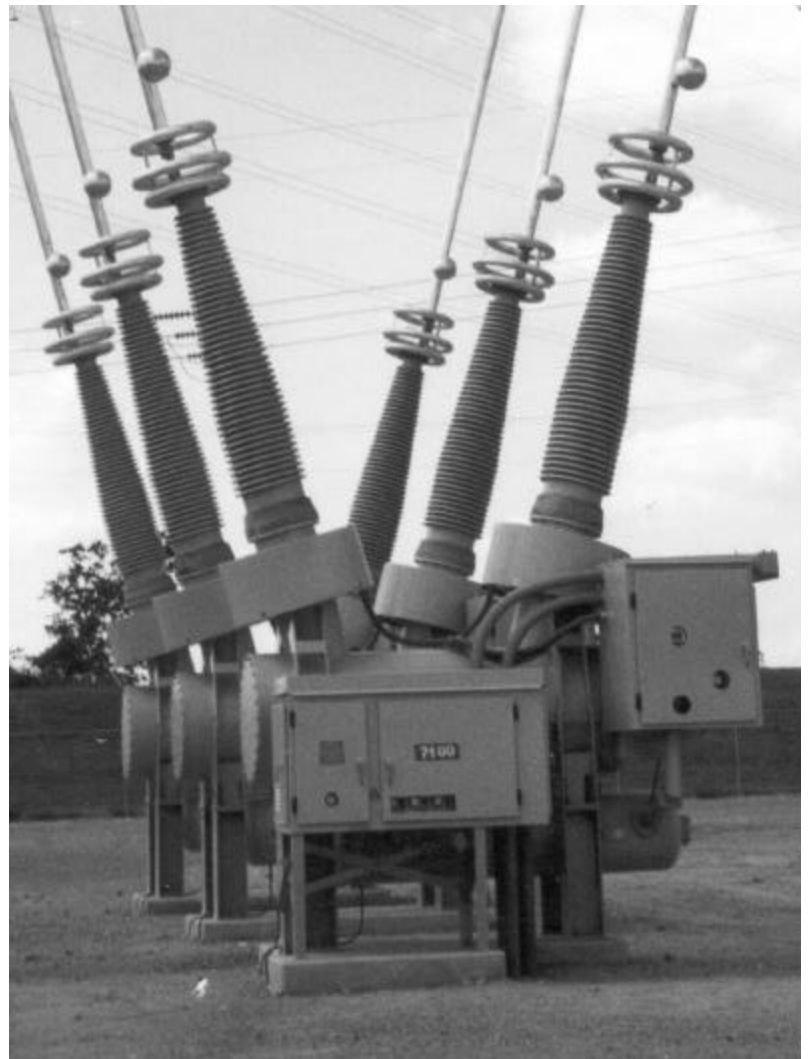
Dimensions	242 kV	362 kV
A	26'-11$^9/_{16}$"	36'-9"
B	10"	15"
C	21'-33$^1/_{16}$"	32'-3$^3/_4$"
D	9'-1$^1/_8$"	9'-$^7/_8$"
E	15'-4$^3/_8$"	18'-7$^5/_{16}$"
F	7'-10$^1/_2$"	11'-2$^{13}/_{16}$"
G	6'-3$^1/_4$"	9'-10$^1/_{16}$"
H	7'	6'-2$^1/_8$"
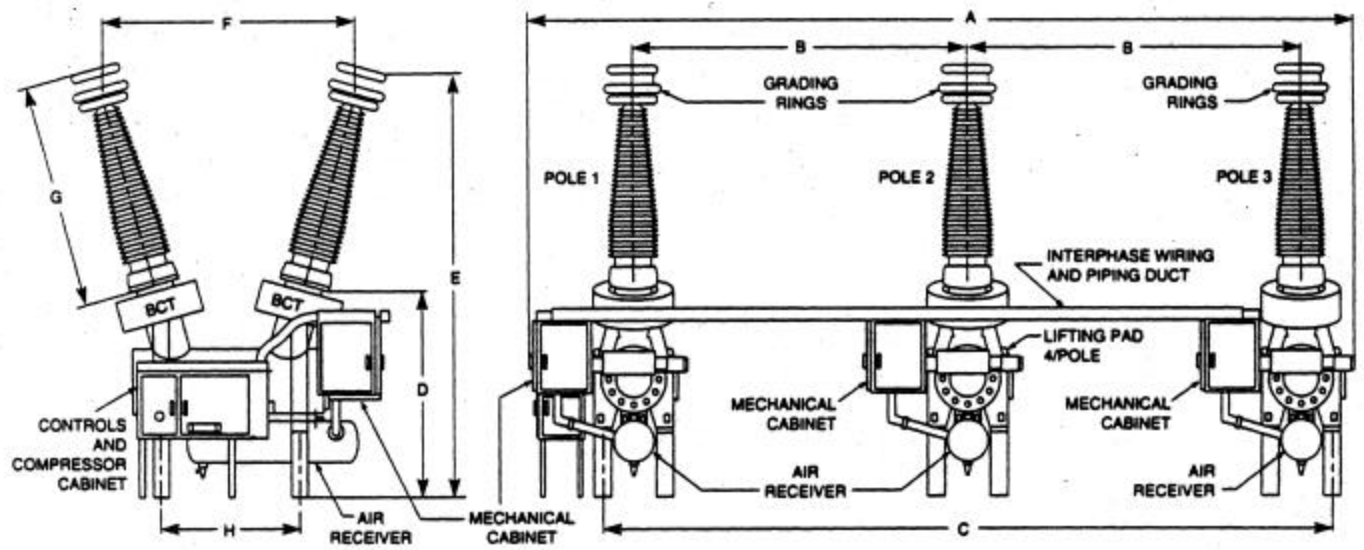
Figure 5-5: SF$_6$ Gas Circuit Breakers (Courtesy of GE-Hitachi HVB, Inc.)

Pole Unit Detail

1. Entrance Bushing
2. High Voltage Cabinet
3. Bushing Current
   Transformer
4. Insulating Strut
5. Vacuum Interrupter
6. Support Insulator
7. Interrupter Support
8. Contact Pressure Spring
9. Belcrank Lever Assembly
10. Insulated Coupler
11. Operator Mechanism
12. Control Compartment Door
13. CT Terminal Block Panels

1. High Voltage Compartment
2. Bushing
3. Position Indicator
4. Low Voltage Compartment
5. Adjustable Legs

Vacuum Interrupter Detail

1. Fixed Contact
2. Washer
3. Terminal Post
4. Insulator
5. Arcing Chamber
6. Metal Bellows
7. Guide
8. Moving Contact
9. Terminal
10. Mechanical Coupling
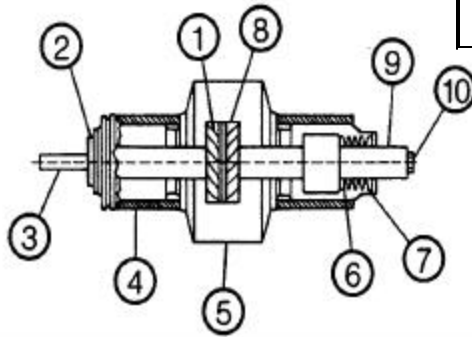
Figure 5-6: Type SDV Vacuum Circuit Breaker (Courtesy of Siemens)

SF$_6$ breakers are available in 15 kV to 242 kV ratings in single tanks and in 15 kV to 800 kV ratings in three (individual pole) tanks. Although SF$_6$ breakers are available in single-tank designs, the trend is toward three-tank. SF$_6$ breaker manufacturers have been able to reduce the size of the interrupting chambers, making the three-tank design more economical.

SF$_6$ circuit breakers are available with three operating mechanisms: pneumatic, hydraulic, and spring-operated. Some circuit breaker manufacturers have models for each of the operating mechanisms. Because of the differences between manufacturers and operating mechanisms, a discussion of maintenance and inspection procedures has been left up to the individual manufacturers. Although there are many differences, most circuit breakers require the bushings to be removed to expose the interrupting mechanism for inspection and maintenance.

Although there are a number of oil circuit breakers still in service, with the developments in SF$_6$ and vacuum technology, oil breakers are being phased out. Some companies sell oil breakers, but as used and reconditioned breakers.

5.3.3   Ratings

The rating of a circuit breaker is a summary of its characteristics that identifies its application on an electric system, its performance capabilities, and its adaptability. This summary of characteristics is given principally in terms of voltages, currents, and time as described in the rating tables, in the ANSI C37 Standards, and in the following subsections.

5.3.3.1   Voltage: Voltage characteristics are defined in terms of rms nominal, rms rated maximum, rated voltage range factor, and rated dielectric strength.

5.3.3.1.1   Nominal Voltage: Nominal voltage, also known as voltage class, is used to identify the general voltage class or electric system voltage on which a particular circuit breaker was intended for application.

5.3.3.1.2   Rated Maximum Voltage: Rated maximum voltage is the maximum voltage for which the circuit breaker is designed and is also the upper limit for operation on an electric system. It is based on ANSI Std. C84.1, "American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz)," and ANSI Std. C92.2, "Preferred Voltage Ratings for Alternating Current Electrical Systems and Equipment Operating at Voltages Above 230 Kilovolts Nominal." It is the prime operating voltage reference and relates the rated short-circuit interrupting current and short-circuit interrupting kA or energy handling capabilities.

5.3.3.1.3   Rated Voltage Range Factor: Rated voltage range factor, designated as "K," defines the lower limit of operating voltage at which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.

"K" is the ratio of rated maximum voltage to this lower limit of operating voltage. The rated maximum voltage either divided by K or multiplied by the reciprocal, 1/K will produce the lower limit of operating voltage. See Table 5-20 for 72.5 kV through 800 kV circuit breakers, where the voltage range factor is 1.0. This limits the maximum interrupting current capability at voltages lower than rated voltage to a value no greater than the interrupting current capability at rated maximum voltage.

Table 5-20: Preferred Ratings for Indoor Circuit Breakers with Voltage Range Factor K = 1.0.*
Ref. ANSI/IEEE Std. C37.06-1997, Table 1.
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Line No.	Rated Maximum Voltage (1) kV, rms	Rated Voltage Range Factor K	Rated Continuous Current Amperes, rms	Rated Short-Circuit and Short-Time Current kA, rms	Rated Transient Recovery Voltages (3)		Rated Interrupting Time (5) ms	Rated Permissible Tripping Delay Time Y sec	Rated Closing and Latching Current (2) kA, peak
					Rated Peak Voltage E_2 kV, peak	Rated Time to Peak T_2 (4) μsec			
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
1	4.76	1.0	1200, 2000	31.5	8.9	50	83	2	82
2	4.76	1.0	1200, 2000	40	8.9	50	83	2	104
3	4.76	1.0	1200, 2000, 3000	50	8.9	50	83	2	130
4	8.25	1.0	1200, 2000, 3000	40	15.5	60	83	2	104
5	15	1.0	1200, 2000	20	28	75	83	2	52
6	15	1.0	1200, 2000	25	28	75	83	2	65
7	15	1.0	1200, 2000	31.5	28	75	83	2	82
8	15	1.0	1200, 2000, 3000	40	28	75	83	2	104
9	15	1.0	1200, 2000, 3000	50	28	75	83	2	130
10	27	1.0	1200	16	51	105	83	2	42
11	27	1.0	1200, 2000	25	51	105	83	2	65
12	38	1.0	1200	16	71	125	83	2	42
13	38	1.0	1200, 2000	25	71	125	83	2	65
14	38	1.0	1200, 2000, 3000	31.5	71	125	83	2	82
15	38	1.0	1200, 2000, 3000	40	71	125	83	2	104

*   For preferred capacitance current switching rating, see ANSI/IEEE C37.06-1997 Table 1A.
For preferred dielectric ratings, see Table 5-22.
For circuit breakers with a rated voltage range factor K greater than 1.0, see Tables 5-21 and ANSI/IEEE Std. C37.06-1997 A1A.
See notes following Table 5-21.

For 4.76 kV through 38.0 kV circuit breakers, Table 5-21 shows a rated maximum voltage related to an interrupting kA, rms rating. These circuit breakers all have a voltage range factor greater than 1.0, which permits operation at lower than rated voltage and a maximum interrupting current of K times rated interrupting current as described above.

5.3.3.1.4   Example (Table 5-21):

Circuit breaker rated 18 kA interrupting capacity, maximum operating voltage 15.0 kV, voltage range factor K = 1.30.

Calculate maximum interrupting current, I = (18)(1.3) = 23 kA.

Lower operating voltage limit, E = 15/1.3= 11.5 kV.

5.3.3.1.5   Rated Dielectric Strength: The rated dielectric strength of a circuit breaker is its voltage withstand capability with specified magnitudes and waveshapes of test voltage applied under specific test conditions. The schedule of dielectric tests for power circuit breakers includes values for low frequency and impulse. These values are fixed and are related directly to rated maximum voltage of breakers. Dielectric test values for outdoor ac high-voltage power circuit breakers are shown in Table 4 of ANSI Std. C37.06 (see Table 5-22).

5.3.3.2   **Current:** Current characteristics are defined as follows:

5.3.3.2.1   Rated Continuous Current: The rated continuous current of a circuit breaker is the designated limit of current in rms amperes at rated frequency that it is required to carry continuously without exceeding any of the limitations designated in ANSI Std. C37.06. (Refer to Tables 5-20, 5-21, 5-23 and 5-24.)

Table 5-21: Preferred Ratings for Indoor Circuit Breakers with Voltage Range Factor K >1.0*
Ref. ANSI/IEEE Std. C37.06-1997, Table A1.
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Rated Maximum Voltage (1) kV, rms	Rated Voltage Range Factor K (2)	Rated Continuous Current at 60 Hz (3) Amperes	Rated Short-Circuit Current Δ (at Rated Maximum kV) (4)(5)(6)(10) kA, rms	Transient Recovery Voltages (9)			Rated Interrupting Time (7)cycles	Rated Maximum Voltage Divided by K kV, rms	Maximum Symmetrical Interrupting Capability and Rated Short-Time Current (4)(5)(8) kA, rms	Closing and Latching Capability 2.7K times Rated Short-Circuit (4), kA, Crest
				Rated Time to Point P $T_2\beta$ μsec	Rated Rate R kV / μ sec	Rated Delay Time T_1 μ sec				
4.76	1.36	1200	8.8	--	--	--	5	3.5	12	32
4.76	1.24	1200, 2000	29	--	--	--	5	3.85	36	97
4.76	1.19	1200, 2000, 3000	41	--	--	--	5	4.0	49	132
8.25	1.25	1200, 2000	33	--	--	--	5	6.6	41	111
15.0	1.30	1200, 2000	18	--	--	--	5	11.5	23	62
15.0	1.30	1200, 2000	28	--	--	--	5	11.5	36	97
15.0	1.30	1200, 2000, 3000	37	--	--	--	5	11.5	48	130
38.0	1.65	1200, 2000, 3000	21	--	--	--	5	23.0	35	95
38.0	1.0	1200, 3000	40	--	--	--	5	38.0	40	108

* For rated dielectric test values, see Table 5-22.
Δ For the related required capabilities associated with the rated short-circuit current of the circuit breaker, see note 4.
β These rated values are not yet standardized. Work is in progress.

Notes for Tables 5-20 and 5-21
(Numbers in parentheses in the tables refer to the following correspondingly numbered notes)

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see ANSI/IEEE Std. 37.04-1979, ANSI/IEEE Std. C37.09-1979, and ANSI/IEEE Std. C37.100-1981.

The interrupting ratings are for 60-Hz systems. Applications on 25-Hz systems should receive special consideration.

Current values have been rounded off to the nearest kiloampere (kA) except that two significant figures are used for values below 10 kA.

(1) The voltage rating is based on ANSI C84.1-1982, where applicable, and is the maximum voltage for which the breaker is designed and the upper limit for operation.
(2) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.
(3) The 25-Hz continuous current ratings in amperes are given herewith following the respective 60-Hz rating: 600-700; 1200-1400; 2000-2250; 3000-3500.
(4) Related Required Capabilities. The following related required capabilities are associated with the short-circuit current rating of the circuit breaker.

  (a) Maximum symmetrical interrupting capability (kA, rms) of the circuit breaker is equal to K times rated short-circuit current.
  (b) 3-second short-time current carrying capability (kA, rms) of the circuit breaker is equal to K times rated short-circuit current.
  (c) Closing and latching capability (kA, rms) of the circuit breaker is equal to 1.6 K times rated short-circuit current. If expressed in peak amperes, the value is equal to 2.7 K times rated short-circuit current.
  (d) 3-second short-time current carrying capability and closing and latching capability are independent of operating voltage up to and including rated maximum voltage.

(5) To obtain the required symmetrical current interrupting capability of a circuit breaker at an operating voltage between 1/K times rated maximum voltage and rated maximum voltage, the following formula shall be used:

  Required symmetrical current interrupting capability = rated short-circuit current x $\dfrac{\text{(rated maximum voltage)}}{\text{(operating voltage)}}$

  For operating voltages below 1/K times rated maximum voltage, the required symmetrical current interrupting capability of the circuit breaker shall be equal to K times rated short-circuit current.

(6) With the limitation stated in 5.10 of ANSI/IEEE C37.04-1979, all values apply for polyphase and line-to-line faults. For single-phase-to-ground faults, the specific conditions stated in 5.10.2.3 of ANSI/IEEE C37.04-1979 apply.
(7) The ratings in this column are on a 60-Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specified conditions. The values may be exceeded under certain conditions as specified in 5.7 of ANSI/IEEE Std. C37.04-1979.
(8) Current values in this column are not to be exceeded even for operating voltages below 1/K times rated maximum voltage. For voltages between rated maximum voltage and 1/K rated maximum voltage, follow (5) above.
(9) The rated values for T_2 are not standardized for indoor oilless circuit breakers; however, $E_2 = 1.88$ times rated maximum voltage.
(10) Rated permissible tripping delay time (Y) = 2 seconds.

Table 5-22: Preferred Dielectric Withstand Ratings and External Insulation. Ref. ANSI/IEEE Std. C37.06-1997, Table 4.
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			Power Frequency		Impulse Test 1.2 x 50 μsec wave (a)			Switching Impulse		
						Chopped Wave kV Peak Minimum Time to Sparkover			Withstand Voltage Terminal to Terminal on	Minimum Creepage Distance of External
Line No.	Rated Maximum Voltage kV, rms	Rating Table No.	1 minute Dry kV, rms	10 seconds Wet kV, rms	Full Wave (2) Withstand kV, Peak	2 μsec Withstand	3 μsec Withstand	Withstand Voltage Terminal to Ground with Breaker Closed kV, Peak	One Phase with Circuit Breaker Open kV, Peak	Insulation to Ground, Inches
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
1	4.76	1	19	(3)	60	(3)	(3)	(3)	(3)	(3)
2	8.25	1	36	(3)	95	(3)	(3)	(3)	(3)	(3)
3	15.0	1	36	(3)	95	(3)	(3)	(3)	(3)	(3)
4	15.5	2	50	45	110	142	126	(3)	(3)	9 (0.23m)
5	25.8	2	60	50	150	194	172	(3)	(3)	15 (0.38m)
6	25.8 (4)	2	60	50	125	(3)	(3)	(3)	(3)	15 (0.38m)
7	27.0	1	60	(3)	125	(3)	(3)	(3)	(3)	(3)
8	38.0	1	80	(3)	150	(3)	(3)	(3)	(3)	(3)
9	38.0	2	80	75	200	258	230	(3)	(3)	22 (0.56m)
10	38.0 (4)	2	80	75	150	(3)	(3)	(3)	(3)	22 (0.56m)
11	48.3	2	105	95	250	322	288	(3)	(3)	28(0.71m)
12	72.5	2	160	140	350	452	402	(3)	(3)	42 (1.07m)
13	123	3	260	230	550	710	632	(3)	(3)	70 (1.78m)
14	145	3	310	275	650	838	748	(3)	(3)	84 (2.13m)
15	170	3	365	315	750	968	862	(3)	(3)	93 (2.49m)
16	245	3	425	350	900	1160	1040	(3)	(3)	140 (3.56m)
17	362	3	555	(3)	1300	1680	1500	825	900	209 (5.31m)
18	550	3	860	(3)	1800	2320	2070	1175	1300	318 (8.08m)
19	800	3	960	(3)	2050	2640	2360	1425	1500	442 (11.23m)

NOTES:
(1) For circuit breakers applied in gas-insulated substations, see ANSI/IEEE Std. C37.06-1997, Table 5.
(2) 1.2 x 50 μ seconds positive and negative wave as defined in IEEE Std. 4. All impulse values are phase-to-phase and phase-to-ground and across the open contact.
(3) Not required.
(4) These circuit breakers are intended for application on grounded-wye distribution circuits equipped with surge arresters.

Table 5-23: Preferred Ratings for Outdoor Circuit Breakers 72.5 kV and Below,
Including Circuit Breakers Applied in Gas-Insulated Substations.* Ref. ANSI/IEEE Std. C37.06-1997, Table 2.
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Line No.	Rated Maximum Voltage (1) kV, rms	Rated Voltage Range Factor K	Rated Continuous Current Amperes, rms	Rated Short-Circuit and Short-Time Current kA, rms	Rated Transient Recovery Voltages (3)		Rated Interrupting Time (5) ms	Rated Permissible Tripping Delay Time Y sec	Rated Closing and Latching Current (2) kA, peak
					Rated Peak Voltage E_2 kV, peak	Rated Time to Peak T_2 (4) μsec			
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
1	15.5	1.0	600, 1200	12.5	29	36	83	2	33
2	15.5	1.0	1200, 2000	20.0	29	36	83	2	52
3	15.5	1.0	1200, 2000	25.0	29	36	83	2	65
4	15.5	1.0	1200, 2000, 3000	40.0	29	36	83	2	104
5	25.8	1.0	1200, 2000	12.5	48.5	52	83	2	33
6	25.8	1.0	1200, 2000	25.0	48.5	52	83	2	65
7	38.0	1.0	1200, 2000	16.0	71	63	83	2	42
8	38.0	1.0	1200, 2000	20.0	71	63	83	2	52
9	38.0	1.0	1200, 2000	25.0	71	63	83	2	65
10	38.0	1.0	1200, 2000	31.5	71	63	83	2	82
11	38.0	1.0	1200, 2000, 3000	40.0	71	63	83	2	104
12	48.3	1.0	1200, 2000	20.0	91	80	83	2	52
13	48.3	1.0	1200, 2000	31.5	91	80	83	2	82
14	48.3	1.0	1200, 2000, 3000	40.0	91	80	83	2	104
15	72.5	1.0	1200, 2000	20.0	136	106	83	2	52
16	72.5	1.0	1200, 2000	31.5	136	106	83	2	82
17	72.5	1.0	1200, 2000, 3000	40.0	136	106	83	2	104

*   For rated dielectric test values, see Table 5-22 and ANSI/IEEE C37.06-1997 Table 5.
    See notes following Table 5-24.

Table 5-24: Preferred Ratings for Outdoor Circuit Breakers 121 kV and Above, Including Circuit Breakers
Applied in Gas-Insulated Substations.* Ref. ANSI/IEEE Std. C37.06-1997, Table 3.
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| Line No. | Rated Maximum Voltage (1) kV, rms | Rated Voltage Range Factor K | Rated Continuous Current Amperes, rms | Rated Short-Circuit and Short-Time Current kA, rms | Rated Transient Recovery Voltages (6) | | | Rated Interrupting Time (5) ms | Rated Permissible Tripping Delay Time Y sec | Rated Closing and Latching Current (2) kA, peak |
| | | | | | Rated Time to Peak T_2 (4) μsec | Rated Rate R kV/μsec | Rated Delay Time T_1 μsec | | | |
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
1	123	1.0	1200	20	275	1.7	2	50	1	52
2	123	1.0	1600, 2000, 3000	40	260	1.8	2	50	1	104
3	123	1.0	2000, 3000	63	260	1.8	2	50	1	164
4	145	1.0	1200	20	330	1.7	2	50	1	52
5	145	1.0	1600, 2000, 3000	40	310	1.8	2	50	1	104
6	145	1.0	2000, 3000	63	310	1.8	2	50	1	164
7	145	1.0	2000, 3000	80	310	1.8	2	50	1	208
8	170	1.0	1200	16	395	1.7	2	50	1	42
9	170	1.0	1600	31.5	360	1.8	2	50	1	82
10	170	1.0	2000	40	360	1.8	2	50	1	104
11	170	1.0	2000	50	360	1.8	2	50	1	130
12	170	1.0	2000	63	360	1.8	2	50	1	164
13	245	1.0	1600, 2000, 3000	31.5	520	1.8	2	50	1	82
14	245	1.0	2000, 3000	40	520	1.8	2	50	1	104
15	245	1.0	2000	50	520	1.8	2	50	1	130
16	245	1.0	2000, 3000	63	520	1.8	2	50	1	164
17	362	1.0	2000, 3000	40	775	1.8	2	33	1	104
18	362	1.0	2000	63	775	1.8	2	33	1	164
19	550	1.0	2000, 3000	40	1325	1.6	2	33	1	104
20	550	1.0	3000	63	1325	1.6	2	33	1	164
21	800	1.0	2000, 3000	40	1530	1.9	2	33	1	104
22	800	1.0	3000	63	1530	1.9	2	33	1	164

*   For preferred dielectric ratings, see Tables 5-22 and ANSI/IEEE C37.06-1997 Table 5.
     See following notes.

Notes for Tables 5-20, 5-23, and 5-24
(Numbers in parenthesis in the tables refer to the following correspondingly numbered notes)

For service conditions, definitions, interpretations of ratings, tests, and qualifying terms, see ANSI/IEEE Std. C37.04, ANSI Std. 37.06.01, ANSI/IEEE Std. C37.09, and ANSI/IEEE Std. C37.100.

The preferred ratings are for 60-Hz systems. Applications at other system frequencies should receive special considerations; see C37.010.

Current values have generally been rounded off to the nearest kiloampere (kA) except that two significant figures are used for values below 10 kA.

(1)   The voltage rating is based on ANSI C84.1, where applicable, and is the maximum voltage for which the breaker is designed and the upper limit for operation.
(2)   Rated closing and latching current (kA, peak) of the circuit breaker is 2.6 times the rated short-circuit current. (If expressed in terms of kA, rms total current, the equivalent value is 1.55 times rated short-circuit current.)
(3)   Tables 1 and 2 only. The rated transient recovery voltage envelope is the "one-minus-cosine" (1-cosine) shape. See Figure A1 in the appendix.
(4)   If the source of power to a circuit breaker is a single transformer or a bank of transformers and there are no substantial capacitors or loaded feeders connected to the source side of the circuit breaker, the transient recovery voltage may be more severe than those covered in these tables. T_2 values for these applications are being developed.
(5)   The ratings in this column are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and the interruption of the main circuit on the primary arcing contacts under certain specified conditions. The values may be exceeded under certain conditions as specified in ANSI/IEEE Std. C37.04, sub-clause covering "Rated Interrupting Time."
(6)   Table 3 only. The rated transient recovery voltage envelope is the "exponential-cosine" shape. See Figure A2 in the Appendix. E_2 = 1.76 times rated maximum voltage; E_1 = 1.5/2/3 times rated maximum voltage.

5.3.3.2.2   Altitude Correction Factors: For applications at altitudes higher than 3300 ft (1000 m), rated dielectric strength and rated maximum voltage shall be multiplied by an altitude correction factor for voltage, and current shall be multiplied by an altitude correction factor for current to obtain values at which applications may be made. See Table 5-25 for altitude correction factors.

Table 5-25: Altitude Correction Factors (ACF)
for Voltage and Current. Ref. ANSI/IEEE Std. C37.04-1979,
Table 1. Copyright © 1979. IEEE. All rights reserved.

| Altitude | | ACF for | ACF for |
(ft)	(m)	Voltage *#	Continuous Current*
3300	1000	1.00	1.00
5000	1500	0.95	0.99
10000	3000	0.80	0.96

*   Interpolated values shall be used in determining correction factors for intermediate altitudes.
\#   For some types of circuit breakers (for example, those with sealed interrupters), it may not be necessary to apply the ACF for voltages to rated maximum voltage. The manufacturer should be consulted.

5.3.3.2.3 Rated Short-Circuit Current: The rated short-circuit current of a circuit breaker is the highest value of the symmetrical component of the polyphase or line-to-line short-circuit current in rms amperes measured from the envelope of the current wave at the instant of primary arcing contact separation that the circuit breaker is required to interrupt at rated maximum voltage and on the standard operating duty. It also establishes, by fixed ratios as defined in ANSI/IEEE Std. C37.04-5.10.2, the highest currents that the breaker is required to close and latch against, to carry, and to interrupt.

The relationship of rated short-circuit current to the other required capabilities is illustrated in Figures 5-7 and 5-8.

CLOSING AND LATCHING CAPABILITY

MAXIMUM SYMMETRICAL INTERRUPTING CAPABILITY AND CARRYING CAPABILITY FOR THE NUMBER OF SECONDS SPECIFIED IN 5. 10.2.5 AND 5.8

RATED SHORT-CIRCUIT

CURRENT x $\dfrac{\text{RATED MAX VOLTAGE}}{\text{OPERATING VOLTAGE}}$

SYMMETRICAL INTERRUPTING CAPABILITY

1.6K RATED SHORT-CIRCUIT CURRENT*

K RATED SHORT-CIRCUIT CURRENT

RATED SC CURRENT

RMS CURRENT

OPERATING VOLTAGE

1/K RATED MAX VOLTAGE

NOMINAL SYSTEM VOLTAGE

RATED MAXIMUM VOLTAGE

* OR 2.7K TIMES RATED SHORT-CIRCUIT CURRENT IF CURRENT IS MEASURED IN PEAK AMPERES.
NOTE: K EQUALS VOLTAGE RANGE FACTOR. (FOR PREFERRED STANDARD VALUES SEE ANSI C37.06)

Figure 5-7: Relation of Symmetrical Interrupting Capability, Closing Capability,
Latching Capability, and Carrying Capability to Rated Short-Circuit Current.
Ref. ANSI/IEEE Std. C37.04-1979, Fig. 1. Copyright © 1979. IEEE. All rights reserved.

ASYMMETRICAL INTERRUPTING CAPABILITY=S × SYMMETRICAL INTERRUPTING CAPABILITY, BOTH AT SPECIFIED OPERATING VOLTAGE

SYMMETRICAL INTERRUPTING CAPABILITY AT SPECIFIED OPERATING VOLTAGE=1.0

CIRCUIT BREAKER CONTACT PARTING TIME
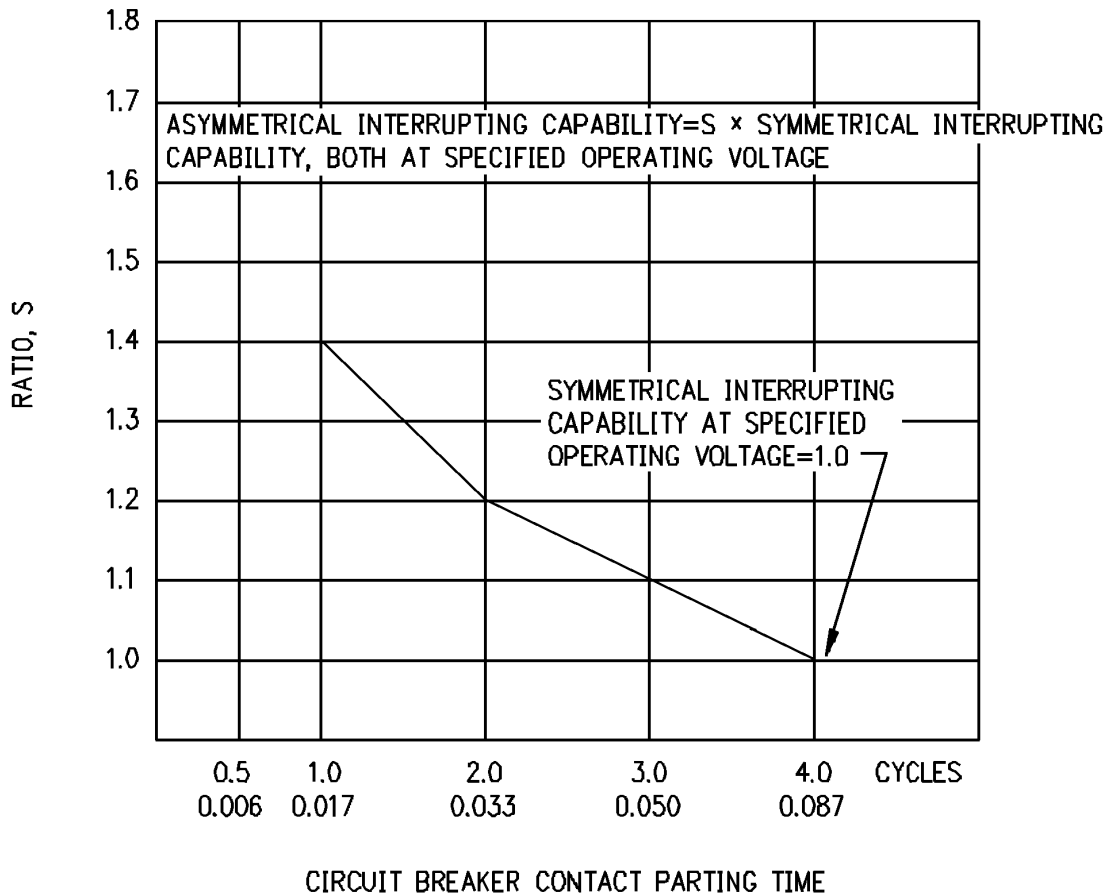
SUM OF 1/2 CYCLE TRIPPING DELAY PLUS THE OPENING TIME OF THE INDIVIDUAL BREAKER (REFER TO 5. 10.2.2.2)

NOTE: FOR RELATION OF SYMMETRICAL INTERRUPTING CAPABILITY AT SPECIFIED OPERATING VOLTAGE TO RATED SHORT–CIRCUIT CURRENT, SEE FIGURE 1.

Figure 5-8: Ratio of Circuit Breaker Asymmetrical to Symmetrical Interrupting Capabilities. Ref. ANSI/IEEE Std. C37.04-1979, Fig. 2. Copyright © 1979. IEEE. All rights reserved.

5.3.3.2.4 Related Required Capabilities: In addition to the current ratings defined above, symmetrically rated circuit breakers have related current capabilities. These related capabilities, discussed in detail in ANSI/IEEE Std. C37.04, are essentially as follows:

5.3.3.2.4.1 Maximum Symmetrical Interrupting Capability: Maximum symmetrical interrupting capability is K times rated short circuit.

5.3.3.2.4.2   Current: These related required capabilities are based on a relay time of one-half cycle, but may be used with any permissible tripping delay.

5.3.3.2.4.3   Required Symmetrical Interrupting Capability: Required symmetrical interrupting capability of a circuit breaker for polyphase and line-to-line faults is the highest value of the symmetrical component of the short-circuit current in rms amperes at the instant of primary arcing contact separation that the circuit breaker shall be required to interrupt at a specified operating voltage on the standard operating duty and irrespective of the direct current component of the total short-circuit current. The numerical value at an operating voltage between 1/K times rated maximum voltage and rated maximum voltage shall be determined using Equation 5-3:

Equation 5-3

$$\text{Required Symmetrical Interrupting Capability} = \text{Rated Short-Circuit Current} \times \left(\frac{\text{Rated Maximum Voltage}}{\text{Operating Voltage}} \right)$$

In no case shall the required symmetrical interrupting capability exceed K times rated short-circuit current.

5.3.3.2.4.4   Required Asymmetrical Interrupting Capability: Required asymmetrical interrupting capability of a circuit breaker for polyphase and line-to-line faults is the highest value of the total short-circuit current in rms amperes at the instant of primary arcing contact separation that the breaker shall be required to interrupt at a specified operating voltage and on the standard operating duty.

The numerical value shall be equal to the product of a ratio S, specified below and illustrated in Figure 5-7, times the required symmetrical interrupting capability of the breaker determined for the operating voltage. The values of S shall be 1.4, 1.3, 1.2, 1.1, or 1.0 for breakers having primary arcing contact parting times of 1, 1.5, 2, 3, 4, or more cycles, respectively. The values of S for primary arcing contact parting times between those given above shall be determined by linear interpolation. The primary arcing contact parting time shall be considered equal to the sum of one-half cycle (present practical minimum tripping delay) plus the lesser of the actual opening time of the particular breaker, or 1.0, 1.5, 2.5, or 3.5 cycles for breakers having a rated interrupting time of 2, 3, 5, or 8 cycles, respectively.

5.3.3.2.4.5   Required Symmetrical and Asymmetrical Interrupting Capability: Required symmetrical and asymmetrical interrupting capability of a circuit breaker for single line-to-ground faults shall be 1.15 times the corresponding values specified for polyphase and line-to-line faults. In no case are the capabilities for single line-to-ground faults required to exceed K times the symmetrical interrupting capability (that is, K times rated short-circuit current) and K times the asymmetrical interrupting capability, respectively, determined at rated maximum voltage.

5.3.3.2.4.6   Three-Second Short-Time Capability: Three-second short-time capability = K times rated short-circuit current.

5.3.3.2.4.7   Closing and Latching Capability: Closing and latching capability 1.6 K times rated short-circuit capability.

5.3.3.3   **Interrupting Time**: The rated interrupting time of a circuit breaker is the maximum permissible interval between the energizing of the trip circuit at rated control voltage and the interruption of the main circuit in all poles on an opening operation, when interrupting a current within its interrupting

capabilities. At duties below 25 percent of the asymmetrical interrupting capability at rated maximum voltage, the circuit has to be interrupted, but the time required for interruption may be greater than the rated interrupting time by as much as 50 percent for 5- and 8-cycle breakers and 1 cycle for 3-cycle breakers. For breakers equipped with resistors, the interrupting time of the resistor current may be longer. The interrupting time for a close–open operation at a specified duty should not exceed the rated interrupting time by more than 1 cycle for 5- and 8-cycle breakers and one-half cycle for 3-cycle breakers. When time is expressed in cycles, it should be on a 60-hertz basis.

5.3.3.4   Rated Permissible Tripping Delay: The rated permissible tripping delay of a circuit breaker is Y seconds and is the maximum value of time for which the circuit breaker is required to carry K times rated short-circuit current after closing on this current and before interrupting. For values, see ANSI Std. C37.06.

5.3.3.5   Other Factors Affecting Rating: The factors noted above form the basis of rating breakers complying with ANSI/IEEE Std. C37.04. Other factors that may affect breaker capability include duty cycle, transient recovery voltage, reactive component of load, etc. These are discussed in detail in ANSI/ IEEE Std. C37.04.

In particular, the duty cycle of the circuit breaker has to be considered in its application. The duty is the short-circuit current required to be interrupted, closed upon, etc. The cycle is a predetermined sequence of closing and opening operations.

The standard duty cycle to which circuit breaker ratings are related is one closing plus one opening operation, followed by a 15-second waiting period, followed by a second closing and a second opening operation (CO + 15 Sec + CO). This duty cycle permits application of the circuit breaker at 100 percent of its rating. Numerous other operating cycles and time intervals can be used. If the number of operating cycles is greater and/or the time intervals are shorter than the standard duty cycle, derating of the breaker interrupting capability is necessary according to the principles and procedures given in ANSI/IEEE Std. C37.04.

5.3.4   Operating Mechanisms

The operating mechanism of a circuit breaker has to be designed to ensure positive or definite opening of the circuit breaker, and circuit interruption has to occur whether the tripping or opening signal is received with the circuit breaker fully closed or in any partially closed position. The operating mechanism should also be capable of closing, reclosing and latching closed the circuit breaker when applied to the short-circuit current shown in the rating tables (See Tables 5-20, 5-23, and 5-24).

Operating mechanisms can be provided with or for multiple-pole or independent-pole operation. The term "operation" is intended to cover tripping (opening), closing, and reclosing of the circuit breaker. Most circuit breakers in the United States utilize multiple-pole (three-pole) operation to serve and protect their entire service area by simultaneous opening or closing of their three poles (phases).

Operating mechanisms are designed to have the closing function in a ready-to-close condition upon application of a closing signal. Simultaneous with the closing, the tripping function is placed in a ready-to-trip condition by electrical, mechanical, or both electrical and mechanical facilities in the operating mechanism. At the end of the previous closing operation, the closing function is again placed in a ready-to-close condition. This interaction of closing and tripping facilities permits any planned number of sequential closing and tripping actions to be performed.

The operating mechanism has to perform one complete closing operation including automatic cutoff of the closing power circuit after the initiating control device has been operated either manually or automatically and the first seal-in device in the control scheme has responded, even though the contacts of the initiating control device might be opened before the closing operation has been completed. Furthermore, a closing operation should not be performed at a control voltage lower than the minimum control voltage at which successful tripping can be performed. Most circuit breakers use shunt (voltage) trip coils that have to be capable of tripping the circuit breaker when any voltage in the control voltage range is applied, even if the trip coil plunger is away from its normal maximum force position to the extent that it is in contact with the actuating trigger of the tripping system.

Other tripping solenoids include those operated by current from bushing or separate current transformers and those operated by a capacitor trip device discharge into the trip coil. Refer to Table 5-26 for ac and dc control, tripping and closing voltages, and voltage ranges.

The operating mechanism should incorporate a number of features specifically for maintenance and assembly operations. The mechanism has to have provisions that safeguard maintenance personnel from unintended operation. This is usually accomplished via fuse pullouts, permissive switches, or locking pins. Provisions are required for slowly closing the breaker to align the moving contacts. This is usually accomplished with a separate jacking device purchased with the breaker.

Operating mechanisms should be equipped with operation counters. Compressors should be equipped with elapsed running time meters. These two features are important to an effective maintenance program.

5.3.4.1   Solenoid Operating Mechanisms

5.3.4.1.1   Voltage (AC and DC)-Operated Solenoids: Voltage (ac and dc)-operated solenoids were used almost entirely on all circuit breakers in the past. They were effective but relatively slow compared to present operating methods. They also required a large-capacity power supply (transformer or battery) because of their heavy current (ampere) demand, particularly on large, high-voltage circuit breakers. Solenoids are still used on some smaller circuit breakers where their lower operating power requirements are within available limits. Capacitor trip devices can also be provided to operate the solenoid.

5.3.4.1.2   Current-Operated Solenoids: Current-operated solenoids supplied with current from bushing-type or separate current transformers are available on the smaller circuit breakers and, like the capacitor trip devices, they are very useful in isolated areas where a separate operating power supply cannot be justified.

5.3.4.1.3   Other Types: All other types of operating mechanisms (except manual) described below use small control solenoids of ac or dc operation to initiate the major closing operation performed by the pneumatic, hydraulic, or spring mechanisms.

5.3.4.2   Motor Operating Mechanisms: Motor operation of circuit breakers, like solenoids, was used mostly in the past on small circuit breakers and is still available from some suppliers. The motors can be ac or dc, usually of a high torque and high speed to drive a spring-loaded toggle over dead center and release to provide good closing speed.

5.3.4.3   Pneumohydraulic : Pneumohydraulic is a coined name for a combination of pneumatic and hydraulic operating mechanism. An air compressor provides high-pressure air (up to several thousand

Table 5-26: Rated Control Voltages and Their Ranges for Circuit Breakers. Ref. ANSI/IEEE Std. C37.06-
1997, Table 8. Reproduced with permission of the National Electrical Manufacturers Association.

Operating mechanisms are designed for the rated control voltages listed with operational capability throughout the
indicated voltage ranges to accommodate variations in source regulation, coupled with low charge levels, as well as
high charge levels maintained with floating charges. The maximum voltage is measured at the point of user
connection to the circuit breaker [see notes (12) and (13)] with no operating current flowing, and the minimum voltage
is measured with maximum operating current flowing.

Line No.	(11) Rated Control Voltage	Direct Current Voltage Ranges (1)(2)(3)(5) Volts, dc (8)(9)			Rated Control Voltage (60 Hz)	Alternating Current Voltage Ranges (1)(2)(3)(4)(8) Closing, Tripping, and Auxiliary Functions
		Closing and Auxiliary Functions		Opening Functions All Types		
		Indoor Circuit Breakers	Outdoor Circuit Breakers		Single-Phase	Single-Phase
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
1	24 (6)	--	--	14-28	120	104-127 (7)
2	48 (6)	38-56	36-56	28-56	240	208-254 (7)
3	125	100-140	90-140	70-140		
4	250	200-280	180-280	140-280	Polyphase	Polyphase
5					208Y/120	180Y/104-
6						220Y/127
7					240	208-254

* Note (10) applies to the entire table.
  See following notes.

Notes for Table 5-26

(1)   Electrically operated motors, contactors, solenoids, valves, and the like need not carry a nameplate voltage
        rating that corresponds to the control voltage rating shown in the table as long as these components perform
        the intended duty cycle (usually intermittent) in the voltage range specified.
(2)   Relays, motors, or other auxiliary equipment that functions as a part of the control for a device shall be
        subject to the voltage limits imposed by this standard, whether mounted at the device or at a remote
        location.
(3)   Circuit breaker devices, in some applications, may be exposed to control voltages exceeding those specified
        here due to abnormal conditions such as abrupt changes in line loading. Such applications required specific
        study, and the manufacturer should be consulted. Also, application of switchgear devices containing solid-
        state control, exposed continuously to control voltages approaching the upper limits of ranges specified
        herein, require specific attention and the manufacturer should be consulted before application is made.
(4)   Includes supply for pump or compressor motors. Note that rated voltages for motors and their operating
        ranges are covered in ANSI/NEMA MG-1.
(5)   It is recommended that the coils of closing, and auxiliary, and tripping devices that are connected continually
        to one dc potential should be connected to the negative control bus so as to minimize electrolytic
        deterioration.
(6)   24-volt or 48-volt tripping, closing, and auxiliary functions are recommended only when the device is located
        near the battery or where special effort is made to ensure the adequacy of conductors between battery and
        control terminals. 24-volt closing is not recommended.
(7)   Includes heater circuits.
(8)   Voltage ranges apply to all closing and auxiliary devices when cold. Breakers utilizing standard auxiliary
        relays for control functions may not comply at lower extremes of voltage ranges when relay coils are hot, as
        after repeated or continuous operation.
(9)   Direct current control voltage sources, such as those derived from rectified alternating current, may contain
        sufficient inherent ripple to modify the operation of control devices to the extent that they may not function
        over the entire specified voltage ranges.
(10)   This table also applies for circuit breakers in gas-insulated substation installations.
(11)   In cases where other operational ratings are a function of the specific control voltage applied, tests in
        C37.09 may refer to the "Rated Control Voltage." In these cases, tests shall be performed at the levels in
        this column.

(12)   For an outdoor circuit breaker, the point of user connection to the circuit breaker is the secondary terminal block point at which the wires from the circuit breaker operating mechanism components are connected to the user's control circuit wiring.

(13)   For an indoor circuit breaker, the point of user connection to the circuit breaker is either the secondary disconnecting contact (where the control power is connected from the stationary housing to the removable circuit breaker), or the terminal block in the housing nearest to the secondary disconnection contact.

psi) to a cylinder with a piston used to drive hydraulic fluid into a piping system and servomechanism to provide closing and tripping operations when the appropriate control signals are applied.

The pneumohydraulic system is an energy storage system, integral with the circuit breaker, and is required to be of sufficient size to permit at least five complete closing–opening operations at rated short-circuit current, starting at normal working pressure and without replenishment of the compressed air energy store. It provides very high speed closing and tripping.

This type of mechanism is normally available, from certain suppliers, on 121 kV and higher rated circuit breakers.

5.3.4.4   Pneumatic: Pneumatic operating mechanisms utilize compressed high-pressure air (or other gas) to apply closing and tripping forces directly to the mechanism. A variation of pneumatic operation is pneumatic closing with a tripping spring being compressed during the pneumatic closing operation. The pressure varies widely among suppliers from a few hundred to several thousand psi.

Where the pneumatic energy storage is integral with the circuit breakers it has to be of sufficient size to permit at least two complete closing–opening operations at rated short-circuit current starting at normal working pressure and without replenishing the compressed air energy store.

Where the pneumatic energy storage is separate from the circuit breaker, it can be designed to any desired size for any desired combination of operations within the rating structure of the circuit breaker. It can also be utilized to operate (closing and tripping) several circuit breakers in a similar manner. It has almost unlimited flexibility for maintenance and emergency piping, valving, backup compressors, nitrogen bottles, temporary high-pressure hosing, etc.

This type of mechanism is available on most circuit breakers rated 23 kV and higher of the bulk air-blast and closed-cycle gas-blast types.

5.3.4.5   Motor-Charged Spring: Motor-charged spring operating mechanisms utilize a motor to compress a coil spring that holds this stored energy until a closing signal is received. Then the spring expands to close the circuit breaker and simultaneously to charge or compress a smaller coil spring, which is used to trip the circuit breaker. This trip spring may or may not be concentric with the closing spring, depending on the individual design. The energy storage capability of a motor-compressed spring operating mechanism has to be sufficient for an opening–closing–opening operation at rated short-circuit current, after which the spring-compressing motor should not require more than 10 seconds to compress the closing spring. Longer times are permissible through agreement between the purchaser and the manufacturer. In cases where the desired reclosing scheme depends on motor operation, a dc motor may be specified and supplied from a battery or rectifier.

The above-described breaker mechanism provides high-speed closing and tripping. This type of mechanism is available on 2.4 kV through 72.5 kV circuit breakers.

5.3.4.6   Manual-Charged Spring: Manual-charged spring operating mechanisms have very limited application. They are available only from a few suppliers. Applications where reclosing operation is not required would be suitable for this type of operating mechanism. Compression of the spring to store the closing energy is accomplished by a hand jack that may be portable or integral with the operating mechanism. Energy storage required consists of only one closing and one tripping operation.

5.3.4.7   Manual Operating Mechanisms: Manual operating mechanisms are only available on small circuit breakers. They utilize a lever-operated toggle mechanism that releases energy from a relatively small spring. They may or may not have tripping capability. If they cannot trip, a backup protective device should be applied.

5.3.5   Tests

Tests performed on circuit breakers can generally be classified as follows:

1. Design tests
2. Production tests
3. Tests after delivery
4. Field tests
5. Conformance tests

These tests are fully described in ANSI/IEEE Std. C37.09, "American Standard Test Procedure for AC High Voltage Circuit Breakers." While a detailed discussion of these tests is beyond the scope of this bulletin, a general outline of the tests involved follows.

5.3.5.1   Design Tests: Design tests consist of the following types of tests:

1. Maximum Voltage
2. Voltage Range Factor
3. Continuous Current-Carrying Rated Frequency Tests
4. Dielectric Strength Tests
5. Short-Circuit Tests
    a. Symmetrical interrupting capability (polyphase and line-to-line)
    b. Assymetrical interrupting capability (polyphase and line-to-line)
    c. Interrupting capability for single line-to-ground fault
    d. Closing, latching, carrying, and interrupting capability
    e. Short-time current carrying capability
    f. Reclosing capability
6. Transient Recovery Voltage
7. Standard Operating Duty
8. Tripping Delay
9. Interrupting Time
10. Reclosing Time
11. Load Current Switching Capability
    a. Low frequency withstand, dry and wet
    b. Full wave impulse withstand
    c. Impulse voltage test for interrupters and resistors
    d. Chopped wave impulse withstand
    e. Switching-impulse voltage withstand
12. Capacitor Switching

13. Rated Line Closing Switching Surge Factor
14. Out-of-Phase Switching Current
15. Shunt Reactor Switching
16. Excitation Current Switching
17. Mechanical Life
18. Control Voltage Current (Nominal Control Voltage)

5.3.5.2   Production Tests: Production tests are normally made by the manufacturer at the factory as part of the process of producing the circuit breaker. If the breaker is completely assembled prior to shipment, some of the production tests are made after final assembly, but other tests can often be made more effectively on components and subassemblies during or after manufacture.

If the circuit breaker is not completely assembled at the factory prior to shipment, appropriate tests on components should be made to check the quality of workmanship and uniformity of material used and to ensure satisfactory performance when properly assembled at its destination. This performance may be verified by performing tests after delivery.

Production tests and checks include the following:

1.   Current and Linear Coupler Transformer Tests
2.   Bushing Tests
3.   Gas Container Tests (ASME Certification)
4.   Pressure Tests
5.   Nameplate Check
6.   Leakage Tests
7.   Resistor, Heater, and Coil Check Tests
8.   Control and Secondary Wiring Check Tests
9.   Clearance and Mechanical Adjustment Check Tests
10. Mechanical Operation Tests
11. Timing Tests
12. Stored Energy System Tests
13. Conductivity of Current Path Test
14. Low-Frequency Withstand Voltage Tests on Major Insulation Components
15. Low-Frequency Withstand Voltage Tests on Control and Secondary Wiring

5.3.5.3   Tests After Delivery: Tests made by the purchaser after delivery of the circuit breaker to supplement inspection in determining whether the breaker has arrived in good condition may consist of timing tests on closing, opening, and close–open, no-load operations, and low-frequency voltage withstand tests at 75 percent of the rated low-frequency withstand voltage. Polarity and ratio tests on the current transformers are also recommended.

5.3.5.4   Field Tests: Field tests are made on operating systems usually to investigate the performance of circuit breakers under conditions that cannot be duplicated in the factory. They usually supplement factory tests and, therefore, may not provide a complete investigation of the breakers' capabilities. Emphasis is usually placed on performance under the particular conditions for which the tests are made rather than on a broad investigation, and the schedule and instrumentation are adapted accordingly.

Field tests may include transient recovery voltage performance, closing together two energized parts of a system operating at different levels of voltage and power factor, switching of full-sized shunt reactors or capacitor banks, contact timing for mechanically linked breaker poles or air supply linked poles where air

lines may differ in length, measurement of resistances and voltage sharing or division of opening and pre-insertion resistors, etc.

5.3.5.5   Conformance Tests: Conformance tests are those tests specifically made to demonstrate the conformance of a circuit breaker with ANSI Standards.

5.3.6   Control and Auxiliary Power Requirements

Rated control voltages for power circuit breakers in accordance with existing ANSI Std. C37.06 are shown in Table 5-26.

In addition to the above, it will be necessary to provide auxiliary power at the breaker for use in conjunction with heater elements, compressor motors, compartment lights, etc. Auxiliary power supplies are generally available in one of the forms shown in Table 5-26.

5.3.7   Purchase Evaluation

When evaluating different types of breaker construction for a specific substation, it is important to include the cost of necessary auxiliary equipment such as maintenance jacks, gas handling equipment, oil handling equipment, tank lifters, etc. Environmental considerations of esthetics, noise, and oil spills may also affect the choice of breaker type. Others considerations may include size and weight of the breaker, operating mechanism, lead time, and terms and conditions of the sale.

5.3.8   Shipment and Installation

5.3.8.1   Shipment: Immediately upon receipt, breakers should be examined for any damage en route. If damage is evident or indication of rough handling is visible, notify the carrier (transportation company) and the manufacturer promptly.

Method of shipment will be dictated by many things including size of the breaker, destination, urgency of delivery, etc. In general, the small- to medium (138 to 230 kV)-size oil breakers will be shipped fully assembled. Most breakers can be shipped either by rail or by truck.

5.3.8.2   Assembly and Installation: Detailed discussion of assembly and installation of circuit breakers is beyond the scope of this bulletin. However, additional comments can be found in NEMA Std. SG4, Part 6, "Instructions for the Installation, Operation and Care of Alternating-Current High-Voltage Circuit Breakers." Manufacturers' instructions are to be relied upon for the complete and proper installation of the equipment.

5.3.9   References

ANSI Std. C37.06, "Preferred Ratings and Related Required Capabilities of AC High-Voltage Circuit
        Breakers Rated on a Symmetrical Current Basis."

ANSI Std. C37.12, "American National Standard Guide Specifications for AC High-Voltage Circuit
        Breakers Rated on a Symmetrical Current Basis and a Total Current Basis."

ANSI Std. C84.1, "American National Standard Voltage Ratings for Electrical Power Systems and
        Equipment (60 Hz)."

ANSI Std. C92.2, "Preferred Voltage Ratings for Alternating Current Electrical Systems and Equipment Operating at Voltages Above 230 Kilovolts Nominal."

ANSI/IEEE Std. C37.04, "Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI/IEEE Std. C37.09, "American Standard Test Procedure for AC High Voltage Circuit Breakers."

ANSI/IEEE Std. 37.010, "Standard Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI/IEEE Std. 37.100, "Standard Definitions for Power Switchgear."

IEEE 1997 Summer Power Meeting, "Loading of Substation Electrical Equipment with Emphasis on Thermal Capability."
– Part I – Principles by B.J. Conway, D.W. McMullen, A.J. Peat, and J.M. Scofield of Southern California Edison Company.
– Part II – Application by I.S. Benko, D.E. Cooper, D.O. Craghead, and P.Q. Nelson of Southern California Edison Company.

IEEE Tutorial Course Text No. 75CH0975-3-PWR, "Application of Power Circuit Breakers," 1975.

NEMA Std. SG4, Part 6, "Instruction for the Installation, Operation and Care of Alternating-Current High-Voltage Circuit Breakers."

5.4   METAL-CLAD SWITCHGEAR

5.4.1   <u>General</u>

This section deals primarily with metal-clad switchgear for use in distribution substations. Metal-clad switchgear is defined as a type of metal-enclosed power switchgear with a number of necessary characteristics. These characteristics are fully defined in IEEE Std. C37.20.2, "Standard for Metal-Clad and Station-Type Cubicle Switchgear," Section 2.1.9.3. Briefly, they are as follows:

1. The main switching or interrupting device is removable.
2. Major components of the primary circuit are enclosed and are separated by grounded metal barriers.
3. All live parts are enclosed within grounded metal compartments with automatic shutters to block off energized parts when devices are disconnected.
4. The primary bus is covered with insulating material throughout.
5. There are mechanical interlocks for safety and proper operation.
6. Secondary devices are essentially isolated from primary elements.
7. A door to a circuit interrupting device may serve as a control panel or for access to some secondary elements.

5.4.1.1   Function: Metal-clad switchgear serves the same system function as comparable elements in a conventional open bus-type substation. These elements may include main power switching or interrupting devices, disconnecting switches, buses, instrument and control power transformers, and control and auxiliary devices, as well as other devices.

Metal-clad switchgear is usually applied where appearance, land use, compactness, ease of installation, exiting low-voltage circuits, maintenance in foul weather, or safety require consideration. Its application has become more commonplace to house additional equipment including battery, chargers, low-voltage panels, compact microprocessor relaying, and supervisory control equipment as indicated in Figure 5-9. The outdoor single control house including the switchgear offers a more complete factory-wired and tested assembly. The advent of the "double-high" breaker configuration in the lower voltage and ampacity cases offers lower costs, yet requires specific layouts to avoid joint cubicle-forced maintenance outages. The cost difference between an open substation versus metal-clad switchgear depends on the final installed and operating costs, which will vary by application and site.

5.4.1.2 Applicable National Standards: The main standards governing metal-clad switchgear are IEEE Std. C37.20.2, "IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear," NEMA Std. SG-5, "Standards for Power Switchgear Assemblies," and Std. SG-6, "Standards for Power Switching Equipment." The indoor oilless circuit breakers (predominantly equipped with vacuum interrupters and higher voltage SF_6 gas interrupting media) are as applied with metal-clad switchgear and rated in accordance with ANSI Std. C37.06. Additional applicable standards are listed in Section 5.4.5.

5.4.2 Types

5.4.2.1 Configurations: Metal-clad switchgear is available for both indoor and outdoor installations. The basic switchgear is the same for both types of installations. For outdoor installations, a weatherproof enclosure is provided. Weatherproof enclosures are made in several arrangements:

- Single-cubicle lineup, without an enclosed aisle
- Single line with enclosed aisle
- Double lineup, with a common enclosed center aisle

Figure 5-10 is a typical outdoor single-aisle arrangement. Variations have been made to extend the housing on either side of the aisle to use for ancillary equipment and functions. Manufacturers have adopted trade names for the various arrangements. Shipping splits can be accommodated to allow standard transportation and also to ease field assembly.

Any decision as to choice of indoor or outdoor type of switchgear should include a cost analysis. Usually weatherproof enclosures will cost less than indoor units (including the cost of a prefabricated or similar type of building and the additional labor and ancillary costs). Other factors, of course, may influence the decision such as joint use of any building for other purposes.

Metal-clad switchgear sections or cubicles are made for every recognized type of switching scheme, including straight bus (radial circuits), network, sectionalized bus, main and transfer bus, breaker-and-a-half, ring bus, double bus–double breaker, etc. The level of reliable bus configuration depends on the number of bus sections, redundant feeders, transformer sources, and alternative external local and remote switching features. Sections are made or can be adapted for almost any conceivable arrangement of the equipment usually required in circuits for feeders, transformers, generators, motors, reactors, and capacitors. Entrance provisions can be adapted to accommodate overhead through-roof bushings with insulated cable or bare bus bar circuits and non-segregated metal enclosed bus duct. Underground entrances are either by insulated cable through conduit circuits or wireways. Sections are made to accommodate all sorts of auxiliary equipment such as current and potential transformers, station power transformers, fuses, switches, surge arresters, etc.
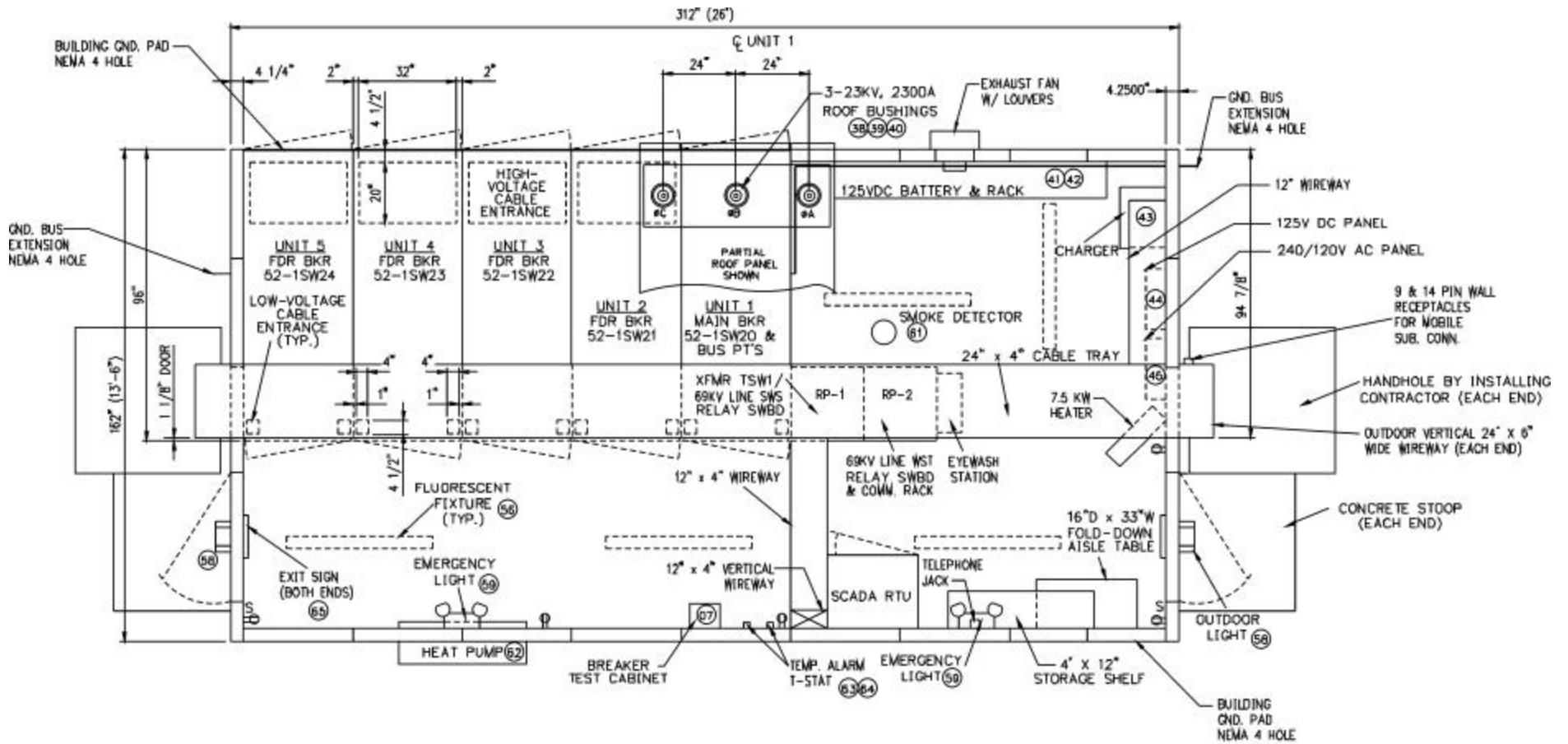
Figure 5-9: Single-Aisle Metal-Clad Switchgear with Ancillaries
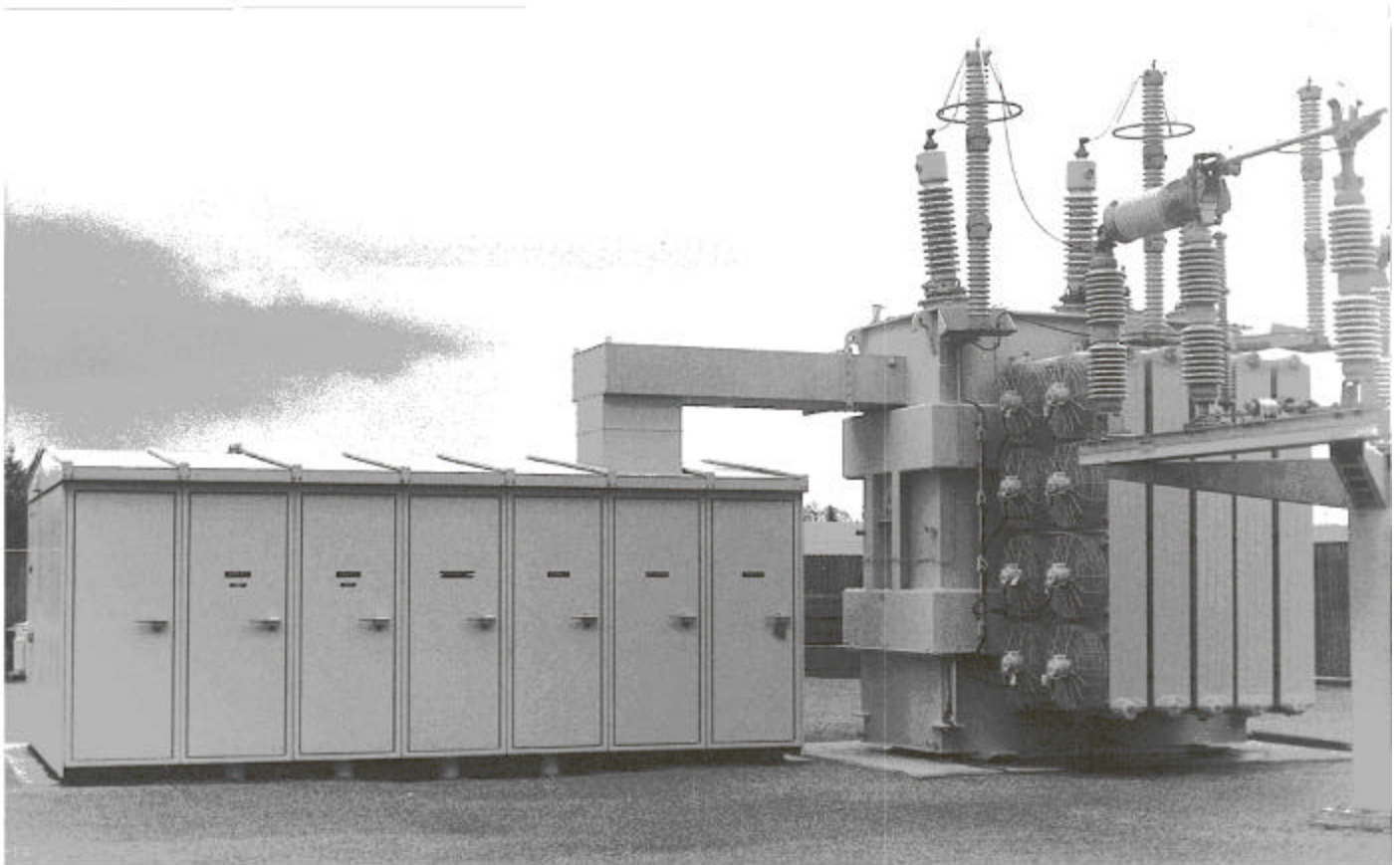
Figure 5-10: Typical Single-Aisle Switchgear Installation.
(Courtesy of Pederson Power Products)

5.4.2.2 Enclosure Categories: Switchgear assemblies are also installed in locations that vary as to the degree of access and exposure to the general public. The categories are intended to provide differing degrees of protection to personnel from coming in contact with the enclosed live parts.

5.4.2.1.1   Category A: This category provides a degree of protection for unauthorized personnel performing deliberate unauthorized acts on the switchgear lineup.

5.4.2.1.2   Category B: This category provides a degree of protection against contact with the live parts by untrained personnel and unauthorized personnel, not subject to the deliberate acts of unauthorized personnel.

5.4.2.1.3   Category C: This category provides a degree of protection against contact with the live parts of equipment located within secure areas by authorized personnel.

5.4.3   Ratings

5.4.3.1 Rated Nominal Voltage (rms): Rated nominal voltage of a switchgear assembly is the value assigned for identification. Standard ratings are 4.16, 7.2, 13.8, 25.0, and 34.5 kV. The 25 kV class circuits are served by either the more costly 34.5 kV class equipment or by some manufacturers' 25 kV class, which has now received ANSI Standards recognition.

5.4.3.2 Rated Maximum Voltage (rms): Rated maximum voltage is the highest rms voltage for which the equipment is designed and is the upper limit for operations. Standard ratings corresponding, respectively, to the values given in Section 5.4.3.1 above are 4.76, 8.25, 15.0, 27.0, and 38.0 kV. See IEEE Std. C37.20.2, Table 1.

5.4.3.3 Rated Frequency: Ratings for ac equipment are based on a frequency of 60 Hz.

5.4.3.4 Rated Insulation Levels: Rated insulation levels consist of two items: (1) 60 Hz, one-minute withstand voltage, and (2) impulse withstand voltage or BIL. The standard values are shown in Table 5-27:

Table 5-27: Rated Insulation Levels of Metal-Clad Switchgear

Rated Nominal Voltage (rms)	60 Hz, 1 Min Withstand	BIL
4.16 kV	19 kV	60 kV
7.2 kV	36 kV	95 kV
13.8 kV	36 kV	95 kV
25.0 kV	60 kV	125 kV
34.5 kV	80 kV	150 kV

See IEEE Std. C37.20.2, Table 1, for further clarification.

5.4.3.5 Rated Continuous Current: This is the maximum current in rms amperes at rated frequency that can be carried continuously by the primary circuit components, including buses and connections, without causing temperatures in excess of specified limits for any component. The standard ratings for the bus are 1200, 2000, and 3000 amperes.   The continuous current ratings of the individual units shall correspond to the ratings of the switching and interrupting devices used.

5.4.3.6 **Rated Short-Time or Momentary Current:** This is the maximum rms total current that can be carried momentarily without electrical, thermal, or mechanical damage. Standard ratings for a bus and its extensions should be matched to the breaker rated value, which can reach a maximum of 48 kA for 13.8 kV bus application.

5.4.3.7 **Interrupting or Switching Capability:** Interrupting or switching capability of a particular device such as a circuit breaker, interrupter switch, fuse, etc., used in a switchgear assembly is determined by the rated capabilities of that device as listed in the appropriate standards.

5.4.4 Purchase Considerations

5.4.4.1 **Procurement:** Metal-clad switchgear assemblies (breaker cells) for a particular job are normally purchased as a unit (including the breaker) from a single manufacturer because of the standardization and close coordination required among the various components such as interlocks and connections. The cells can be joined by either the switchgear breaker manufacturer or an OEM (original equipment manufacturer). Many qualified U.S. suppliers are widely available that can offer local assistance during and after installation.

5.4.4.2 **Specification:** Before undertaking a switchgear project, visit various installation sites and manufacturers' plants to observe applications and features that would suit the cooperative's needs. Specifications can be supplied by a consulting engineer or drafted based on use of the manufacturer's guideline specifications. Any specification for metal-clad switchgear should include the following information or requirements.

5.4.4.2.1 Switching Scheme Selection and One-Line Diagram: The most common configuration is a single bus with a main incoming breaker, a tie breaker, and at least four feeder breakers sized to carry 50 percent of normal load. The tie circuit allows supply from another transformer and external feeder cross ties to allow feeder and main breaker removal for maintenance. The choice should be made based on system operating and reliability requirements and, ultimately, cost. The one-line diagram (somewhat matching the physical arrangement desired) should indicate bus configuration, ratings, nomenclature, and ancillary equipment including auxiliary transformers, instrument transformers, surge arresters, number of conductors per circuit, and entry means.

5.4.4.2.2 Available Fault and Continuous Currents for Breaker Selection: Anything affecting the circuit breaker requirements should be mentioned such as ultimate source fault capability, parallel transformer operation and capacity, normal/emergency feeder loading, reclosing duty, operating voltage, capacitor or reactor switching, etc.

5.4.4.2.3 Main Bus Rating Selection: The predominant bus material used is copper, since it provides strength and connection advantages over aluminum bus. Standard ratings match the continuous current rating of available circuit breakers. Judicious arrangements of "source" and "load" breakers can result in the lowest bus current requirements. Future expansion should be considered. The bus support and conductor insulation system should be track resistant. The bus insulation should be void free by using either a heat-shrink polymer or fluidized bed-applied epoxy. Indicate the bus configuration, whether 3-wire (with neutral external to the switchgear) or 4-wire (including either reduced or full-size neutral). The neutral bus should not be confused with mandatory copper ground bus used to bond switchgear cubicles and housing to the station ground.

5.4.4.2.4 <u>Current and Potential Transformer Selection</u>: Each transformer should be located on the one-line diagram and its requirements described. The potential transformers are applied in a wye-wye connection with a resulting 120/208 V secondary connection that is used commonly for metering and relay potentials. Current transformers are usually single-ratio type with accuracy ranges from C200 to C400 (see Section 5.10.6) for most typical applications.

Carefully ground instrument transformer circuits. Separately ground VT primary and secondary circuits to avoid the tie between the primary and the secondary if the ground is lost. Ground CTs and VTs at one location on each circuit.

5.4.4.2.5 <u>Relay and Control Function Selection</u>: To ensure that the metal-clad switchgear is wired by the manufacturer as desired and sufficient space is provided for all equipment, it is vital to detail the types of relays, control schemes, interlocks, metering, and interconnection features to be incorporated. This usually involves a cubicle-by-cubicle list of materials to be furnished. It may also include schematic diagrams when requirements are complex.

5.4.4.2.6 <u>Closing, Tripping, and Power Requirements</u>: For circuit reliability, usually the switchgear is specified for dc control supply ranging from 48 to 125 volts dc. This control supply may be segmented by molded case breakers, fuse blocks, or fuse blocks with knife switches in several configurations at the cooperative's choice to provide close, open, and breaker motor-spring charging power. Auxiliary power may be furnished from a fused transformer within the switchgear lineup or externally from a feeder that is not affected by the switchgear outage. The two most popular auxiliary voltages are 240/120 volts ac, 3-wire, single-phase, or 120/208 volts ac, 4-wire, three-phase to supply lighting, transformer fan, and LTC control, battery charging, and switchgear environmental control. The station battery can be supplied with the switchgear to power the switchgear control supply as well as other station higher voltage breakers.

5.4.4.2.7 <u>Special Requirements of Temperature, Altitude, Unusual Atmospheric Contamination, Vibration, Etc.</u>: Standard conditions are for operation in air at nameplate ratings within –30°C and +40°C and at altitudes not exceeding 1000 meters (3300 feet). If a battery bank is housed within the switchgear, it is mandatory to supply enclosure environmental control by an air conditioner and resistance heating or a heat pump to keep the battery within its best operating range of from +10°C to +26°C. Airborne dust and other contaminants may require additional filters and special paint finishes. Address these site-specific conditions depending on operating experience with other electrical equipment. In most applications, it is necessary to provide either non-switched or thermostatically controlled long-life resistance heaters to prevent condensation on the bus insulation and within the breaker during daily and seasonal atmospheric changes.

5.4.4.2.8 <u>Physical Sketch of Desired Arrangement, Orientation, Mounting Requirements, Indoor or Outdoor Type, Etc.</u>: With a detailed and physically orientated one-line diagram, the manufacturer can usually submit acceptable arrangements that include cost savings not readily apparent to the cooperative. Plan, elevation, and cross-section sketches help the manufacturer interpret the specifications for any special arrangements and the inclusion of ancillaries.

5.4.4.2.9 <u>Itemized List of Requirements</u>: Clearly state in the Bill of Materials all requirements for equipment in each cubicle and include the number of spare breakers and test equipment to be provided, etc. State interface points at incoming bus connections, cable external connectors and insulating material, and enclosure grounding connectors.

5.4.5 References

ANSI Std. C37.06, "Preferred Ratings and Related Required Capabilities of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI/IEEE Std. C37.04, "Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

IEEE Std. C37.09, "Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

IEEE Std. C37.010, "Standard Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

IEEE Std. C37.2, "Standard Electrical Power System Device Function Numbers."

IEEE Std. C37.20.2, "Standard for Metal-Clad and Station-Type Cubicle Switchgear."

IEEE Std. C37.100, "Standard Definition for Power Switchgear."

NEMA Std. SG-2, "Standards for High-Voltage Fuses."

NEMA Std. SG-4, "Standards for Alternating Current High-Voltage Circuit Breakers."

NEMA Std. SG-5, "Standards for Power Switchgear Assemblies."

NEMA Std. SG-6, "Standards for Power Switching Equipment."

5.5 SUBSTATION VOLTAGE REGULATORS

5.5.1 General

Both three-phase and single-phase voltage regulators are used in distribution substations to regulate the load-side voltage. Substation regulators are one of the primary means, along with load-tap-changing power transformers, shunt capacitors, and distribution line regulators, for maintaining a proper level of voltage at a customer's service entrance.

A very important function of substation voltage regulation is to correct for supply voltage variation. With the proper use of the control settings and line drop compensation, regulators can correct for load variations as well. A properly applied and controlled voltage regulator not only keeps the voltage at a customer's service entrance within approved limits but also minimizes the range of voltage swing between light and heavy load periods.

The substation regulators may be located on individual feeders or in the transformer secondary circuit for main bus regulation. Normally, the low-voltage substation bus will be regulated rather than the individual feeders. Individual feeder regulation can usually be justified only when there are extreme variations between individual distribution feeder peak load times. Very long or heavily loaded distribution feeders may require supplemental regulators strategically located out on the line to maintain voltage levels within required limits.

In evaluating the proper application of voltage regulators, see RUS Bulletin 1724D-114, "Voltage Regulator Application on Rural Distribution Systems," and RUS Bulletin 1724D-112, "The Application of Shunt Capacitors to the Rural Electric System."

The voltage levels recommended by RUS are given in Bulletin 169-4, "Voltage Levels on Rural Distribution Systems." The recommended levels are based on ANSI Std. C84.1, "Voltage Ratings for Electric Power Systems and Equipment (60 Hz)."

Regulators for use on cooperatives' systems have to meet the requirements in RUS Bulletin 50-90 (S-2), "Specification for Substation Regulators," where applicable. These specifications apply to step-type single- or three-phase, substation or pole-mounted, outdoor, oil-immersed, self-cooled regulators.

In addition to RUS Bulletin 50-90 (S-2), all regulators should also comply with ANSI Std. C57.15, "Requirements, Terminology, and Test Code for Step-Voltage and Induction-Voltage Regulators," and ANSI Std. C57.95, "Guide for Loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators."

5.5.2 <u>Types</u>

There are two general types of voltage regulators, the induction regulator and the step-type regulator. Both types are available in single- or three-phase designs. The step-type regulator has by far the wider application in the electric distribution system. The step-voltage regulator has virtually replaced the induction-voltage regulator because it is lower in cost and equally reliable.

5.5.2.1 Step-Type Voltage Regulator: A step-voltage regulator is a regulator having one or more windings excited from the system circuit or a separate source and one or more windings connected in series with the system circuit for adjusting the voltage, or the phase relation, or both, in steps, without interrupting the load. A step-type voltage regulator consists of an autotransformer and a load-tap-changing mechanism built into an integral unit.

As with the induction regulator, when a voltage is impressed on the primary winding, the magnetic flux linking the secondary or series winding will induce a voltage in the series winding.

An automatic reversing switch is incorporated to obtain an additive or subtractive voltage from the series winding with respect to the primary voltage. Taps of the series winding are connected to an automatic tap-changing mechanism to regulate the amount of voltage change in equal steps.

The terminal designations of step-type voltage regulators are as follows:

- The terminal connected to the load is designated L.
- The terminal connected to the source is designated S.
- The common terminal is designated SL.

For three-phase regulators, these identifications are Sl, S2, S3, Ll, L2, L3, and S_OL_O. This is illustrated in Figure 3 of RUS Bulletin 1724D-114 and is also found in ANSI C57.15.

5.5.2.2 Single-Phase Versus Three-Phase: Several factors influence the selection. For substation sizes used most frequently by rural electric systems, single-phase regulators (see Figure 5-11) are usually less expensive. They also do a better job of maintaining balanced phase voltages under conditions of unbalanced loading. Single-phase regulators are also more adaptable to line use because of the relative

ease of pole mounting. Regulation by single-phase regulators also gives maximum reliability for the system because a regulator can be removed for maintenance or repair without the need to de-energize transformers or other regulators. Special switches are available to permit removing a regulator from service without interrupting the circuit. These should always be provided.

In large distribution substations, the choice of three-phase regulators (see Figure 5-12) may be based on costs or on the availability of single-phase regulators of the required size. Three-phase regulators require somewhat less space than three single-phase regulators; however, this is not generally a major factor in selection.

Load-tap-changing power transformers are becoming more common in distribution substations. They consist essentially of a three-phase regulator built into a three-phase power transformer. The relative cost of this combination compared to a separate transformer and either three-phase or single-phase regulators varies depending on the size of the substation.

Aside from the base cost of the equipment, the LTC method generally will result in a saving in space, buswork, and supporting structures. Because their controls sense only one phase of a three-phase circuit and since some unbalance may be expected among the phases, the voltage correction of three-phase regulators and LTC transformers will be less precise than that of single-phase regulators.

Regardless of the selection of single-phase or three-phase regulators, a spare regulator for each substation is normally not justified.

5.5.3 Ratings

5.5.3.1   kVA Rating: The kVA rating of a single-phase regulator is the product of its rated load amperes and its rated range of regulation in kilovolts. For polyphase regulators, this product have to be multiplied by the appropriate phase factors (1.732 for three-phase regulators). The kVA rating of a 10 percent, 7620-volt, single-phase regulator capable of carrying a rated load current of 100 amperes would be:

$$kVA = 7.620 \text{ x } .10 \text{ x } 100 = 76.2 \text{ kVA}$$

In those cases where the range of regulation is different for the "raise" position than for the "lower" position, the larger percentage regulation is used to determine the regulator kVA rating.

The ratings for regulators generally are based on operation at 60 Hz with a range of regulation of 10 percent "raise" and 10 percent "lower" without exceeding the specified temperature rise at the given operating voltage. Regulator losses decrease as the regulator moves from the extreme tap positions (boost or buck) closer to the neutral point. Since the range of regulation required need not always be a full 10 percent, this allows for an extended range of regulator operation.

For the range of regulation of single-phase step regulators rated 19.9 kV and below, see Table 5-28.

For the range of regulation of three-phase, step-voltage regulators rated 13.8 kV and below, see Table 5-29.
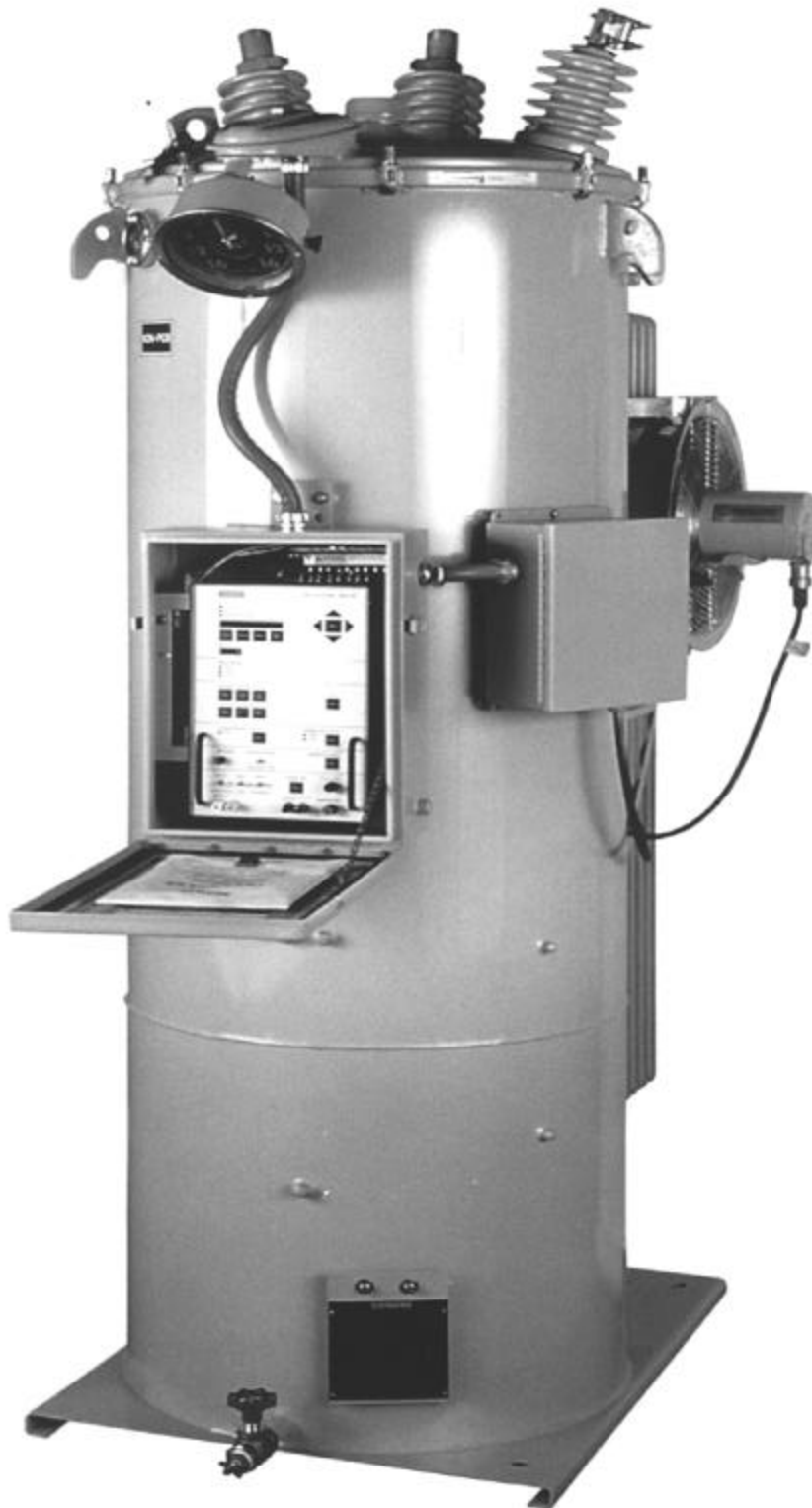
Figure 5-11: Single-Phase Voltage Regulator (Courtesy of Siemens)

Figure 5-12: Three-Phase Voltage Regulator (Courtesy of Siemens)

Table 5-28: Range of Regulation vs. Rated Current for Single-Phase Step Regulators
Rated 19.9 kV and Below. Ref. ANSI/IEEE Std. C57.15-1986, Section 5.4.
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Range of Voltage Regulation (Percentage)	Amperes as Percentage of Rated Current*
± 10	100
± 8.75	110
± 7.50	120
± 6.25	135
± 5.00	160

*Maximum current = 668 amperes.

Table 5-29: Range of Regulation vs. Rated Current for Three-Phase Step Regulators
Rated 13.8 kV and Below. Ref. ANSI/IEEE Std. C57.15-1986, Section 5.4.
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Range of Voltage Regulation (Percentage)	Amperes as Percentage of Rated Current**
± 10	100
± 8.75	108
± 7.50	115
± 6.25	120
± 6.00	130

**Maximum current = 600 amperes.

It can be seen from Tables 5-28 and 5-29 that if regulators are applied to circuits requiring only 5 percent regulation, their current-carrying capabilities can be extended to provide additional capacity—up to 160 percent in the case of single-phase regulators.

5.5.3.2   Voltage: Preferred voltage ratings of step-voltage and induction-voltage regulators based on a voltage range of 10 percent raise and 10 percent lower are given in Tables 5-30 and 5-31.

Substation regulators should be specified as being capable of providing a range of voltage regulation of ±10 percent and a bandwidth not greater than ±1 volt (on a 120-volt base).

Most regulators are specified with a ±10 percent range using thirty-two 5/8 percent steps.

5.5.3.3   Current: Preferred current ratings of oil-immersed step-voltage regulators are listed in Tables 5-30 and 5-31.

5.5.3.4   Temperature: ANSI Standard ratings of kVA, voltage, and current for air-cooled voltage regulators are based on ambient air temperature not exceeding 40°C and on the average temperature of the cooling air for any 24-hour period not exceeding 30°C. For loading under other conditions, see ANSI Std. C57.95, "Guide for Loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators."

The ratings are based on a temperature rise above the ambient in accordance with Table 5-32.

Table 5-30: Preferred Ratings for Oil-Immersed Step-Voltage Regulators
(Single-Phase). Ref. ANSI/IEEE Std. C57.15-1986, Table 3.
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Nominal System Voltage	BIL (kV)	kVA	Line Amperes
2400/4160Y	60	50	200
		75	300
		100	400
		125	500
		167	668
		250	1000
		333	1332
4800/8320Y	75	50	100
		75	150
		100	200
		125	250
		167	334
		250	500
		333	668
7620-13 200Y	95	38.1	50
		57.2	75
		76.2	100
		114.3	150
		167	219
		250	328
		333	438
		416	546
		509	668
		667	875
		833	1093
13 800	95	69	50
		138	100
		207	150
		276	200
		414	300
		552	400
14 400/24 940Y	150*	72	50
		144	100
		216	150
		288	200
		333	231
		432	300
		576	400
		667	463
		833	578
19 920-34 500Y	150*	100	50
		200	100
		333	167
		400	201
		667	334
		833	418

*Low-frequency test voltage 50 kV by induced test with neutral grounded.

Table 5-31: Preferred Ratings for Oil-Immersed Step-Voltage Regulators
(Three-Phase). Ref. ANSI/IEEE Std. C57.15-1986, Table 4.

Nominal System Voltage	BIL (kV)	Self-Cooled		Self-Cooled/Force Cooled	
		kVA	Line Amperes	kVA	Line Amperes
2400	45	500	1155	625	1443
		750	1732	937	2165
		1000	2309	1250	2887
2400/4160Y	60	500	667	625	833
		750	1000	967	1250
		1000	1334	1250	1667
4800	60	500	577	625	721
		750	866	937	1082
		1000	1155	1250	1443
7620/13 200	95	500	219	625	274
		750	328	938	410
		1000	437	1250	546
		1500	656	2000	874
		2000	874	2667	1166
7970/13 800Y	95	500	209	625	261
		750	313	937	391
		1000	418	1250	523
		1500	628	2000	837
		2000	837	2667	1116
		2500	1046	3333	1394
14 400/24 940Y	150	500	125.5	625	156.8
		750	188.3	937	235.4
		1000	251	1250	314
		1500	377	2000	502
		2000	502	2667	669
		2500	628	3333	837
19 920/34 500Y	150	500	83.7	625	104.6
		750	125.5	937	156.8
		1000	167	1250	209
		1500	251	2000	335
		2000	335	2667	447
		2500	418	3333	557
26 560/46 000Y	250	500	62.8	625	78.5
		750	94.1	937	117.6
		1000	126	1250	157
		1500	188	2000	251
		2000	251	2667	335
		2500	314	3333	419
39 840-69 000Y	350	500	41.8	625	52.5
		750	62.8	937	78.5
		1000	83.7	1250	105
		1500	126	2000	167
		2000	167	2667	223
		2500	209	3333	278

Table 5-32: Limits of Temperature Rise. Ref. ANSI/IEEE Std. C57.15-1986, Table 2.
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Item	Type of Apparatus*	Winding Temperature Rise by Resistance, ^{o}C	Hottest-Spot Winding Temperature Rise, ^{o}C
(1)	55°C Rise Liquid-Immersed	55	65
	55°C Rise Dry-Type	55	65
	80 ^{o}C Rise Dry-Type	80	110
	150 ^{o}C Rise Dry-Type	150	180
(2)	Metallic parts in contact with or adjacent to the insulation shall not attain a temperature in excess of that allowed for the hottest spot of the windings adjacent to that insulation.		
(3)	Metallic parts other than those covered in Item (2) shall not attain excessive temperature rises.		
(4)	Where a regulator is provided with sealed-tank, conservator, gas-oil-seal, or inert-gas-pressure systems, the temperature rise of the insulating oil shall not exceed 55°C when measured near the surface of the oil. The temperature rise of insulating oil in a regulator not provided with the oil preservation systems listed above shall not exceed 50°C when measured near the exposed surface of the oil.		

* Apparatus with specified temperature rise shall have an insulation system that has been proved by experience, general acceptance or accepted test.
NOTE: In the context of Item 1, dry-type apparatus is understood to refer to induction-voltage regulators.

5.5.3.5   **Altitude:** ANSI Standard ratings of voltage regulators are based on an altitude not exceeding 1000 meters (3300 feet). At higher altitudes, the decreased air density has an adverse effect on the temperature rise and the dielectric strength of voltage regulators. Table 5-33 gives correction factors for dielectric strength at altitudes above 1000 meters.

Table 5-33: Dielectric Strength Correction Factors for
Altitudes Greater Than 3,300 Feet (1,000 Meters)
Ref. ANSI/IEEE Std. C57.15-1986, Table 1.
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Altitude		Altitude Correction Factor for Dielectric Strength
Feet	Meters	
3,300	1,000	1.00
4,000	1,200	0.98
5,000	1,500	0.95
6,000	1,800	0.92
7,000	2,100	0.89
8,000	2,400	0.86
9,000	2,700	0.83
10,000	3,000	0.80
12,000	3,600	0.75
14,000	4,200	0.70
15,000	4,500	0.67

NOTE: Altitude of 15,000 feet is considered a maximum for standard regulators.

Table 5-34 gives a basis for loading above 1000 meters. Also, see ANSI Std. C57.95, "Guide for Loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators."

Table 5-34: Reduction Factors for Altitudes
Greater Than 1000 m (3300 ft). Ref. ANSI/IEEE Std. C57.95-1984, Table 2.
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Types of Cooling	Reduction Factor for Each 100 m Above 1000 m (%)
Liquid-immersed, self-cooled	0.4
Liquid-immersed, forced-air-cooled	0.5

1000 m (3300 ft), with an ambient temperature of 30°C.

NOTE: See ANSI/IEEE Std. C57.15-1986 [2], 4.3.2, for regulator insulation capability at altitudes above 1000 m (3300 ft).

5.5.3.6   Short-Circuit Strength: Regulators used on cooperatives' systems have to be capable of withstanding rms symmetrical short-circuit currents of 25 times the regulator full-load current for 2 seconds and 40 times the regulator full-load current for 0.8 seconds without injury.

Where short-circuit duty on the regulator exceeds its capabilities, current-limiting reactors may be installed in the substation to limit the available fault current.

5.5.4 Regulator Controls

5.5.4.1   General: Regulators are equipped with a number of devices and controls that allow the operator to use the regulator effectively. These include means for setting or adjusting the voltage level, bandwidth, time delay, range of regulation, and line drop compensation.

Since a change in the setting of any one of these devices will directly affect the operation of one or more of the other devices, they are all treated as a unit comprising what is known as the regulator control system. In earlier regulators, the components of this control system were electromechanical, but regulators manufactured since about 1963 are equipped with static-type devices featuring solid-state or microprocessor components. The setting of the individual devices in the newer control systems is based on the same principles. They are, in general, easier to set than the older mechanical type.

The various devices used in the control system are almost all adjusted at the control panel. One exception is the range of regulation, which is made at the position indicator mounted on the regulator. The control panel can be mounted directly on the regulator or remote from the regulator.

Microprocessor controls are available with many different options. These options include power and energy metering, harmonics analysis, event logging, and communication packages.

For a brief description of the control devices and the settings recommended by RUS, see Bulletin 1724D-114.

5.5.4.2   Control System Accuracy: The individual components utilized in the regulator control system are accurate devices and, as such, they enable the regulator to obtain a level of efficiency sufficient to meet Class I accuracy requirements. Class I accuracy means that the sum of errors in the

control circuit taken individually cannot total more than ±1 percent. A plus error would be one causing the regulator output to be higher than the reference value, while a minus error would be one causing the regulator output to be lower than the reference value.

Because of this accuracy and, more importantly, because of its function in maintaining system voltage levels, the voltmeters and other instruments used in conjunction with regulators should be as accurate as the regulator. To utilize measuring equipment any less efficient than this deprives the system of the regulator's full capabilities.

5.5.5 Lightning Protection

Voltage regulators, like other elements of the distribution system, require protection from lightning and other high-voltage surges. Because voltage regulators are constructed like autotransformers, having one of the windings in series with the primary line, additional protection is required for this series winding. Regulators are normally factory equipped with bypass arresters across this series winding; these arresters may be connected internally or externally, depending on the manufacturer. The bypass arrester limits the voltage developed across the series winding during surges to within safe values.

> **CAUTION:** Bypass arresters protect only the series winding of the regulator
> and do not eliminate the need for arresters to protect the regulator itself.

5.5.6 References

ANSI Std. C57.15, "Requirements, Terminology, and Test Code for Step-Voltage and Induction-Voltage Regulators."

ANSI Std. C57.95, "Guide for Loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators."

ANSI Std. C84.1, "Voltage Ratings for Electric Power Systems and Equipment (60 Hz)."

RUS Bulletin 1724D-112, "The Application of Shunt Capacitors to the Rural Electric System."

RUS Bulletin 169-4, "Voltage Levels on Rural Distribution Systems."

RUS Bulletin 1724D-114, "Voltage Regulator Application on Rural Distribution Systems."

RUS Bulletin 50-90 (S-2), "Specification for Substation Regulators."

5.6 SHUNT CAPACITOR EQUIPMENT

5.6.1 General

Shunt capacitor banks at substations improve power factor and voltage conditions by supplying leading kilovars to transmission and distribution systems. For the criteria to determine the need for capacitors and selecting size, location, etc., refer to RUS Bulletin 1724D-112, "The Application of Shunt Capacitors to the Rural Electric System."

IEEE Std. 1036, "IEEE Guide for Applications of Shunt Power Capacitors," provides guidelines for the application, protection, and ratings of equipment for the safe and reliable utilization of shunt power

capacitors. NEMA Std. CP-1, "Standards Publication—Shunt Capacitors," also provides guidelines for the application of shunt capacitors.

Consult RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers," for accepted manufacturers' types of individual capacitor units.

5.6.2   System Considerations

5.6.2.1   General: Evaluate system issues, including the effects of switching transients and potential harmonic resonance, with each bank installation. Shunt capacitor banks alter an electrical system's response to disturbances, which can impair system performance.

Specific issues that designers should consider include transients caused by bank energization and potential resonance conditions.

5.6.2.2   Switching Transients

5.6.2.2.1 Bank Energization: Transient voltages and currents occur whenever shunt capacitor banks are energized. Overvoltages can reach twice the system voltage, with inrush currents ranging from 5 to 15 times normal steady-state current. Transient magnitude and duration depend on the natural damping provided by the circuit's resistive elements. Transient voltages and current resulting from capacitor switching have to be controlled to avoid exceeding equipment capabilities and damaging customers' sensitive electronic equipment.

ANSI/IEEE Std. C37.012, "IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis," provides guidelines for calculating transient inrush and discharge currents. It is important that the design engineer calculate the peak magnitude and frequency of these transient currents to compare to the capabilities of the shunt capacitor bank's equipment and adjoining substation equipment.

5.6.2.2.1.1 Isolated Bank Switching: The transient inrush current to a single isolated bank is less than the available short-circuit current at the capacitor location. Since a circuit breaker has to meet the momentary current requirement of the system, transient inrush current is not a limiting factor for this application. However, the momentary rating of other switching devices not intended for fault current interruption should be checked.

5.6.2.2.1.2 Back-to-Back Switching: Figure 5-13 illustrates a typical arrangement for two capacitor banks switched back to back. Capacitor banks switched back to back (one being energized when another is already connected to the same bus) produce transient currents of high magnitude and high frequency that flow between the banks on closing of the switching device. The oscillatory current is limited only by the impedance of the capacitor banks and the circuit between them and usually decays to zero in a fraction of a cycle of the power frequency. The component supplied by the power source is usually so small it may be neglected.

Additional impedance between capacitor banks may be required in the form of inductors to allow for back-to-back switching. (See Section 5.6.2.2.4.)

5.6.2.2.1.3 Induced Voltage: The magnetic fields associated with high inrush current during energization of shunt capacitor banks (isolated bank or back-to-back switching) in either the overhead
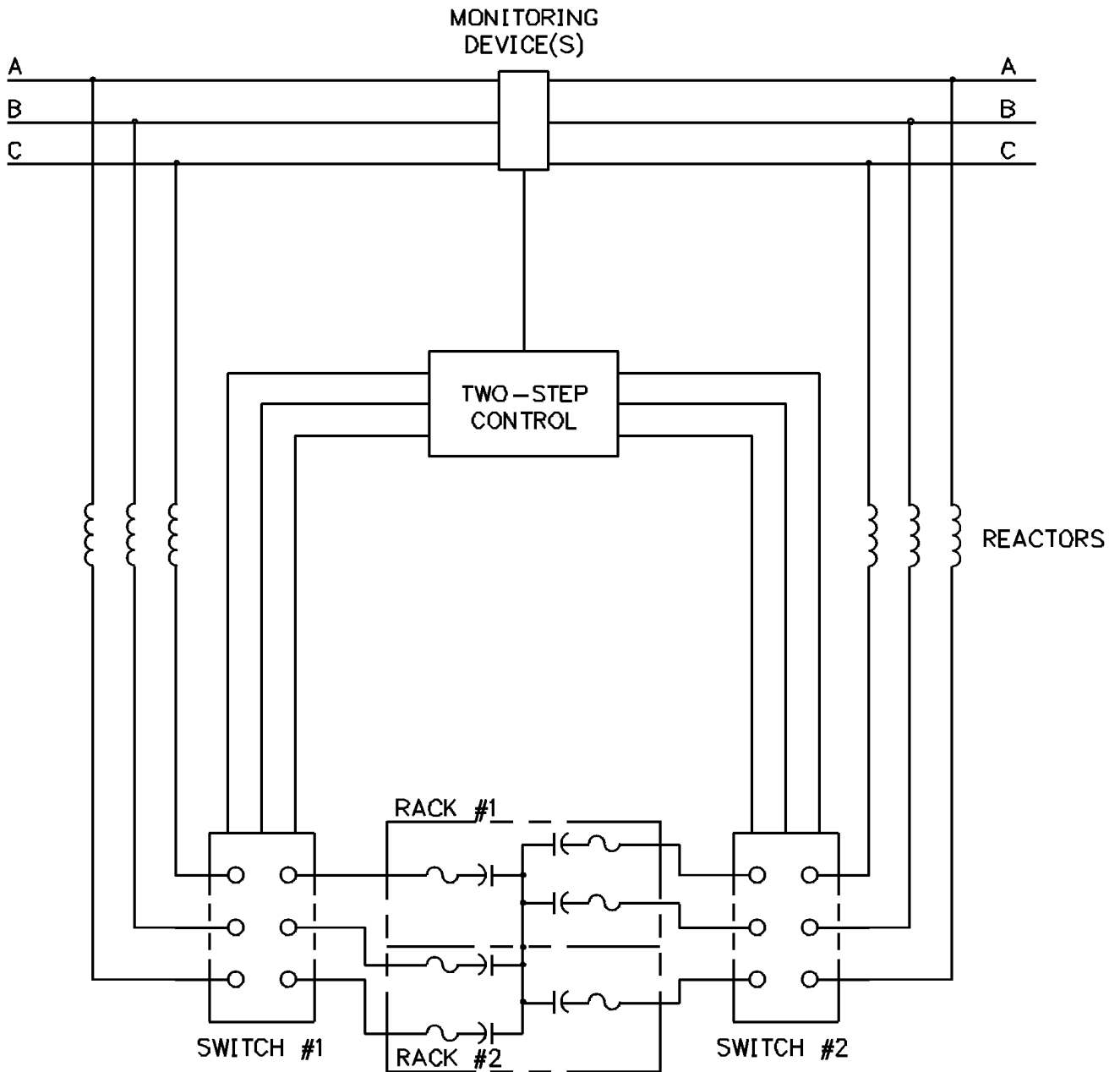
Figure 5-13: Typical Capacitor Bank—Two Three-Phase Capacitor Racks Connected
to Form a Two-Step Bank, Floating Wye with a Common Neutral

conductors or the grounding grid can induce voltages in control cables by both electrostatic and
electromagnetic coupling. These induced voltages can be minimized by shielding the cables, using a
radial configuration for circuits (circuits completely contained within one cable so inductive loops are not
formed), and single-point or peninsula grounding of the capacitor banks. (See ANSI/IEEE Std. C37.99,
"IEEE Guide for the Protection of Shunt Capacitor Banks," for definitions of these types of grounding
configurations.)

5.6.2.2.1.4   Voltage Amplification: Applying capacitor banks at more than one voltage level in an interconnected system can result in voltage amplification that can cause nuisance tripping of adjustable-speed drives, damage to surge suppressors on low-voltage equipment, and, possibly, adverse effects to sensitive electronic equipment.

Voltage amplification occurs when switching transients, initiated by capacitors located on primary systems, become amplified at capacitors located on secondary systems. The reason is that the frequency of the transient initiated by the primary system capacitor approximates the resonant frequency of the circuit formed by the step-down transformer located in series with secondary system capacitors.

5.6.2.2.2   Control of Switching Transients: The magnitude of switching transients caused by capacitor bank switching may be greatly reduced by adding current-limiting reactance in series with the bank or through application of transient control switching devices.

5.6.2.2.1.1   Transient Control Switching Devices: Transient-control switching devices limit the effects of capacitor switching. Three common methods are used:

  1.   Fitting circuit switchers with pre-insertion inductors
  2.   Adding pre-insertion resistors to circuit breakers
  3.   Incorporating vacuum switches with synchronous closing control

The first two methods momentarily insert an impedance electrically in series with the capacitor bank when it is energized, dampening transient voltages to acceptable levels. The third method, synchronous closing, attempts to energize each phase of a three-phase capacitor bank at the instant the applied voltage crosses zero. This is achieved through synchronous control of the bank's independent pole vacuum switches.

Theoretically, "zero-voltage control" eliminates switching transients. However, experience shows this technique only lowers switching transients because the switching device's electrical and mechanical tolerances provide only near-zero-voltage closing.

5.6.2.2.3   Bank De-Energization: Capacitive switching devices have to be capable of providing sufficient dielectric recovery when interrupting capacitive current or the current arc will ignite or "restrike." A single restrike results in a transient voltage three times system voltage.

Modern capacitor switching devices rarely restrike. However, use caution to ensure shunt capacitors do not inadvertently de-energize through operation of upline circuit breakers because an underrated circuit breaker could potentially cause restrike. Voltage transients initiated by restrike have been known to cause catastrophic capacitor bank failures.

5.6.2.2.4   Current-Limiting Reactance: It may be necessary to provide inductive reactance in the form of current-limiting reactors to limit inrush current during capacitor bank switching.

Sometimes adequate impedance to limit the inrush current to the rating of the switch may be obtained by physically locating the banks as far apart from one another in the substation as possible. In other cases, it may be necessary to provide inductive reactance in the form of current-limiting reactors between parallel switched capacitor banks.

To limit the peak inrush current to "kA" in a substation of "n" equal-size parallel capacitor banks, of

"MVAR" megavars per phase each at "f" hertz, provide a current-limiting reactor in each phase of each bank of "L_T" microhenries per phase, according to Equation 5-4:

Equation 5-4

$$L_T = \frac{MVAR \cdot 10^6 \cdot (n-1)}{(kA)^2 \cdot \pi \cdot f \cdot n}$$

Where:

L_T	=	Required inductance, μH
MVAR	=	Megavars per phase at 60 Hz
n	=	Number of parallel banks
f	=	Frequency, Hz
kA	=	Maximum allowable inrush current, kA
ð	=	3.1416

Example 5-1 shows a typical inrush current calculation for back-to-back switching involving Equation 5-4.

Example 5-1
Typical Inrush Current Calculations—Back-to-Back Switching

Two capacitor banks, each 13,500 kVAR, 14,400 volt, 60 Hz, both switched by 15 kV vacuum switches, rated for 20,000-ampere momentary peak:

$$L_T = \frac{4.5 \times 10^6 \times (2-1)}{20^2 \times \pi \times 60 \times 2} = 29.8 \, \mu H$$

Where:

MVAR	=	$13 - 5/3 \geq 4.5$
n	=	2
kA	=	20
f	=	60
ð	=	3.1416

For this case, the equipment design would probably specify a 30 μH, 600-ampere reactor in each phase of each bank.

In determining the continuous current rating of the reactor, the increase in current due to applied voltage, capacitance tolerance, and harmonics should be considered. As discussed in Section 5.6.6.1, it is considered adequate to use a total multiplier of 1.25 and 1.35 for ungrounded and grounded banks, respectively. Assuming that the banks are ungrounded, the minimum continuous rating for each reactor would be:

$$I = (1.25)\frac{kVAR}{kV \times 3^{1/2}} = (1.25)\frac{4.5 \times 3}{14.4 \times 3^{1/2}} \times 1000 = 676 \, amps$$

If the capacitor manufacturer determines and supplies all accessory equipment, including switches and reactors, it is necessary to inform the manufacturer of the total MVAR in the substation, the inductive

reactance of the bus between the capacitor banks, and system available fault current. This will allow the manufacturer to calculate the ratings of any required reactors. When physically locating these reactors, take care to space them as far apart as practical to minimize the effect of mutual reactance. The reactors' continuous current ratings should be at least equal to the continuous current ratings of the switches they protect and should meet the requirements of IEEE Std. C57.16, "IEEE Standard Requirements, Terminology, and Test Code for Dry-Type Air-Core Series-Connected Reactors."

5.6.2.3 Resonance: Resonance occurs whenever an electrical circuit's inductive and capacitive reactances—connected either in parallel or series—are equal at some frequency. A shunt capacitor bank forms a resonant circuit with system inductive elements. This resonance condition can be excited by remote system disturbances such as remote bank switching or sources of harmonic current. Resonance can cause excessive overvoltages and currents possibly resulting in failure of equipment such as capacitors, surge arresters, instrument transformers, and fuses.

5.6.2.4 Harmonic Resonance: Capacitor banks may resonate with harmonic currents produced elsewhere on the system. Harmonic-current flow into the capacitor bank may excite parallel resonance between the system inductance and bank capacitance. Parallel resonance causes high oscillating currents between inductive and capacitive energy-storage elements. High oscillating currents cause excessive voltage distortion.

Installing current-limiting reactors in series with the shunt capacitor bank can "tune" the bank to the offending harmonic's frequency and eliminate parallel resonance. Essentially, a single-tuned filter is formed by the bank's resistive, inductive, and capacitive elements. The bank traps harmonic current to which it is tuned. Parallel resonance is avoided since harmonic current cannot flow between the system inductance and the bank's capacitance.

IEEE Std. 519, "IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Systems," suggests acceptable harmonic-current levels industrial users can inject into supplying utility systems and the quality of voltage that the utility should supply.

5.6.3 <u>Types</u>

Shunt capacitor bank designs include open-rack and metal-enclosed bank designs. Open-rack substation capacitor banks are used to provide large blocks of kilovars on distribution and transmission systems at voltages up to 765 kV. Metal-enclosed substation capacitor banks are used to apply medium-size blocks of kilovars on distribution systems up to 34.5 kV where a completely enclosed assembly is advantageous for space or safety reasons.

5.6.3.1 Open-Rack Substation Capacitor Bank: This type of capacitor bank design mounts capacitor units vertically or horizontally in aluminum or galvanized steel frames. Ancillary devices including switching equipment, instrument transformers, and surge protection are mounted on separate structures.

This type of capacitor bank can be furnished with all phases in a single rack or with only one phase in a single rack. The largest standard "upright" rack usually holds 40 capacitor units, and the largest "edge-mount" rack usually 32 units. These racks are generally furnished complete with individual capacitor units, unit fuses, insulators, supporting structure, and other equipment necessary for a complete installation.

Open-rack capacitor banks have many exposed, live components and have to be enclosed with a fence. A key interlock system can be used to prevent entry into the enclosure until capacitors are properly

grounded. This bank design is susceptible to rodent-related failures since chain-link fences do not keep out all rodents. Additionally, adequate electrical clearances have to be provided for exposed live parts and external expulsion fuses, which results in a large footprint for most open-rack capacitor banks.

For most substation applications in open racks, individual capacitor units are equipped with only one bushing. The second bushing is often unnecessary when the racks themselves form a part of the circuit and are insulated by means of base insulators. In a three-phase delta-connected rack, however, two bushing units are required.

Open-rack capacitor banks use capacitor units that are protected through external fuses.

5.6.3.2 Metal-Enclosed Substation Capacitor Bank: This type of capacitor bank design completely encloses the bank's components within a grounded structure, which eliminates the need for a fenced enclosure and mitigates rodent problems. Enclosed capacitor banks are more aesthetically pleasing compared to open-rack capacitor banks. The capacitor bank assembly is generally furnished with internally fused capacitor units, insulators, current-limiting reactors, vacuum switches, grounding switches, main line fusing, line disconnect switches, surge arresters, instrument transformers, protection, monitoring and control devices, and a cable entrance section. The doors of the enclosure are key interlocked to prevent entry into a live compartment.

Enclosed capacitor banks generally use internally fused capacitor units that are compact in design and more reliable compared to externally fused capacitor units.

Enclosed capacitor banks can be completely pre-assembled and shipped to a project site.

5.6.4   Bank Configuration

A capacitor bank of a given size and voltage rating may be made up of a number of series and parallel groups. Use of capacitors with the highest possible voltage rating results in a bank design with the fewest number of series groups, which provides for the most economical design and greatest sensitivity for unbalance detection schemes.

The maximum and minimum number of capacitor units in parallel per series group is limited by capacitor unit design considerations regarding permissible overvoltages and avoidance of case rupture. It is important in any capacitor installation to ensure that the maximum operating voltages do not exceed 110 percent of the rated voltage of any capacitor. Because of this, the number of parallel capacitor units in each series section is selected so that the loss of any one unit in any series section will not result in such overvoltage. Additionally, steady-state voltage rises introduced by the flow of harmonic currents into tuned shunt capacitor banks (banks fitted with current-limiting reactors) have to be considered.

ANSI/IEEE Std. C37.99 provides recommendations for the maximum and minimum number of parallel capacitor units per series group.

Where only one series section of paralleled capacitors per phase is used and connected either three-phase grounded wye or delta, the unit capacitor fuse is subjected to full system short-circuit available current when its associated unit fails. This generally requires that more expensive, high-interrupting-capacity, current-limiting fuses be applied in situations where available fault currents exceed 4 kA. One advantage is that these banks can be designed in very small sizes without encountering unacceptable overvoltages on the remaining capacitors in a phase when one or more capacitors in that phase fails and clears, which

simplifies the protection scheme. For open-rack designs, the racks themselves do not have to be insulated from ground, thus saving the cost of base insulators.

When a three-phase wye connection is used with only one series section of paralleled units per phase, it is advantageous from a fusing standpoint to leave the neutral floating. This allows the unfaulted phases to limit the fault current supplied to the faulted phase. The fuse on the faulted unit will "see" a maximum of only three times normal bank phase current. While this may still be considerable current for large equipment, it is far less than usually available from the system, and a much less expensive, low-interrupting-capacity fuse can be applied. A (low) calculated risk is taken of simultaneous failure of units in different phases. It should be noted that, in a floating wye connection, the neutral has to have full line insulation between it and ground as well as sufficient ground clearances.

A double-wye configuration is often used where large amounts of kVAR are desired and the equipment is to be equipped with low-interrupting-capacity expulsion fuses. Designing this bank with connected multiple series groups limits the maximum fault current so that individual current-limiting capacitor fuses are not usually required unless the parallel kVAR exceeds 4,650 kVAR, in accordance with ANSI/IEEE Std. C37.99. Double-wye banks with only single series groups do not limit the maximum fault current. Therefore, individual capacitor fuses have to be capable of interrupting the system available fault current. Figure 5-14 illustrates a typical Y-Y connected capacitor bank with one series section per phase and neutrals isolated.

Delta-connected capacitor banks are generally applied only on lower voltage (23 kV or below) systems where the system voltage equals the voltage rating of a unit capacitor. They have to also be properly insulated from ground. Additionally, where one series group per phase is used, individual capacitor unit fuses should be capable of interrupting the system short-circuit phase-to-phase fault current. This usually requires the use of current-limiting fuses.

5.6.5   Ratings

5.6.5.1 Circuit Voltage: Domestic manufacturers can supply individual capacitor units in voltages ranging from 2.4 to 25 kV. Units of the same or of different voltage ratings can be mixed to obtain the required circuit voltage. Most cooperatives utilize capacitor equipment at or above 7.2 kV.

The desired circuit voltage is obtained by connecting as many capacitor groups in series as necessary to obtain the required voltage. Usually, the best engineering choice is to use the fewest number of series groups as possible. Use of capacitors with the highest possible voltage rating results in fewer series groups. This generally provides the simplest and most economical bank design. However, inventory or other economic considerations may override this rule.

5.6.5.2 kVAR Rating: Capacitor unit ratings available from domestic manufacturers undergo frequent change in order to provide the most practical and economical sizes for existing conditions. In general, the trend is toward larger unit sizes. Standard capacitor units for shunt capacitor bank applications are 50, 100, 150, 200, 300, and 400 kVAR. No upper limits are defined for internally fused capacitor units. These units are typically sized based on minimizing the number of capacitor units to minimize the bank's physical size while avoiding overvoltage and unbalance conditions with a substantial loss of a capacitor unit's individually fused elements.
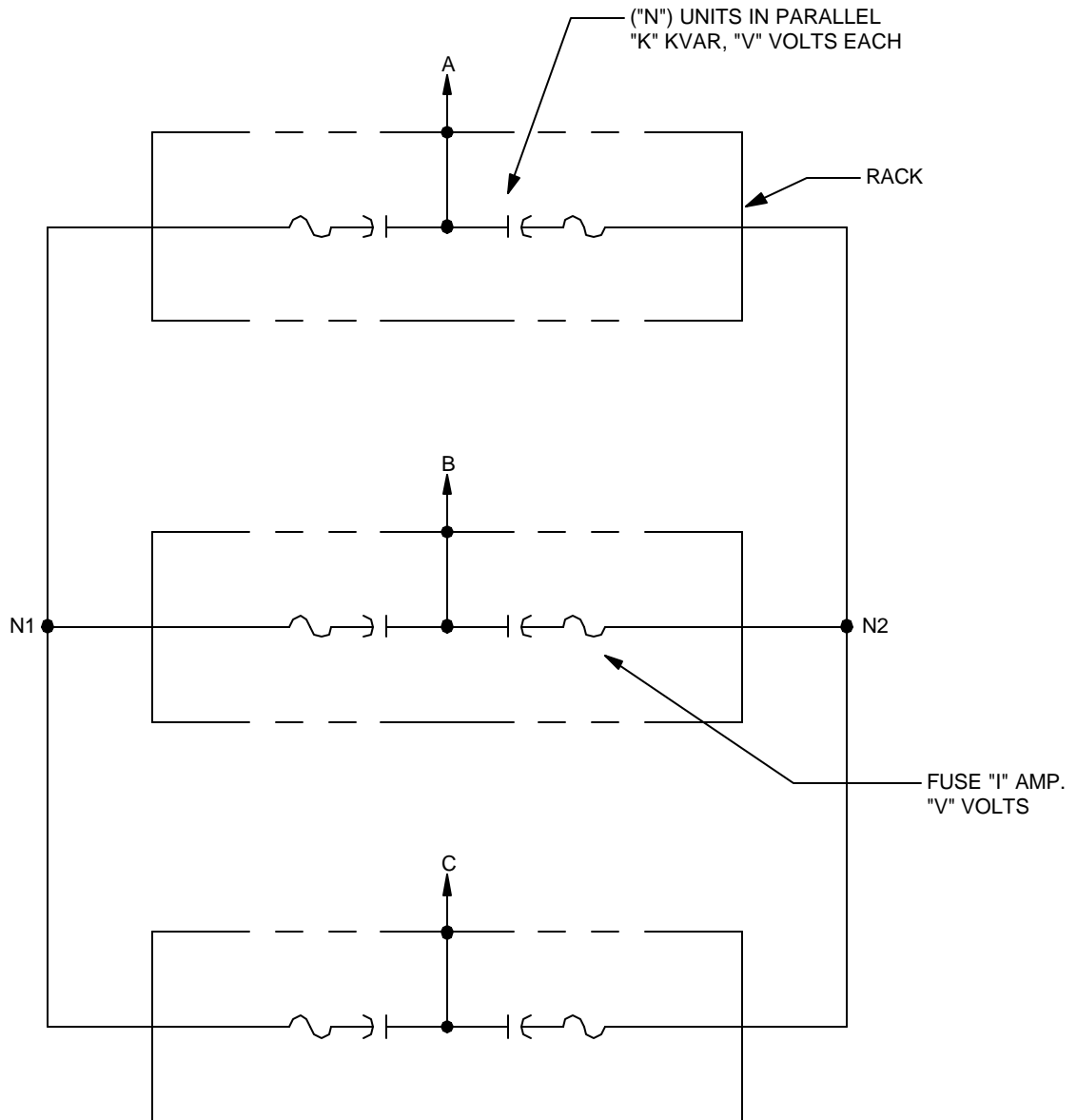
Figure 5-14: A Y-Y Connected Capacitor Bank with One Series Section per Phase and Neutrals Isolated

The capacitor manufacturer's recommendations should be considered in determining the optimum size of capacitor unit, number of series sections, number of units in parallel, and type of connection to make up the kVAR requirement for a given application.

5.6.5.3 Basic Insulation Level: Basic impulse insulation levels of individual capacitor units range from 75 to 200 kV. Table 5-35 summarizes typical basic impulse insulation levels by capacitor unit voltage rating.

5.6.5.4 Temperature: The maximum allowable ambient temperature for capacitor equipment installed outdoors with unrestricted ventilation is 40°C (104°F) based on the mathematical average of hourly readings during the hottest day expected at the site. Isolated, multiple row and tiers and metal-enclosed or

Table 5-35: Capacitor Unit Voltage and BIL Ratings. Ref. IEEE Std. 1036-1992.
Based on Table 3. Copyright © 1992. IEEE. All rights reserved.

Capacitor Voltage Rating (Volts, rms)	BIL (kilovolts)
2,400 – 4,800	75
6,640 – 12,470	95
13,280 – 14,400	95 and 125
15,125 – 19,920	125
19,920*	125 and 150
19,920 – 24,940*	150 and 200

* Single bushing units only.

housed units will have maximum ambient ratings of 46°C, 40°C, and 40°C, respectively. Capacitors are designed for continuous operation at –40°C (–40°F). Where the expected in-service ambient temperatures are lower than –40°C, the manufacturer should be consulted.

5.6.6 Switching

5.6.6.1 Switching Devices: The various devices that may be used for capacitor switching include those listed in Table 5-36.

Table 5-36: Switching Devices

Circuit Breakers	Interrupter Switches
Air	Oil
Air-Magnetic	SF$_6$
Oil	Vacuum
SF$_6$	
Vacuum	

When a capacitor bank is energized or de-energized, current and voltage transients are produced that affect the capacitor bank on the connected system. All capacitor switching devices should be applied within their maximum voltage, frequency, and current ratings, including transient inrush current and frequency.

The switching device should have a voltage rating at least equal to 10 percent above rated capacitor voltage since capacitors can be continuously operated at this voltage.

Select the switching device's continuous current rating based on consideration of factors that increase current flow in the capacitor bank. Multiplying factors are generally applied to include the effects of overvoltage (1.10), capacitor tolerance (1.05 to 1.15), and harmonic component (1.05 for ungrounded capacitor banks: 1.10 for grounded capacitor banks). It is usually considered adequate to use a total multiplier of 1.25 for ungrounded operation and 1.35 for grounded operation. (See ANSI/IEEE Std. C37.99.)

It is important to understand that most switching devices are derated for capacitor switching. A switching device's rated capacitance switching capability is usually well below the device's continuous current rating.

It is important to select a switching device designed for the application's specific duty to avoid potentially damaging overvoltages.

ANSI/IEEE Std. C37.04, "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis"; ANSI Std. C37.06, "American National Standard for Switchgear—AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis—Preferred Ratings and Related Required Capabilities"; and ANSI/IEEE Std. C37.012, "IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis," provide rating and application information for switching devices.

5.6.6.2 Controls: Controls for capacitor switching devices may operate in response to various signals such as voltage, current, VAR, temperature, time, or some combination of these. A variety of options is available in terms of price, features, and quality. These range from high-priced panel-mounted to low-priced socket-mounted controls. In recent years, capacitor controls based on electromechanical relays have been superseded by more modern electronic types including solid-state and microprocessor-based controllers. See Figures 5-15 through 5-18 for typical schematics of various capacitor control arrangements.

Control and application of capacitors are such closely related subjects that a discussion of one has to necessarily involve the other. In fact, in the typical situation, both the type of control and its adjustment are dictated by the objectives of the capacitor installation.

Capacitor switching controls provide outputs that are basically single-pole, double-throw switches activated by control signal(s) selected to reflect kVAR requirements. Theoretically, at least, any intelligence that changes only when a change in the kVAR supply is needed can be utilized to switch capacitors automatically. In practice, however, selecting a signal that accurately reflects the requirements of the system often turns out to be the most difficult part of the problem. The single-input types, such as voltage and time controls, are generally less expensive in initial cost and installation, less complex, and easier to adjust but less flexible in application than the dual-input types such as kilovar and current-biased voltage controls.

The selection of a control for a particular switched capacitor bank requires careful evaluation of several related factors. Some of the more important considerations are listed below. No attempt has been made to list them in any particular order, since their relative importance and probably even the factors themselves will vary considerably from one system to another.

- Purpose—The purpose of the bank affects selection of the appropriate controller. The purpose may be to reduce losses, improve voltage under normal or emergency operating conditions, reduce thermal loading of lines and equipment, etc.

- Location—The location of the bank affects what control parameter best represents changes in kVAR requirements. The bank's location influences whether voltage will drop appreciably as load increases, whether direction of feed is likely to change frequently because of normal or emergency circuit rearrangements, etc.

- Coordination—Coordination with related supplementary voltage regulation equipment including switched capacitors and voltage regulators affects the type of control strategy to be implemented.
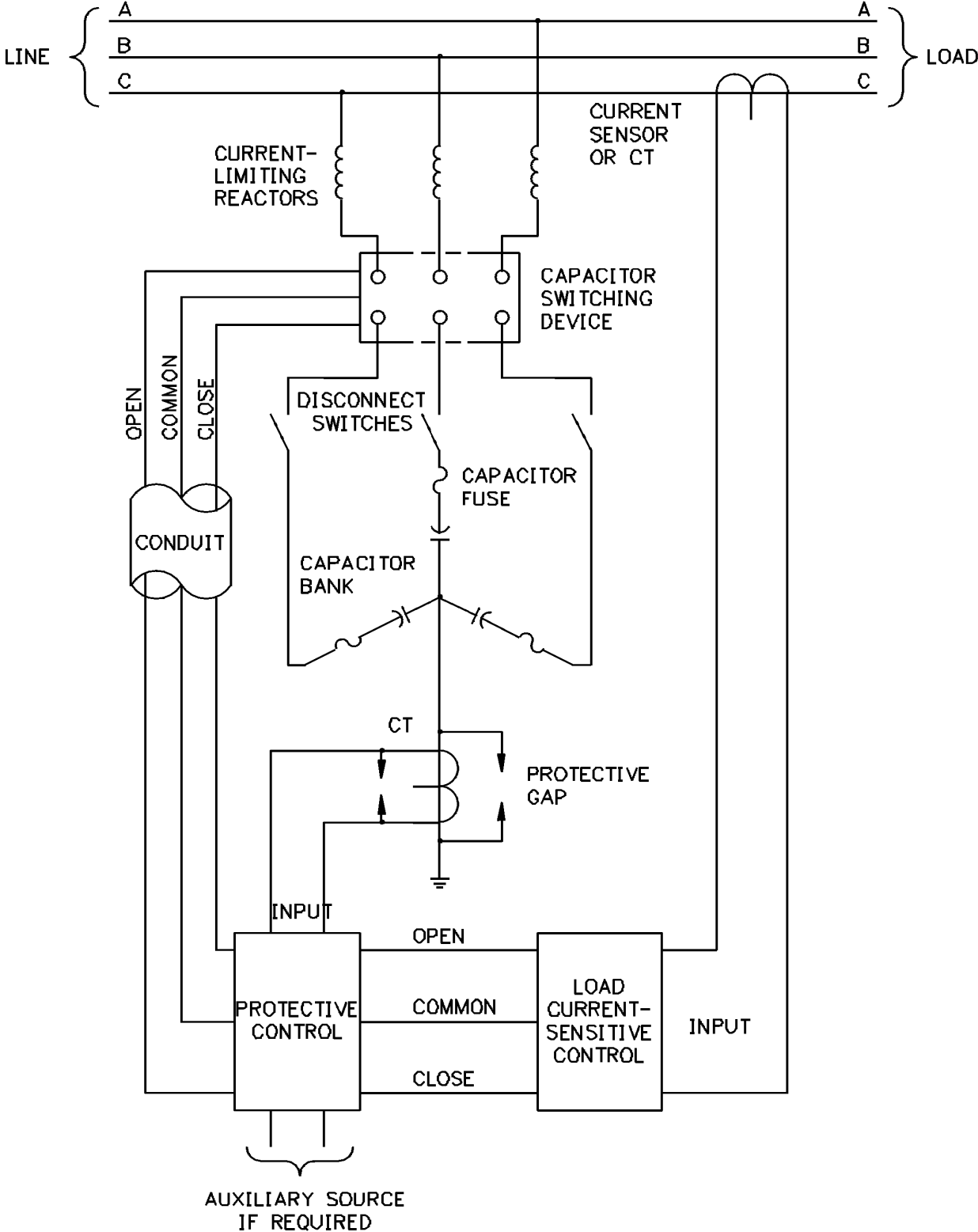
Figure 5-15: Typical Capacitor Bank Grd Wye Connected
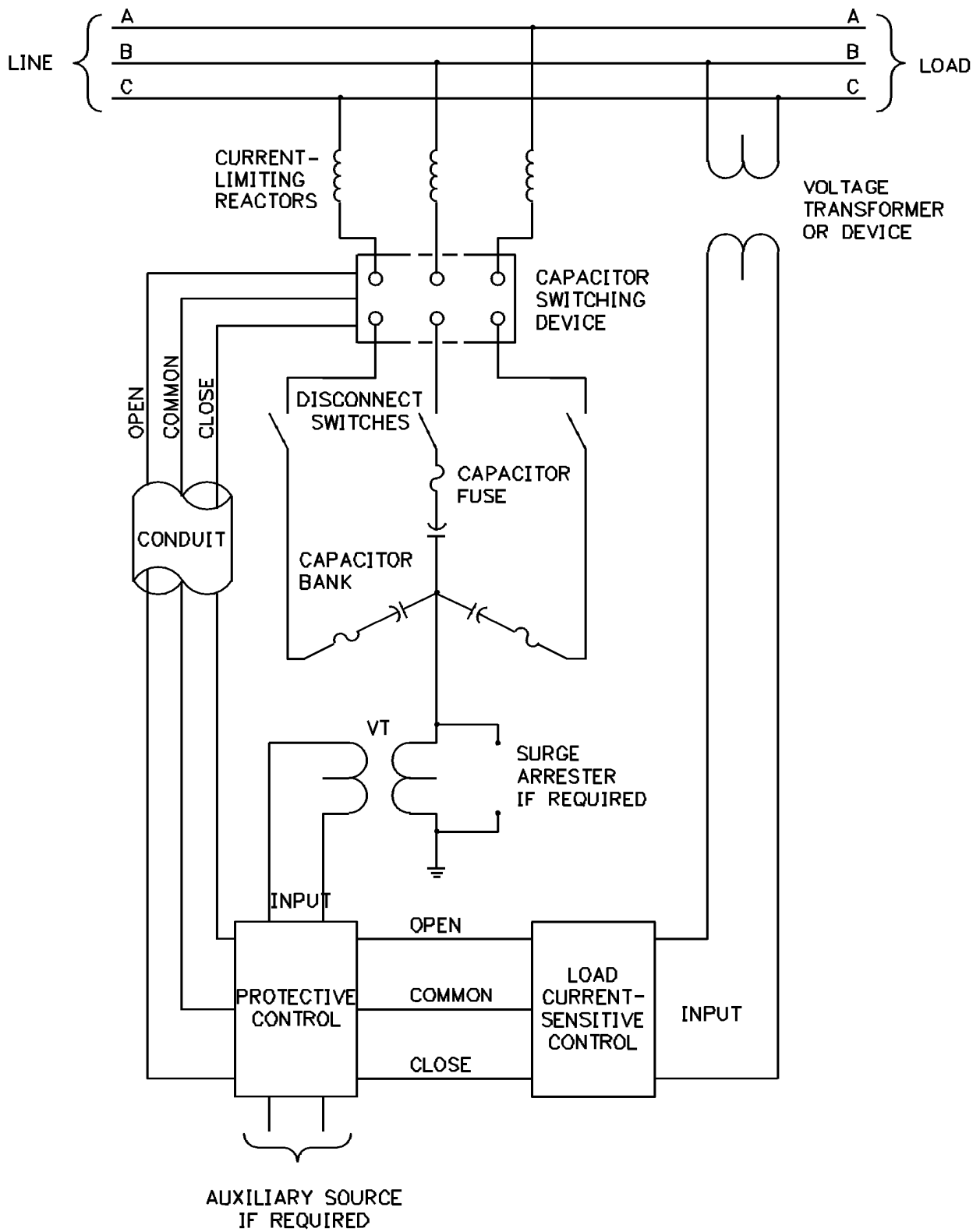
Figure 5-16: Typical Capacitor Bank Floating Wye
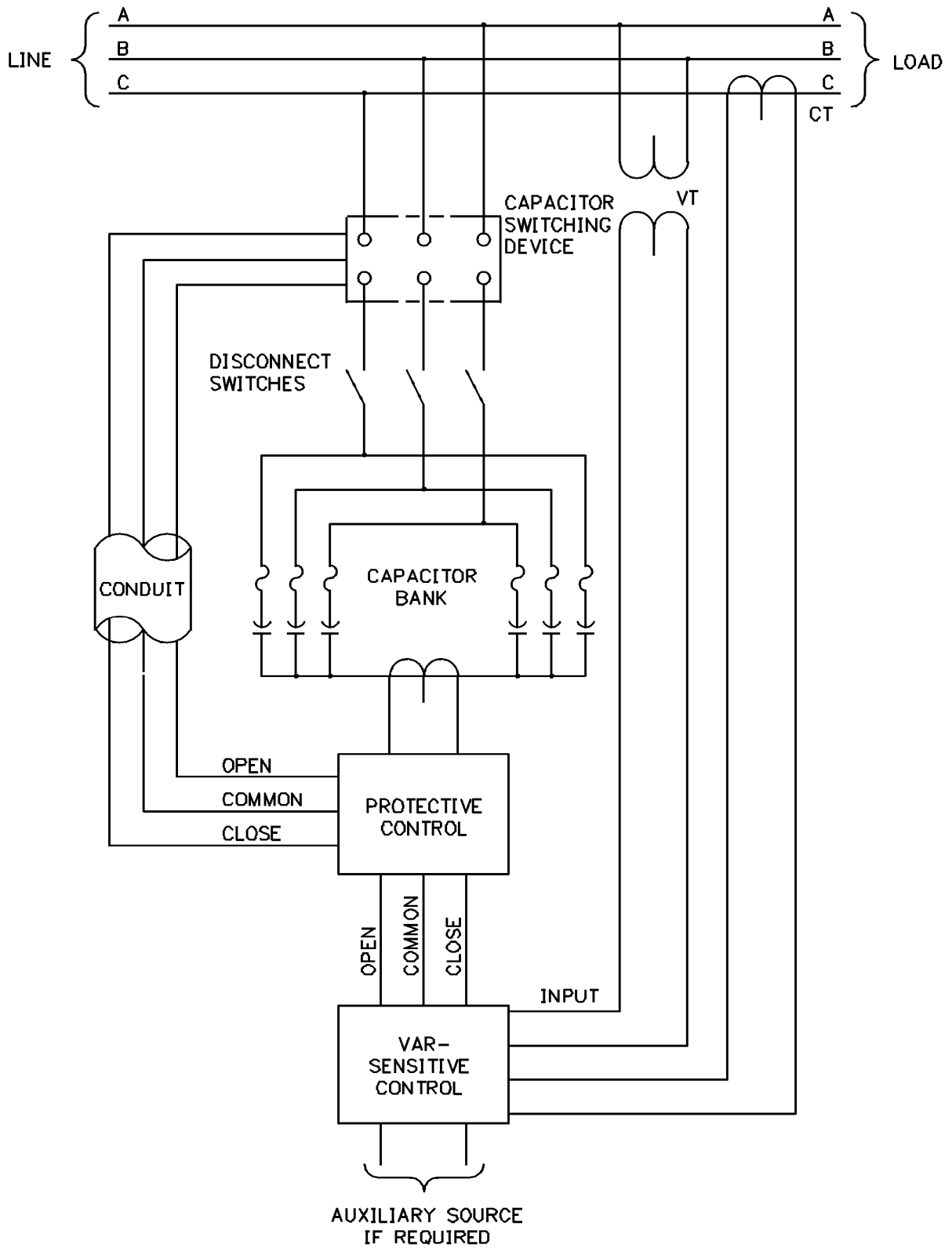
Figure 5-17: Typical Capacitor Bank Wye Wye Connected
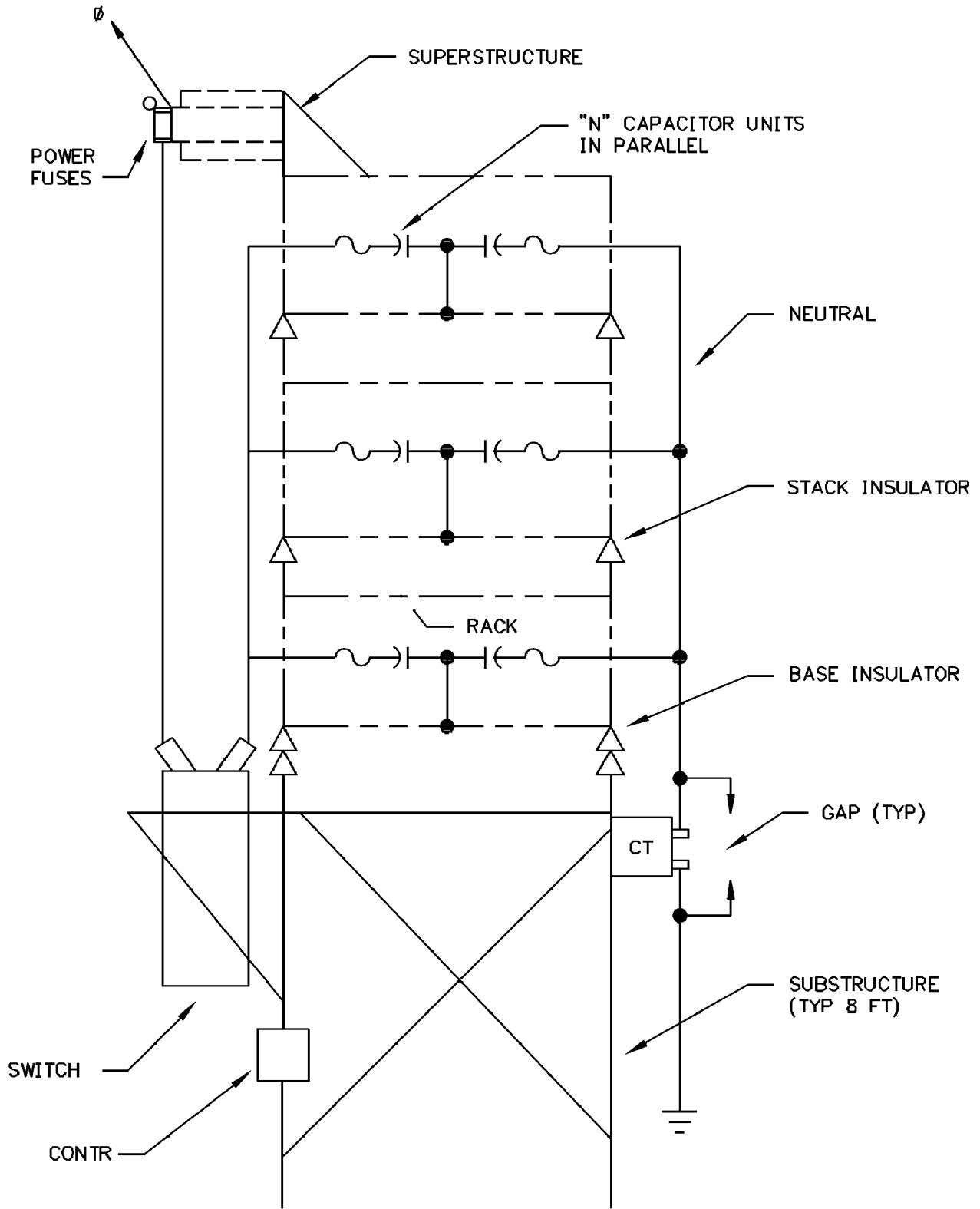
Figure 5-18: A Complete Typical Capacitor Equipment Connected Grd Wye with
Two Series Sections/Phase in a Single Stack

- Cost—The cost to implement each control strategy varies depending on sophistication and whether potential, current, or both inputs are required and the required control and auxiliary equipment (operating transformer, control secondary, current transformer, etc.).

The optimum choice of control will always be the least expensive type that will switch the capacitor bank on the required schedule. To facilitate comparison, the operating characteristics and relative cost of common controls used are summarized in Table 5-37:

Table 5-37: Comparison of Operating Characteristics of Capacitor Controls

Type of Control	Advantages	Disadvantages
Manual	No control device necessary since the bank's switching device is operated by substation personnel.	Requires attendants at the substation.
Time	Non-electrical control input allows application at any point on the circuit.	Can only be applied on feeders where power factor and demand have a regular daily variation that is repeated weekly. Use limited to locations where established switching schedule will not cause high voltage on holidays or during other abnormally light load periods. Insensitive to abnormal voltage conditions.
Temperature	Non-electrical input allows application at any point on the circuit. Connects capacitors when the outside ambient temperature exceeds a temperature set point.	Can only be applied where direct correlation with load increases and temperature can be established such as air conditioning loads.
Voltage	Applies and removes shunt capacitors when system voltages operate outside of allowable voltage tolerances.	Can only be applied where voltage drops appreciably under load. More difficult to coordinate with voltage regulators and other switched capacitor banks. Requires separate potential transformer.
Current	Can be applied at any point on the circuit where the load current can be monitored. Nondirectional. Responds to current changes. Current and voltage source available for general testing on feeder.	Requires current transformer. Adjustment slightly more complex than other controls.
Kilovar	Most effective in minimizing losses because it senses fundamental quantity being corrected (kVAR). Current and voltage sources available for general testing on feeder.	Most expensive control method. Directional (reversing direction of feed will reverse signal). Insensitive to abnormal voltage conditions. Requires current transformer and potential transformer.

5.6.6.2.1 Manual: The simplest means to accomplish capacitor bank switching is the manual control. Substation personnel, observing the need for capacitor banks to be switched, either go out to the yard and physically operate capacitor bank switching devices or operate them remotely from a panel.

5.6.6.2.2 Time Controls: Cooperatives wishing to relieve their personnel of the responsibility for manual capacitor bank control can substitute automatic controls. One of the most economical automatic controls is the time device. Time control switches the capacitor bank on or off at a fixed time each day. It usually takes the form of a clock that operates on station service ac. An electrical or mechanical carry-over device is required for each time clock to keep it running during temporary power outages. It may

include provisions for omitting control on weekends. Time control is most useful when the reactive load is periodic and predictable. This should be determined by examining the daily load curves. The time control does not require the monitoring of any electrical quantities.

Modern time clock controllers are microprocessor based, which provides 24-hour, 7-day programmable control. These devices typically use lithium batteries for backup during power outages.

5.6.6.2.3 Temperature Controls: In certain areas of the country, the reactive load is more closely aligned with temperature variation than with anything else. Such loads do not exhibit the periodicity that would suggest the use of time clocks. They are often associated with the operation of air conditioners. A temperature control can be used to apply shunt capacitors with increases or decreases in ambient temperature. The temperature controller's thermostat responds to changes in ambient temperature to provide input to the switching device. A determination of the relationship between kVAR load and air temperature is required to be able to set the temperature controller. As with time controls, these devices are relatively economical and do not require the monitoring of electrical quantities.

5.6.6.2.4 Voltage Controls: The most straightforward and simplest of the controls that respond to changes in electrical conditions is the voltage control.

The voltage found at a point on an electrical system is the summation of all conditions on the system. Capacitors increase the voltage at the point where they are applied. Thus, a low voltage would suggest the need for capacitors, and a high voltage would call for their removal. This would not be true at a location close to the output of a compensated regulator where high voltage is developed with peak loads. A simple capacitor control based only on voltage would not give the desired results if applied in a segment of the system where compensation in regulators cancelled the significance of high and low voltage as an indicator of loads. The bandwidth of the control should be larger than the voltage change caused by switching of the capacitor bank to prevent "hunting." Hunting refers to unintentional cycling of capacitor banks "on" and "off" due to incorrect settings on capacitor controllers.

Voltage controls usually respond to signals from a nominal 120-volt source ranging between 108 and 132 volts. If the switching device is a vacuum switch, the primary of the VT monitoring voltage should be protected by means of a distribution class surge arrester. This protects against high voltages produced by the chopping effect of the switches.

5.6.6.2.5 Current Controls: A simple answer to many of the desired objectives of capacitor control is the measurement and subsequent switching of the capacitors according to the flow of current. This type of controller is suitable where voltage is well regulated and the power factor of the load remains constant with variation in kilowatt loading, or if the power factor of the circuit varies predictably with variation in kilowatt loading.

This solution is particularly attractive on circuits consisting primarily of a known group of electric motors. Typical examples would be a circuit for pumps on a major water supply or for irrigation, driven by electric motors and located a considerable distance from the source, or on any application where there is a dependent relationship of reactive (kVAR) load with current.

Heavy loads on circuits of this type could occur at any time of day or night and any day of the week. Capacitors used on this application would be dedicated to serving these motor loads. Switching of the capacitors is, therefore, logically a function of these loads.

Current controls are sensitive to signals between 0.5 and 5 amperes from a 5-ampere CT secondary. As a safety feature to protect against high secondary open-circuit voltages, the control should be arranged to short circuit the CT secondary leads automatically when the control circuit is opened.

In some instances several banks of capacitors are placed in the same substation to facilitate incremental application of kVAR to the bus. There might be, for example, a fixed capacitor bank and two switched banks controlled by a two-step voltage controller. In addition to setting multi-step controls to avoid "hunting," the capacitor switches should be selected with the aim of protecting them from the consequences of back-to-back capacitor switching.

5.6.6.2.6 <u>VAR Controls</u>: The most sophisticated control method, the VAR control, responds directly to VAR demand. This type of controller is suitable where voltage is regulated and power factor varies unpredictably with variation in kilowatt loading.

Care has to be taken to set the control so that the response of the system to the presence or absence of the capacitor bank is less than the bandwidth represented by the maximums and minimums of the settings on the control. For example, if a 2100 kVAR bank of capacitors is applied, the "turn off" setting of the control should be greater than the "turn on" setting +2100 kVAR. This is necessary to prevent "hunting."

VAR controls are usually arranged to respond to signals from a VT with a secondary rating of 120 volts connected across two phases and a CT with a secondary rating of 5 amperes in the third phase. This arrangement provides a 90-degree phase angle between the voltage and the current signals at unity power factor.

Some VAR controls have capacitors in either the voltage or current inputs to retard the phase angle and thus make it possible to read VAR signals by monitoring fewer than three phases.

In addition to the above controls, there are a number of combination types, of which the most common are time and temperature, and voltage with current bias.

Modern capacitor controllers allow implementation of one or more of the above control functions to meet each project's unique requirements. The following functions are commonly used:

- Time and temperature
- Voltage with current bias
- Voltage with time bias

5.6.6.2.7 <u>Protective Controls</u>: Capacitor switching devices are also arranged to operate in response to signals from protective controls. These are described further under Section 5.6.7, "Protection."

5.6.6.3 Control Power

5.6.6.3.1 <u>Wiring</u>: Instruct the capacitor bank's manufacturer to provide a common junction box to facilitate field connections for all secondary circuits.

5.6.6.3.2 <u>Source</u>: Most controls with lockout relays require nominal 120 volts ac for operation, but they can be arranged for other voltages. The switches that are controlled, however, may be ac or dc at any number of voltages. Tell the capacitor bank's manufacturer the control voltages available at the installation.

5.6.6.3.3 <u>Transfer and Control Switches</u>: Many controls have selector switches for "automatic or manual" operation and for "local or remote" location. When the "local–remote" switch is set for "local" and the "automatic–manual" switch is set for "manual," the capacitor switching device may be controlled from the local control cabinet. If the "automatic–manual" switch is set for "automatic," the capacitor switching device will respond to automatic control signals from the bank's controller unless a protective override opens the device and locks it out.

5.6.7   **Protection**

Additional information on capacitor bank protection can be found in RUS Bulletin 1724D-112.

5.6.7.1 Fuses: Electric devices (or circuits) are generally fused for one or both of two basic reasons:

1. To protect the device from overloads
2. To protect the system from failure within the device

In some cases, such as group fusing with cutouts, the fuse may be used as a manual disconnect or switching means. This is not, however, a basic function of a capacitor fuse. Because capacitors, for economic reasons, are designed for operation at high dielectric stress, a certain calculated failure rate is to be expected. Thus, capacitor unit fuses are used primarily to protect the electrical system from dielectric failures that are expected to occur.

Conventional capacitor units are typically protected by an external fuse connected in series with each capacitor unit. Internally fused units are available that eliminate the need for external fuses. Internally fused capacitor units utilize fuse links connected in series with each of the unit's capacitor elements. An internally fused capacitor unit comprises a large number of capacitor elements connected in parallel with only a few groups of parallel elements connected in series.

Figure 5-19 illustrates capacitor units utilizing external and internally fused capacitor elements.

In general, capacitor banks utilizing internally fused capacitor units are configured with fewer capacitor units in parallel and more series groups compared to banks configured with external fuses.

Recent advances in capacitor bank design include the application of fuseless capacitor banks. This design utilizes capacitor units manufactured from polypropylene film. This technology provides a highly reliable design, virtually eliminating the need for fuses in many applications. These capacitor banks are simpler and more economical to build and operate compared to fused banks. The fuseless design has been mainly applied at voltages ranging from 69 kV to 230 kV.

5.6.7.1.1 <u>Functional Requirements of Capacitor Fuses</u>: Capacitor fuses have to accomplish the following principal functional requirements:

1. Isolate a faulted capacitor unit, bank, or portion of a bank from the circuit to which it is connected with negligible disturbance to the remainder of the bank or system.
2. Prevent case rupture by clearing the faulted capacitor from the circuit before the gas generated by the internal fault bursts the capacitor case, possibly damaging adjacent units or equipment, injuring personnel, or discharging dielectric liquid into the ecosystem.
3. Indicate the location of the failed capacitor (externally fused units only).

INTERNAL FUSES
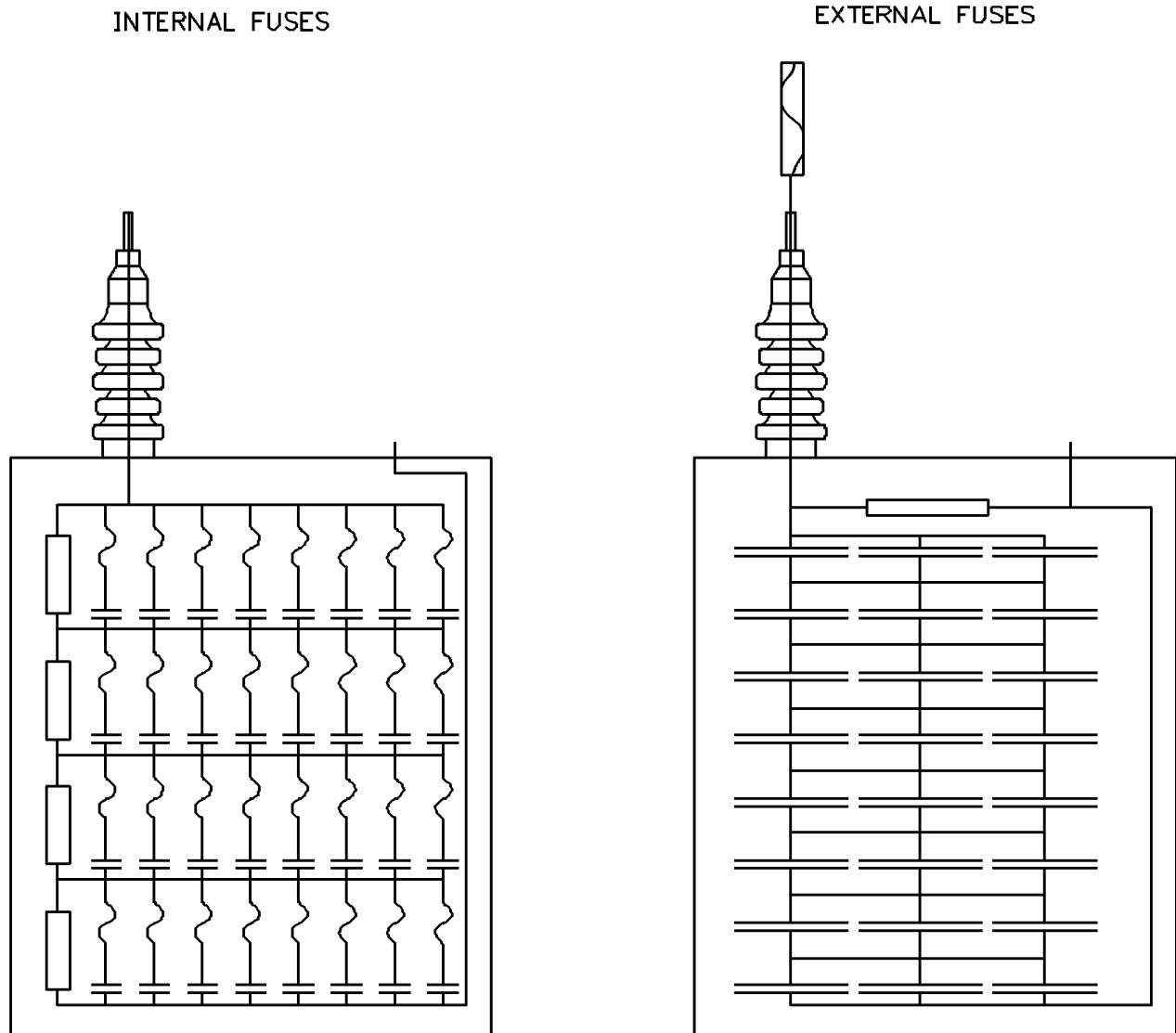
EXTERNAL FUSES

Figure 5-19: Typical Internally and Externally Fused Capacitor Units

4.   Carry normal capacitor overloads, transient inrush currents, discharge currents. and rated current without spurious operation and without affecting the ability of the fuse to perform the first three functions.

5.6.7.1.2 Types of Applications for Capacitor Fuses: There are two general schemes used for external fusing of capacitor banks: group fusing and individual fusing.

5.6.7.1.2.1   Group Fusing: Within the limits of the four required fuse functions, fuses may be applied to individual groups of paralleled capacitor units. Group fuses have to also be capable of interrupting the expected 60 Hz fault current. This type of fusing is not often used on substation capacitor banks.

Group fusing of capacitor banks may be advantageous for relatively small ungrounded-wye capacitor banks where operation of a group fuse isolates an entire phase without detrimental effect on the system. Elimination of the unit fuses permits more compact rack designs and simpler buswork.

However, care should be taken in the application of group fuses to be sure that fault current through the fuse will cause it to operate and clear before the combined system fault current and current discharge from adjacent capacitors into the faulted unit can cause case rupture. By providing adequate coordination between the fuses' "maximum total clearing" curve and the capacitor's case rupture curve, case rupture can be avoided.

5.6.7.1.2.2 Individual Fusing: In a capacitor bank or equipment having a number of units connected in parallel, each capacitor unit will usually have its own fuse. The series combination of each capacitor unit and fuse will be in parallel with other capacitors. Often, for multiphase arrangements and various series parallel groupings, backup bus fault protection is also provided by either circuit breakers or large power fuses.

With individual fusing, the loss of any individual capacitor does not necessarily result in the loss of the bank, the phase, or even the series section. Adjacent units discharge into the faulted unit and its fuse, allowing the fuse to quickly clear the fault.

Finally, if for any reason a reduction needs to be made in the kVAR of the bank, this can be accomplished easily by simply removing the appropriate fuses or links. The spare rack spaces then serve as a storage shelf for the extra capacitors.

5.6.7.1.3 Effect of Connections on Capacitor Fuses: The requirements for individual capacitor fuses are affected by the capacitor bank connections as well as the system to which the bank is connected. Non-current-limiting fuses, which are cheaper than the current-limiting type, can be used wherever bank connections can be arranged to limit the available fault current. Possible capacitor bank connections are the following:

5.6.7.1.3.1 Three-Phase Grounded Wye and Delta: Where only one series section of paralleled units per phase is used, and the equipment is connected three-phase grounded wye or delta, the unit fuse is subjected to the full available system short circuit whenever a capacitor unit fails. High-interrupting-capacity, current-limiting fuses are required in these situations when the fault current is on the order of 4000 amperes or higher.

5.6.7.1.3.2 Ungrounded Wye: When a three-phase wye connection is used with only one series section of paralleled units per phase and the neutral is left floating, the unfaulted phases will limit the current supplied to the faulted phase from the system. The fuse on the faulted unit will see a maximum of only three times normal bank phase current, and generally a less expensive low-interrupting-capacity fuse can be used. The small risk of simultaneous failure occurring in units of different phases that would result in a phase-to-phase fault is usually accepted.

The above applies to capacitor banks where single-bushing capacitor units have been mounted on insulated racks. However, capacitor units should be capable of interrupting system phase-to-ground fault current where two-bushing capacitor units are mounted on grounded racks. If lower rated fuses are used, fault clearing might not be accomplished by the fuse, which will require the bank's overcurrent relaying to operate a switching device capable of interrupting the fault current.

5.6.7.1.3.3   Series – Parallel: Series-connected groups of paralleled capacitor units can provide an effective means of limiting fault current to a level where less expensive non-current-limiting fuses can be used. This applies to installations where the parallel kVAR of individual groups does not exceed 4,650 kVAR.

The bank voltage rating is the principal factor that determines what series-parallel arrangement to use, along with the type of equipment. Multiple series section arrangements are not practical in equipment below 15 kV and in housed equipment. Consult the capacitor manufacturer regarding fusing for a given bank arrangement and specified maximum fault current.

5.6.7.2 Protective Controls: The purpose of a capacitor bank's protective control is to remove the bank from the bus before any units are exposed to more than 110 percent of their voltage rating. When capacitor units in a capacitor bank fail, the amount of increase in voltage across the remaining units depends on the connection of the bank, the number of series groups of capacitors per phase, the number of units in each series group, and the number of units removed from one series group. Protective controls are available for grounded neutral capacitor banks, ungrounded neutral capacitor banks, and capacitor banks connected wye-wye.

Where the capacitor bank is switched by a circuit breaker, the protective control does not need a lockout relay since breakers are usually equipped internally with lockout functions. However, where other switching means are provided, the protective control should have a lockout with a manual reset function.

5.6.7.2.1   Grounded Neutral: The most straightforward protective control for grounded neutral capacitor banks is the neutral relaying control. This scheme operates on the neutral current generated because of the unbalance caused by capacitor failures in any phase.

The major advantage of the neutral protection scheme is that it is relatively inexpensive. If there aren't too many series sections, this control can be set to alarm and trip at two different levels of neutral current to provide early detection that a problem exists in the bank and adequate protection should additional capacitor units fail. It is important to be aware of this protective control's disadvantages. Third-order harmonics have to be blocked out of the control, since they will flow in the neutral regardless of whether or not the bank is unbalanced. This blocking is often accomplished by means of a small capacitor in the control that tunes the sensitive element to 60 Hz.

It is noted that this control is not sensitive to overvoltages caused by the loss of equal number of capacitor units in one or more groups in each phase. However, this is usually not a significant limitation. It may be too sensitive and turn off the bank on unit failures occurring in different series sections of the same phase, even though no series group experiences greater than 110 percent overvoltage. Finally, since the associated CT has to be large enough to handle continuously the third-order harmonics (usually assumed to be 10 percent per phase of fundamental phase current, if no better information is available), the signal at the CT secondary may be too small for relays of ordinary sensitivity. This can be overcome by using three CTs, one in each phase, and connecting the secondaries in parallel and relaying for the zero sequence current.

This protective scheme responds only to capacitor overvoltages caused by unbalance and does not protect against capacitor overvoltage due to changes in three-phase supply voltage.

5.6.7.2.2   Ungrounded Neutral: The floating-neutral protective control is similar to that for the grounded neutral bank, except that a VT is used in the neutral (usually rated 15 kV) to indicate neutral

voltage shift on loss of units. The control is voltage sensitive and subject to the same limitations and advantages as the protective control for grounded neutral capacitor banks.

5.6.7.2.3 Wye-Wye: The wye-wye capacitor bank may be protected by means of a CT between the two ungrounded neutrals. Care should be taken to avoid exceeding individual capacitor unit fuses' interrupting ratings when applying wye-wye banks having one series group per phase. Dependent on the number of capacitors in each phase, there may be sufficient discharge current from parallel capacitor units into the faulted unit to exceed its fuses' interrupting rating. The impedance of the neutral CT is negligible; however, it cannot limit discharge currents into the faulted unit. This scheme tends to be fairly sensitive, and the CT does not require gap protection, even if a vacuum switch is used. The buswork, however, can be difficult to design.

5.6.7.3 Protection of Current and Voltage Transformers Installed in Capacitor Banks

5.6.7.3.1 Current Transformers: Switching of capacitors produces transient currents that can produce overvoltages on secondary circuits. Overvoltage protection is required to prevent damage to the current transformer winding and connected burdens. Secondary protection generally involves the correct application of a high-current-rated varistor or spark gap connected directly across the current transformer terminals. Varistors applied to secondary windings should be selected with sufficient energy-absorbing capability to withstand secondary oscillations. Additionally, current transformers that have wound primary windings require overvoltage protection by adding an arc gap or arrester across the primary.

5.6.7.3.2 Voltage Transformers, Capacitor-Coupled Voltage Transformers, and Resistance Potential Devices: AC voltage sources of various types are used in capacitor bank applications for control and protection schemes. Overvoltage protection of these devices is normally required since transients or surges produced during switching can overstress primary-to-secondary insulation and secondary-to-ground insulation. Surge arresters are typically used for primary protection. Varistors or spark gaps are typically used for secondary protection.

AC voltage sources should be specified for full line voltage with primary overvoltage protection added to provide additional protection.

5.6.7.4 Bus Insulation Systems: Unlike enclosed capacitor banks, open-rack capacitor banks have exposed live parts. In some cases, this exposure has resulted in bank outages due to isolation of faults originated by birds or animals bridging live parts or live parts to ground. One straightforward prevention of this is to use edge-mounted equipment, since the electrical clearances in the racks used in this equipment are sufficiently liberal and make it highly unlikely that any bird or animal will be large enough to bridge any of the live parts.

However, if upright racks are used and birdproofing is deemed necessary, bus bar insulation systems are commercially available that can be used to protect against accidental bridging of conductors commonly caused by birds and animals. Heat shrinkable tubes, tapes, and sheets and molded fittings allow for simple installation and flexibility to cover most conductor shapes and sizes. Although enclosed capacitor banks have very little exposure to faults by rodents, bus bar insulation systems are sometimes applied in areas where animals such as snakes and lizards are prevalent. For a description of these protective devices, see CRN's *Animal-Caused Outages* (Project 94-5).

Capacitor bank manufacturers can apply bus insulation at the factory, or it can be applied in the field.

5.6.7.5 Lightning: Lightning surges and the switching of capacitors can result in significant overvoltages. Generally, capacitor banks installed in a substation will be protected from lightning and switching surges by the same devices that protect the substation. However, in regions where lightning activity is high, or in applications involving frequent switching of a capacitor bank, it may be appropriate to install surge arresters at the capacitor bank to limit transient overvoltages.

Coordinate insulation levels of installed equipment—substation and shunt capacitor bank—for effective lightning and switching surge protection.

5.6.7.6 Corona: For systems with voltages above 100 kV, consult the capacitor manufacturer about the advisability of providing corona shields.

5.6.8   Grounding and Short-Circuiting of Capacitor Banks

In accordance with NEMA Std. CP-1, substation capacitor units are built with internal discharge resistors so that the residual voltage is reduced to 50 volts or less within 5 minutes after the capacitor unit has been disconnected from its source of supply.

Manually operated switches should be provided to short-circuit and ground each series section of the capacitor bank after it has been disconnected from the circuit but before it is handled by personnel to avoid potentially exposing personnel to hazardous voltages at capacitor terminals.

The duty on these switches is not severe, and most bank manufacturers can supply single hook-stick-operated switches for open-rack bank designs and gang-operated switches for enclosed capacitor bank designs to perform both the shorting and grounding functions. While not always required, it may be desirable to specify interlock schemes to prevent the operation of shorting and grounding switches on live circuits and to keep personnel from access to capacitor bank live components when the banks have not been shorted and grounded.

5.6.9   Mounting

There are two common positions for mounting capacitor units in outdoor substation racks: upright and edge mount. These mounting configurations are illustrated in Figures 5-20 and 5-21.

5.6.9.1 Open Rack Design: The upright mounting position is generally preferred for capacitor units up to 10 kV and edge mount for units above 10 kV. Upright racks are relatively compact and provide a metal framework on the outside, which tends to protect the capacitor units. Edge-mount units provide ample clearances and protection from bus and bushing flashovers caused by birds, rodents, and other causes. They do, however, require more physical ground space.

In the United States, power capacitors are mounted by means of two flanges spaced 39.7 cm (15-5/8 in.) apart.

Where units are protected by means of expulsion fuses, it is necessary to provide a minimum of 3 feet of air clearance plus strike distance between the ends of the fuses and any grounded metal objects to prevent inadvertent flashovers on fuse operation caused by ionized gases contacting the metal objects. For non-expulsion fuses, the additional 3 feet of clearance is unnecessary.

Normally, capacitor equipment and its substructures are designed to withstand minor earthquake

DIMENSIONS FOR MULTI-UNIT RACKS USING SINGLE-PHASE CAPACITORS

15 5/8"

36"
±1/16"

A*

FOUR 3/4" HOLES
ON 5" BOLT CIRCLE
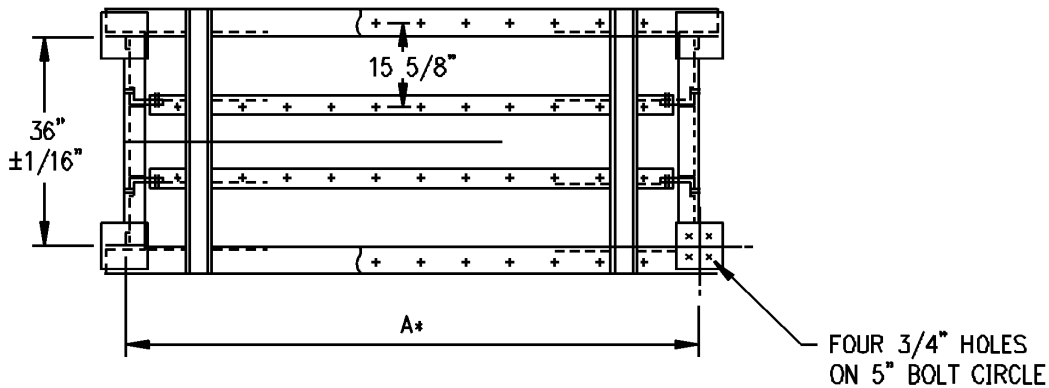
* DEPENDENT UPON BUS CONNECTION
AND NUMBER OF UNITS.

MINIMUM SPACING BETWEEN ℄ AND ℄ OF CAPACITOR UNITS
8"-2400-7960 VOLTS   9"-8320-14400 VOLTS

60" TYPICAL
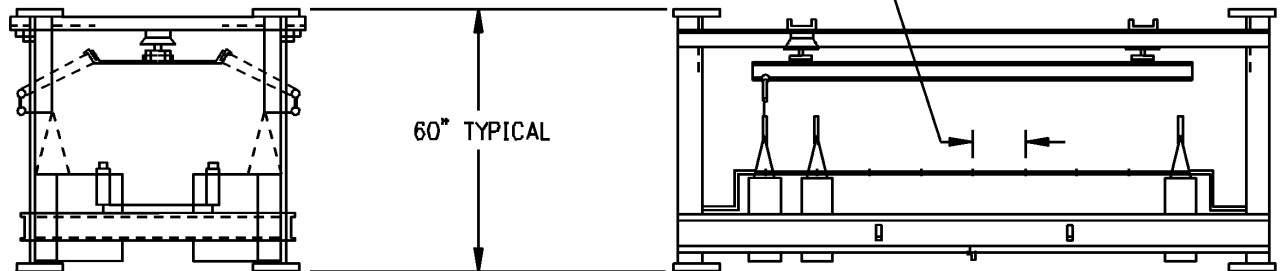
ALL DIMENSIONS IN INCHES

DETAILS OF CONSTRUCTION ARE
OPTIONAL.

Figure 5-20: Capacitors Vertically Mounted. Ref. NEMA Std. CP-1, FIG. 4-1. Reproduced with
permission of the National Electrical Manufacturers Association.

conditions, 129 km/h (80 mph) wind, and 1.27 cm (0.5 in.) of ice (non-simultaneously). Where
conditions are more severe than this, the capacitor manufacturer should be told.

Capacitor racks and housings have provisions for mounting of up to three tiers, with no more than two
rows of units per tier. There should be unrestricted air circulation around the units. If ambient conditions
are extremely dusty, smoky, or salty, consult the capacitor manufacturer as to the advisability of extra
creep bushings and insulators and more generous strike clearances between live parts.
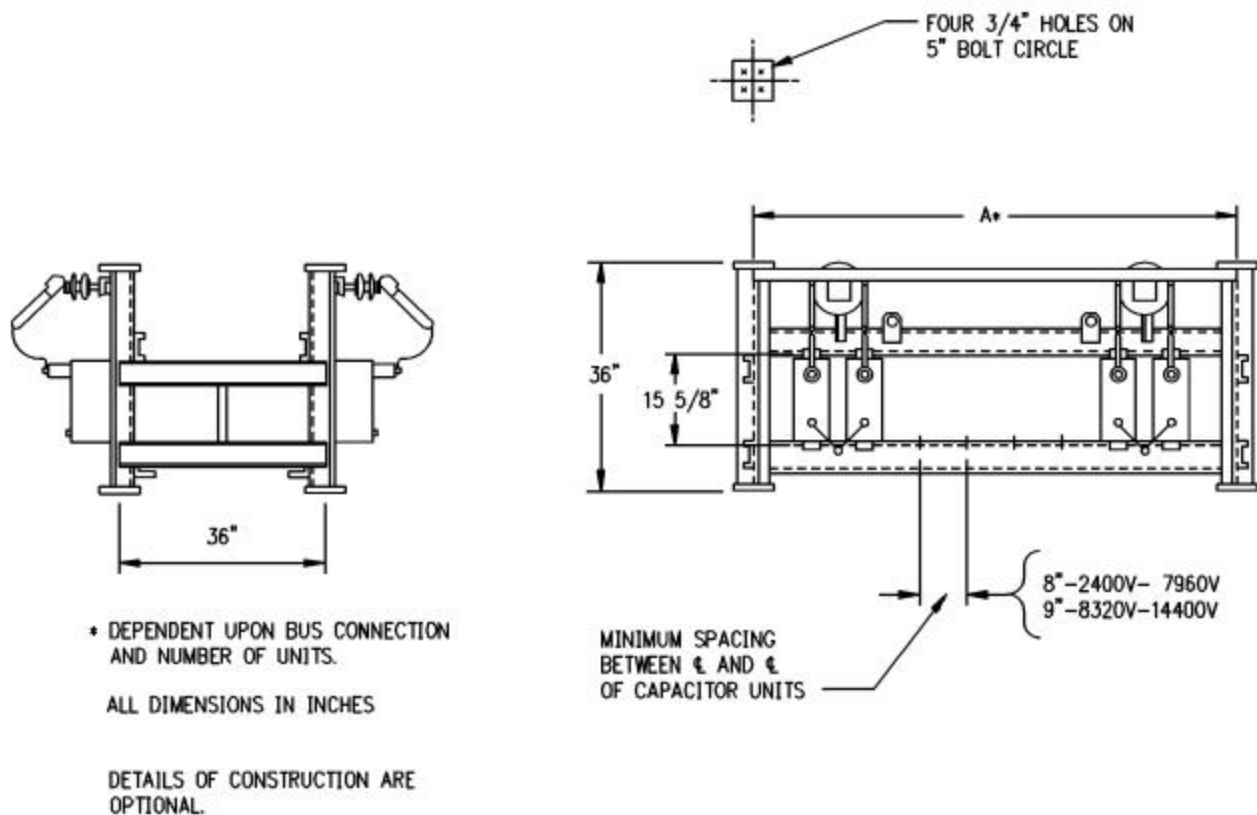
Figure 5-21: Capacitors Horizontally Mounted. Ref. NEMA Std. CP-1, FIG. 4-2. Reproduced with permission of the National Electrical Manufacturers Association.

Capacitor equipment is often mounted on 2.44-meter (8-foot) substructures to provide adequate ground clearance, personnel safety, ventilation, and a place to mount accessories. This clearance should be carefully checked and increased if necessary to meet applicable safety codes.

5.6.9.2 Enclosed Bank Design: Manufacturers of enclosed capacitor banks custom design each bank for its unique application. Efforts are made by the manufacturer to provide a compact design. The overall size of the enclosure depends on the number of installed components and orientation and mounting of these components. The designer may mount individual capacitor units horizontally or vertically to reduce the overall size of the bank.

Non-expulsion, capacitor-rated, current-limiting fuses are used rather than expulsion type to fuse externally fused capacitor units. Expulsion fuses are not to be used since they do not support a compact bank design. These fuses require clearances for fuse expulsion in addition to electrical clearances. Internally fused capacitor units are often used since no external fuses are required and they allow for a more compact design.

5.6.10 <u>Factory Tests</u>

In the United States, shunt power capacitors are usually tested in accordance with NEMA Std. CP1, which includes production and design tests.

5.6.11 <u>Inspection and Maintenance</u>

IEEE Std. 1036 provides guidelines for inspection, maintenance, and field testing of shunt capacitor banks.

5.6.12 <u>Typical Technical Specification</u>

5.6.12.1 General

5.6.12.1.1 <u>Scope</u>: This specification covers the manufacture of (1) _____ kVAR, _____ kV, 60 Hz, 3-phase (indoor) (outdoor) (open-rack) (metal-enclosed) shunt capacitor bank assembly, connected (ungrounded wye) (delta) (grounded wye) (double wye). Each capacitor bank shall comprise _____ individual _____ kVAR, single-phase, _____ kV, (single) (double) bushing, _____ kV BIL capacitors. There shall be _____ capacitors individually connected in parallel per phase and _____ series groups.

The manufacturer shall guarantee in writing that each capacitor bank meets the requirements of _____ and other applicable American standards in all respects. These include the most recent version of all applicable codes and standards, including, but not limited to, those of the following: American National Standards Institute, *National Electrical Code*, *National Electrical Safety Code*, American Society for Testing and Materials, and American Society of Civil Engineers.

The capacitor units shall be mounted in (upright) (edge-mount) racks that shall be (fully equipped) (partly equipped) and arranged for a maximum of _____ units each.

_____ banks of capacitors, each rated _____ kVAR, will ultimately operate in parallel on the same bus (and will be separately switched). The banks will be separated by approximately _____ feet of bus, anticipated to have a maximum inductance of _____ microhenries. The manufacturer shall make suitable provision to limit the inrush currents due to back-to-back capacitor switching to the capabilities of the switches and fuses. A bus reactor would be the user's responsibility.

5.6.12.2 **Controls:** Each capacitor bank assembly shall (not) be equipped with (neutral unbalance detection – grounded and ungrounded wye systems) (unbalance detection – delta systems).

Each capacitor bank shall be equipped with a (voltage) (current) (VAR) (current-compensated voltage) (time) (temperature) (other) control. *(Cross out if not applicable.)*

The secondary control voltage available at the substation will be volts, _____ (VAC) (VDC).

<u>Enclosure (Metal-Enclosed Only)</u>
The manufacturer shall furnish an enclosure rated for (indoor) (outdoor) installation of (dead front) (live front) construction to house capacitor bank components. The enclosure shall be constructed in accordance with the latest applicable industry standards and governing local and *National Electrical Code* requirements. The enclosure shall be constructed of not less than _____ U.S. gauge A-60 "galvaneel" steel.

The manufacturer shall clearly identify bus phase sequence in the cable entrance section in conformance with IEEE Std. C37.20.2. Tying bars for support of cables shall be provided. Cable terminals, NEMA Type _____ , shall be provided in sufficient quantity to terminate _____ cables per phase.

The enclosure shall be provided complete with access doors, lifting provisions, ventilation, heaters, signage, and nameplate.

Elevating Substructure(s) (Open Rack Only)
The manufacturer shall (not) furnish substructures that will elevate the capacitor racks a minimum of (2.44) (_____) meters (8) (_____) feet above the ground.

Surge Arresters
The manufacturer shall provide (distribution) (intermediate) (station) class surge arresters with a maximum continuous operating voltage of _____ kV.

Switching Devices
The capacitor bank shall be furnished with the following switching devices:

_____ Capacitor Switch(es) – (single-pole, vacuum switches) (three-pole, vacuum switches) (single-pole, oil switches) (vacuum circuit breaker) (circuit switcher), __ kV, __ kV BIL, __ amp, kA – Asymmetrical Momentary, __ kA – Symmetrical Interrupting

_____ Main Disconnect Switch(es) – three-pole, group-operated, non-load-break disconnect switch, _____kV, __ kV BIL, __ amp, kA – Asymmetrical Momentary

_____ Shorting Switches – (single-) (three-) pole, (group-operated), non-load-break disconnect switch, _____kV, __ kV BIL, __ amp, __ kA – Asymmetrical Momentary

_____ Grounding Switch(es) – Ground switch with fully insulated, manually operated handle to ensure that all stored energy has been discharged from capacitors while providing safety and visual ground indication. Rated __ kV, __ kV BIL, __ amp, __ kA – Asymmetrical Momentary

In-Rush Current Limiting Reactors
If required, the manufacturer shall provide single-phase inrush current-limiting reactors to limit inrush current due to bank energization or back-to-back capacitor switching to the capabilities of switches and fuses.

Key Interlocking Scheme
The manufacturer shall provide all key interlocking hardware to implement a key interlocking scheme designed by the manufacturer to prevent entry by personnel into any live portions of the shunt capacitor bank until the bank has been de-energized for at least 5 minutes and grounding and shorting switches have been closed.

Main Fusing
The manufacturer shall (not) provide (current-limiting) power fuses to isolate fault conditions within the shunt capacitor bank.

Capacitor Unit Fusing
The manufacturer shall provide (internally) (externally) fused capacitors. (For externally fused capacitors, each capacitor shall be individually fused to protect against case rupture with a current-

limiting fuse. Each fuse shall be non-expulsion, capacitor-rated, current limiting, with blown fuse indication. Fuse size shall be determined by the manufacturer to ensure protection against case rupture.)

5.6.12.3 Accessories: Base and stack insulators shall be high strength (cap and pin) (station post) and shall be colored (ANSI #70 gray) (brown).

The manufacturer shall furnish all necessary racks, shelves, superstructures, buswork, insulators, connections, terminals, and hardware. If aluminum connections are involved, a container of oxide inhibitor shall be furnished. A can of touch-up paint of the same color as the capacitors shall be furnished.

Any necessary instrument transformers for proper operation of the controls shall be furnished. They shall be suitably protected by means of arresters, protector tubes, or gaps, as required.

5.6.12.4 Submittals: The manufacturer shall supply suitable drawings (for approval) (for installation) (for record) as follows:

   a.   Outline drawings complete with elevations, section views, and base details
   b.   Auxiliary equipment outlines
   c.   Three-line diagram
   d.   Control schematics and wiring diagrams
   e.   Interconnection diagram
   f.   Bill of material
   g.   Hardware schedule
   h.   Base plan

The manufacturer shall also furnish _____ copies of pertinent

   a.   Instruction books
   b.   Spare parts lists
   c.   Maintenance manuals
   d.   Fuse curves (minimum melt and maximum total clearing)
   e.   Capacitor case bursting curves
   f.   Test reports
   g.   Manufacturer's catalog data sheets

5.6.12.5 Information To Be Furnished with Proposal: Each proposal submitted to furnish the capacitor banks covered by this specification shall include, in addition to the quoted price and promised delivery, the following information in the form and sequence indicated:

5.6.12.5.1 Drawings and Descriptive Data:
   A.   Outline and arrangement drawings for each bank section including overall dimensions, weights, and breakdowns and weights for shipment
   B.   Required locations for owner's mounting bolts and channel
   C.   Catalog cut sheets and other data describing the equipment proposed

5.6.12.5.2 Ratings and Performance: Shunt capacitor bank components are capable of meeting the following ratings and performance under the altitude and conditions specified:

A. Cable Entrance (Describe):

    _____
    _____
    _____

B. Main Bus:

    1. Continuous Current Rating   _____A

    2. Withstand Capability   _____kA-rms-Sym

    3. Bus Support Type and Cantilever   _____

    4. Bus Material and Insulation   _____

C. Ground Bus:

    1. Description

        _____
        _____

    2. Continuous Current Rating   _____A

D. Surge Arresters:

    1. Manufacturer   _____

    2. Style No.   _____

    3. Type   _____

    4. Class   _____

    5. MCOV   _____kV

E. Disconnect Switches:

    1. Manufacturer   _____

    2. Style No.   _____

    3. Rated Maximum System Voltage   _____kV

    4. Basic Impulse Level   _____kV

    5. Low-Frequency Withstand Voltage   _____kV

    6. Rated Continuous Current   _____A

7.   Momentary Rating   _____kA-rms-Asym.

8.   No. of Auxiliary Contacts   _____

F. Main Fusing:

1.   Manufacturer   _____

2.   Style No.   _____

3.   Rated Maximum Voltage   _____kV

4.   Basic Impulse Level   _____kV

5.   Rated Continuous Current   _____A

6.   Interrupting Rating   _____kA-rms-Sym.

7.   Current Peak Let-Thru
     @ Interrupting Rating   _____A-Peak

G. Current-Limiting Reactors:

1.   Manufacturer   _____

2.   Type   _____

3.   Rated Maximum System Voltage   _____kV

4.   Basic Impulse Level   _____kV

5.   Continuous Current   _____A

6.   Rated kVA   _____kVA

7.   System Frequency   _____Hz

8.   Inductance   _____μH

9.   Q-Factor   _____

10. Tolerance   _____

11. Cooling Method   _____

H. Capacitive Switching Device:

1.   Manufacturer   _____

2. Type   _____

3. Rated Maximum System Voltage   _____kV

4. Basic Impulse Level   _____kV

5. Rated Continuous Current   _____A

6. Close and Latch Capability   _____kA-rms-Asym.

7. Interrupting Capability   _____kA-rms-Sym.

8. Control Option   _____

9. Operating Mechanism

    a.   Control Voltage   _____

    b.   Mechanism Type   _____

    c.   Close Time   _____

    d.   Trip Time   _____

    e.   No. of Auxiliary Contacts   _____

    f.   Accessories   _____

I.   Capacitor Units:

1. Manufacturer   _____

2. No. of Installed Units per Bank   _____

3. No. of Spare Units per Bank   _____

4. Case Material   _____

5. Fusing Type (Internal) (External)   _____

6. Bushing Configuration   _____

7. Rated Maximum System Voltage   _____kV

8. Basic Impulse Level   _____kV

J.   Ground Switch:

1. Manufacturer   _____

2. Rated Continuous Current   _____A

3. Momentary Rating   _____kA-rms-Sym.

K. Key Interlock System:

1. Manufacturer   _____

2. Description

    _____

    _____

    _____

L. Auxiliary Power Transformer:

1. Manufacturer   _____

2. Style No.   _____

3. Rated kVA   _____ kVA

4. Connection   _____

5. Rated Maximum System Voltage   _____ kV

6. Basic Impulse Level:

    a.   Primary   _____kV

    b.   Secondary   _____kV

7. Fusing - Primary:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Rated Maximum System Voltage   _____kV

    d.   Maximum Sym. Interrupting Capability   _____kA-rms-Sym.

8. Fusing - Secondary:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Rated Maximum System Voltage   _____V

    d.   Maximum Sym. Interrupting Capability   _____kA-rms-Sym.

9. Surge Protection:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Energy Discharge Capability   _____Joules

M.   Instrument Transformer - Current:

1. Phase Unbalance Relay Current Transformer:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Accuracy Class   _____

    d.   Ratio   _____

2. Line Metering Current Transformer:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Accuracy Class   _____

    d.   Ratio   _____

3. Surge Protection – Line Metering Current Transformer:

    a.   Manufacturer   _____

    b.   Style No.   _____

    c.   Energy Discharge Capability   _____Joules

N.   Controller - Combined Control and Relaying Packages:

1. Manufacturer   _____

2. Style No.   _____

3. Control Description

    _____
    _____
    _____

4. Protective Functions

_____
_____
_____

5. Accessories

_____
_____
_____

O. Test Switches:

1. Manufacturer   _____

2. Style No.   _____

P. Terminal Blocks:

1. Manufacturer   _____

2. Style Nos.   _____

Q. Auxiliary Heating, Ventilation, Power, and Lighting (Metal-Enclosed Only):

1. Heating - Description

_____
_____
_____

2. Ventilation - Description

_____
_____
_____

3. Auxiliary - Power and Lighting - Description

_____
_____
_____

R. Equipment Testing Included:

_____
_____
_____

5.6.12.5.3 List of Recommended Spare Parts: Seller shall provide list of recommended spare parts, quantity, and unit price.

5.6.13 References

Anderson Electric Corporation, *Technical Data – A Reference for the Electrical Power Industry*, Leeds, Alabama, p.164.

ANSI Publication C107.1, "Guidelines for Handling and Disposal of Capacitor and Transformer Grade Askerels Containing Polychlorinated Biphenyls."

ANSI Std. C37.06, "Preferred Ratings and Related Required Capabilities for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI/IEEE Std. C37.04, "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on Symmetrical Current Basis."

ANSI/IEEE Std. C37.012, "IEEE Application Guide for Capacitance Current Switching for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI/IEEE Std. C37.99, "Guide for the Protection of Shunt Capacitor Banks."

Dow Chemical Company, "Dow XFS-4769L Capacitor Fluid," December 2, 1975.

Dow Chemical Company, "Environmental Impact Statement, Dow XFS-41G9L Capacitor Fluid," Midland, Michigan.

Dow Corning Corporation, "Dielectric Properties of Dow Corning Silicone Fluids," 1975.

Dow Corning Corporation, "Dow Corning Dielectric Liquids for Power Transformers," 1975.

Duckett, D.A. (Chief Product Engineer, RTE Corporation), "Environmentally Acceptable Insulating Fluids May Replace Askerel," Presentation to General Meeting of Edison Electric Institute, Transmission and Distribution Committee, Minneapolis, Minnesota, May 8, 1975.

IEEE Std. 76, "IEEE Guide for Acceptance and Maintenance of Transformer Askerel in Equipment."

IEEE Std. 519, "Recommended Practices and Requirements for Harmonic Control in Electrical Systems."

IEEE Std. 1036, "Guide for Application of Shunt Power Capacitors."

IEEE Std. C37.20.2, "Standard for Metal-Clad and Station Type Cubicle Switchgear."

IEEE Std. C57.16, "IEEE Standard Requirements, Terminology, and Test Code for Dry-Type Air-Core Series-Connected Reactors."

Jordan, William III, "Electrical/Insulating Materials," *Engineering Materials Handbook*. New York: McGraw Hill Book Company, 1958.

Lindstrom, C.O., "Series and Shunt Capacitor Banks; Provision for Collection of PCB Leakage," Memo EKT1-COL/BJ, Swedish State Power Board, August 15, 1974.

McGraw-Edison Company, "An Environmentally Acceptable Liquid Dielectric for Power Capacitors," Bulletin 76015, March 1976.

Murch, R.H. "New Capacitor Impregnants," St. Louis, Mo.: Monsanto Industrial Chemicals Company.

National Rural Electric Cooperative Association, Cooperative Research Network, *Animal-Caused Outages.* Project 94-5. Arlington, Va.: NRECA, 1996.

NEMA Std. CP-1, "Shunt Capacitors."

Pratt, R.A., W.W. Olive Jr., B.D. Whitman, and R.W. Brown, "Capacitor Case Rupture Withstand Capability and Fuse Protection Considerations," Presentation to Edison Electric Institute, Transmission and Distribution Subcommittee, May 5-6, 1977.

RUS Bulletin 1724D-112, "The Application of Shunt Capacitors to the Rural Electric System."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

Sangamo Electric Company, Power Capacitor Application, Measurement and Control (papers), Workshop Seminar, Springfield, Illinois, November 6-8, 1962.

U.S. Department of Commerce, National Information Service, "An Appraisal of Tests and Standards for the Evaluation of Electrical Insulating Fluids." PB-253 110 (ERDA), May 14, 1976.

U.S. Department of Commerce, National Technical Information Service, "Polychlorinated Biphenyls and the Environment," Report No. ITF-PCB-72-1, Interdepartmental Task Force on PCB's, Com.-72-10419, Springfield, Va.: Dept. of Commerce.

5.7 AIR SWITCHES

5.7.1 General

This section deals with high-voltage air switches used in substations. Items discussed include applicable national standards, types of air switches, various constructions of outdoor air switches, service conditions, ratings, and tests.

The general function of an air switch is as stated in ANSI/IEEE Std. C37.100: "A switching device designed to close and open one or more electrical circuits by means of guided separable contacts that separate in air." Air, at atmospheric pressure, is also the insulating medium between contacts in the open position.

Many varieties of air switches have been developed to fulfill special user requirements. RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers," contains both fully accepted and conditionally accepted types of air switches and should be consulted whenever air switches are required.

All varieties of air switches used in a cooperative's substations need to generally conform to all applicable national standards and guides. The principal standards and guides for air switches are the following:

- ANSI Std. C29.1, "Test Methods for Electrical Power Insulators"
- ANSI Std. C29.8, "Wet-Process Porcelain Insulators (Apparatus, Cap and Pin Type)"
- ANSI Std. C29.9, "Wet-Process Porcelain Insulators (Apparatus, Post Type)"
- ANSI Std. C29.10, "Wet-Process Porcelain Insulators (Indoor Apparatus Type)"
- ANSI Std. C37.32, "Standard for Switchgear—High-Voltage Air Switches, Bus Supports, and Switch Accessories—Schedules of Preferred Ratings, Manufacturing Specifications and Application Guide"
- ANSI/IEEE Std. C37.100, "IEEE Standard Definitions for Power Switchgear"
- IEEE Std. C37.34, "Test Code for High-Voltage Air Switches"
- IEEE Std. C37.35, "Guide for the Application, Installation, Operation and Maintenance of High-Voltage Air Disconnecting and Load-Interrupter Switches"
- NEMA Std. SG-6, "Power Switching Equipment"

5.7.2 Types of Air Switches

The main types of air switches are determined by and named according to their application. Standard definitions, according to ANSI/IEEE Std. C37.100, describe their general functions.

5.7.2.1 Disconnecting or Isolating Switch (Disconnector, Isolator): "A mechanical switching device used for changing the connections in a circuit, or for isolating a circuit or equipment from the source of power." This switch "is required to carry normal load current continuously and, also, abnormal or short-circuit currents for short intervals as specified. It is also required to open or close circuits either when negligible current is broken or made, or when no significant change in the voltage across the terminals of each of the switch poles occurs."

5.7.2.1.1 Typical Applications:

a. Circuit breaker isolation
b. Power transformer isolation
c. Voltage transformer disconnecting
d. Equipment bypassing
e. Bus sectionalizing

NOTE: Where the current to be broken or made is not negligible, a horn-gap switch (see Section 5.7.2.3) should be used.

5.7.2.2 Grounding Switch: "A mechanical switching device by means of which a circuit or piece of apparatus may be electrically connected to ground." Grounding switches are often mounted on the jaw or hinge end of disconnecting or horn-gap switches. See Figure 5-22.

5.7.2.2.1 Typical Applications:

a. To ground buses or circuits (for safe maintenance) after they are first isolated
b. To intentionally ground a circuit (using an automatic high-speed device) in order to activate a remote protective relaying scheme

5.7.2.3 Horn-Gap Switch: "A switch provided with arcing horns." See Figure 5-23.

Figure 5-22: Horizontally Mounted Double Break Switch with Grounding Switch.
Courtesy of Tuley & Associates, Inc.

Figure 5-23: Horizontally Mounted Double-Break Switch. Note arcing horns and corona shields at blade
contact points. Courtesy of Tuley & Associates, Inc.

5.7.2.3.1 <u>Typical Application</u>: To de-energize or energize a circuit that possesses some limited amount of magnetic or capacitive energy, such as transformer exciting current or line charging current. The arcing horns protect the main contacts during opening or closing and enhance the ability of the switch to perform its task.

NOTE: Where the amount of current to be broken or made is not clearly within the switch's capability, consult the manufacturer or use an interrupter switch (see Section 5.7.2.4).

5.7.2.4 Interrupter Switch: "An air switch, equipped with an interrupter, for making or breaking specified currents, or both." "The nature of the current made or broken, or both, may be indicated by suitable prefix, that is, load interrupter switch, fault interrupter switch, capacitor current interrupter switch, etc." Typical applications are indicated by the above-named prefixes. See Figure 5-24.

Figure 5-24: Horizontally Mounted Vertical-Break Interrupter Switch.
Courtesy of Tuley & Associates, Inc.

5.7.2.5 Selector Switch: "One arranged to permit connecting a conductor to any one of a number of other conductors." In substation applications, it is unlikely that more than two conductors would be subject to selection.

5.7.2.5.1 <u>Typical Applications</u>:

    a.   To connect a potential device to either of two buses
    b.   To perform a joint disconnecting and grounding function

5.7.3 <u>Various Constructions of Outdoor Air Switches</u>

Outdoor air switches are constructed in many different styles or construction classifications. Preferred standard ratings are listed in Tables 5-38, 5-39, and 5-40. A pictorial representation of each classification is shown at the bottom of Table 5-39. The various constructions are described below and include ANSI/IEEE Std. C37.100 definitions (in quotation marks) where appropriate.

Table 5-38: Preferred Voltage Ratings for Station Class Outdoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 1. Reproduced with permission of the National Electrical Manufacturers Association.

Line Number	Rated Maximum Voltage kV rms	Rated Withstand Voltage			Corona and Radio Influences Test Voltages	
		Lightning Impulse[1] kV peak	Power Frequency kV rms		Test[2] Voltage kV rms	Limit of RIV[3] mV @ 1 MHz
			Dry 1 Minute	Wet 10 Seconds		
	(1)	(2)	(3)	(4)	(5)	(6)
1	8.25	95	35	30	—	—
2	15.5	110	50	45	—	—
3	25.8	150	70	60	—	—
4	38.0	200	95	80	—	—
5	48.3	250	120	100	—	—
6	72.5	250	120	100	—	—
7	72.5	**350**[4]	175	145	—	—
8	121	350	175	145	77	500
9	121	450	235	190	77	500
10	121	**550**[4]	280	230	77	500
11	145	350	175	145	92	500
12	145	450	235	190	92	500
13	145	550	280	230	92	500
14	145	**650**[4]	335	275	92	500
15	169	450	235	190	107	500
16	169	550	280	230	107	500
17	169	650	335	275	107	500
18	169	**750**[4]	385	315	107	500
19	242[5)]	550	280	230	154	500
20	242[5)]	650	335	275	154	500
21	242[5)]	750	385	315	154	500
22	242[5)]	**900**[4]	465	385	154	500
23	242[5)]	1050	545	455	154	500
24	362	1050	545	455	230	500
25	362	**1300**[4]	610	525	230	500
26	550	1550	710	620	349	500
27	550	**1800**[4]	810	710	349	500
28	800	2050	940	830	508	750

NOTES:
[1] For switches rated 362 kV and higher, see table 2 [Table 5-39] for values of rated switching impulse withstand voltages.
[2] The test voltages are 110% of the rated maximum line-to-neutral voltage. It is not necessary to retest switches previously tested and acceptable at 105%.
[3] If equipment of any given rated maximum voltage is used on a circuit of a higher voltage rating, the radio influence voltage limit and test voltage for the equipment shall be that corresponding to the rated maximum voltage of the circuit.
[4] Modern arrester technology enables use of lower lightning impulse rated equipment in some applications. The traditional values are shown in bold font.
[5)]The switches listed in lines 19 through 28 are intended for application on systems effectively grounded as defined in ANSI/ IEEE Std. 142.

Table 5-39: Preferred Switching Impulse Withstand Voltage for Station Class
Outdoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 2.
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Line Number (from table 1 [Table 5-38])	Rated Maximum Voltage kV rms	Rated Lightning Impulse kV Peak	Switching Impulse Withstand Voltage kV Peak	
			To Ground[1]	Across Open Gap[2]
(1)	(2)	(3)	(4)	
24	362	1050	750	655 + (295)
25	362	1300	885	825 + (295)
26	550	1550	1050	880 + (450)
27	550	1800	1150	1000 + (450)
28	800	2050	1300	1000 + (650)

NOTES:

[1] Line-to-ground insulation strength is based upon 97.7 percent probability of withstand where the standard deviation is 6 percent. See ANSI Std. C37.34, 4.4.7.

[2] Values in parenthesis are 60 Hz bias voltages expressed in kV_p units (column 1 voltage * $\sqrt{2}/\sqrt{3}$).

The summation of this opposite polarity bias voltage and the associated open gap switching impulse voltage is equal to a 97.7 percent probability of line-to-ground flashover (CFO + 2). See C37.34, 4.4.8.

CONSTRUCTION CLASSIFICATIONS
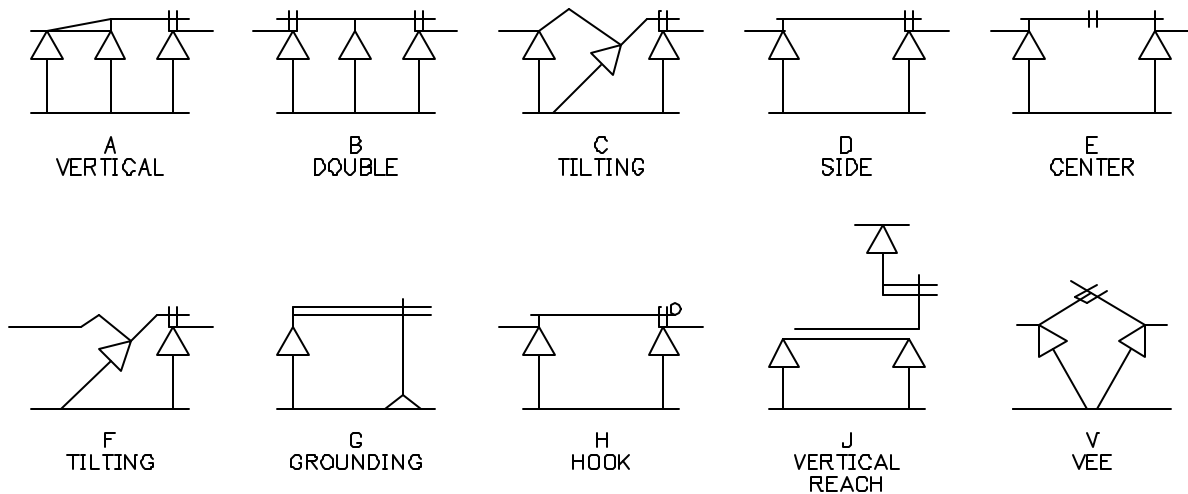
Ref. ANSI Std. C37.32 – 1996, Figure B–1. Reproduced with permission of the National Electrical Manufacturers Association.

Table 5-40: Preferred Continuous and Withstand Currents for Station Class
Outdoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 3.
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Line Number	Continuous Current Rating Amps (1)	Withstand Currents	
		Short-Time Withstand (Symmetrical) kA (2)	Peak Withstand kA (3)
1	600	25	65
2	1200	38	99
3	1600	44	114
4	2000	44	114
5	2000	63	164
6	3000	63	164
7	3000	75	195
8	4000	75	195

NOTES:
(1) The ratio of the peak withstand current to short-time (symmetrical) withstand current is 2.6.
(2) Rated duration of the short-time (symmetrical) withstand current is 3 seconds with allowable I^2t variations given in IEEE C37.34.
(3) Rated duration of the peak withstand current test is 167 milliseconds.
(4) Peak withstand current (kA) $\cong$ 1.625 times the rms asymmetrical momentary current (kA). Switches previously rated at 40, 61, 70, 100, and 120 kA rms asymmetrical momentary are closely equivalent to the above peak withstand current ratings and do not require retesting.

5.7.3.1 Vertical Break Switch (Construction Classification A): "One in which the travel of the blade is in a plane perpendicular to the plane of the mounting base. The blade in the closed position is parallel to the mounting base." The hinge end includes two insulators, one of which is caused to rotate by the operating mechanism and thereby open and close the blade. See Figure 5-25.

Figure 5.-25: Vertically Mounted Vertical-Break Switch. Courtesy of Tuley & Associates, Inc.

5.7.3.2 Double Break Switch (Construction Classification B): "One that opens a conductor of a circuit at two points." The center insulator stack rotates to accomplish the opening and closing operation. See Figure 5-23.

5.7.3.3 Tilting-Insulator Switch (Construction Classifications C & F): "One in which the opening and closing travel of the blade is accomplished by a tilting movement of one or more of the insulators supporting the conducting parts of the switch." This type of switch is seldom used today. However, this switch is still in service on many existing installations. It is included here since it will be necessary to modify or replace such switches on occasion. See Figure 5-26.
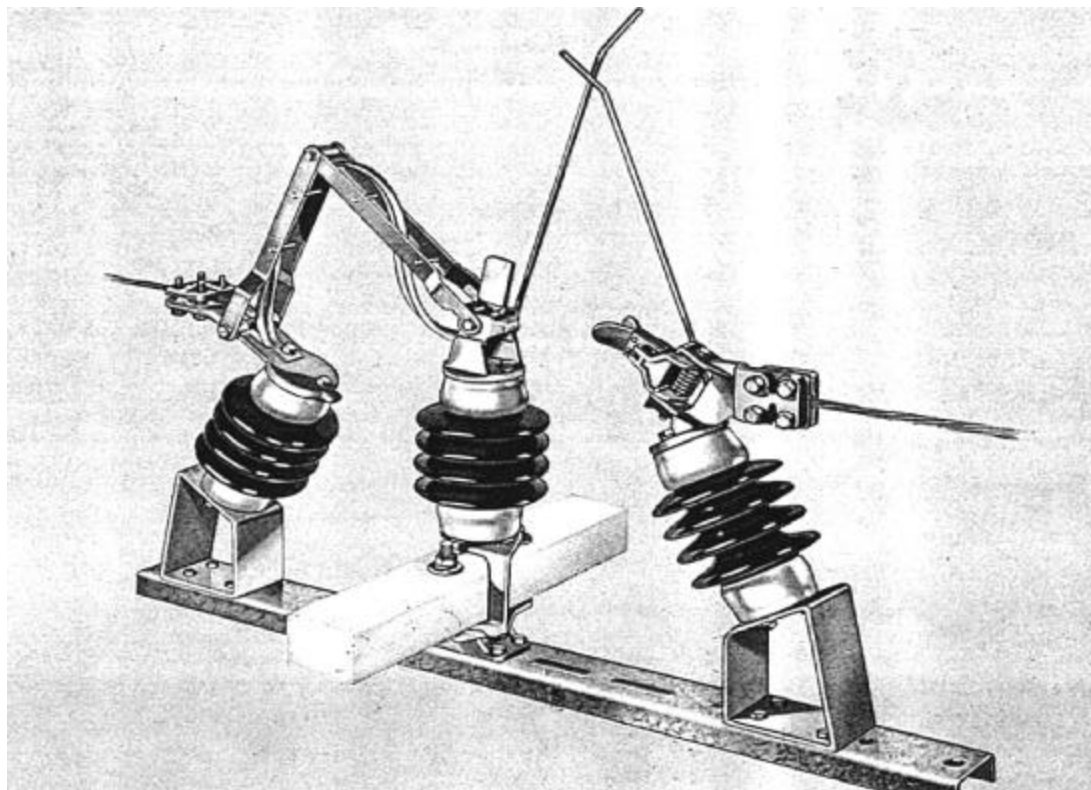
Figure 5-26: Tilting Insulator Switch. Courtesy of Kearney.

5.7.3.4 Side-Break Switch (Construction Classification D): "One in which the travel of the blade is in a plane parallel to the base of the switch." The hinge-end insulator rotates to accomplish the opening and closing operation. See Figure 5-27.

5.7.3.5 Center-Break Switch (Construction Classification E): One in which travel of the blade is in a plane parallel to the base of the switch and that opens in the center at only one point. Both insulators rotate to accomplish the opening and closing operation. See Figure 5-28.

5.7.3.6 Grounding Switch (Construction Classification G): As noted in Section 5.7.2.2, "a mechanical switching device by means of which a circuit or piece of apparatus may be electrically connected to ground." The pictorial representation in Table 5-39 shows a type where an insulated blade, connected to a bus or a piece of equipment, is made to contact ground. Some types use a normally grounded blade, which is made to contact the bus or equipment to be grounded. See Figure 5-22.
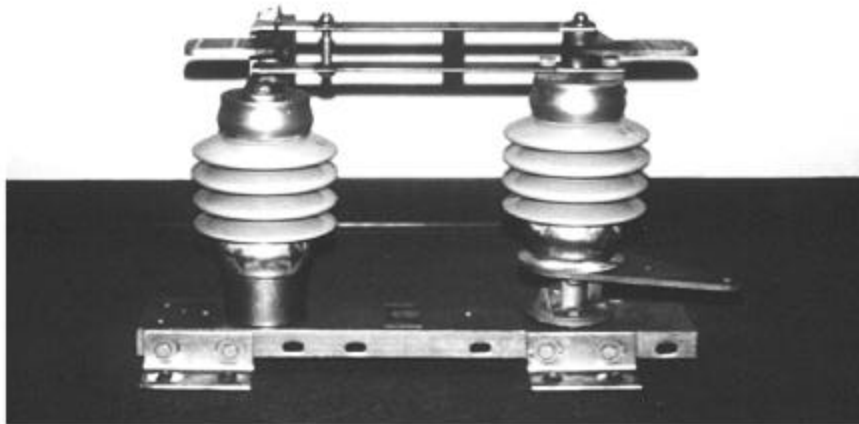
Figure 5-27: Single Side-Break Switch. Courtesy of Southern States, Inc.
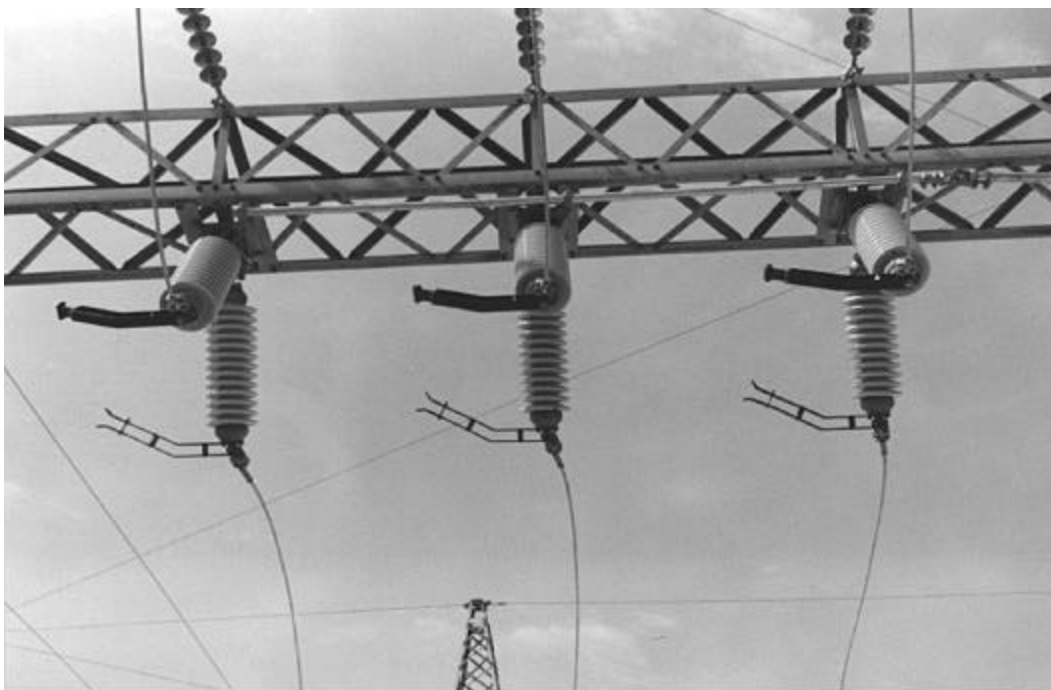
Figure 5-28: Underhung Center-Break V-Switch. Courtesy of Tuley & Associates, Inc.

5.7.3.7 Hook Stick Switch (Construction Classification H): One that is opened manually by means of a switch stick. Both insulators remain stationary when the blade, hinged at one end, is unlatched and opened or closed by the switch stick. These are single-pole (single-phase) switches. See Figure 5-29.

5.7.3.8 Vertical Reach Switch (Construction Classification J): "One in which the stationary contact is supported by a structure separate from the hinge mounting base. The blade in the closed position is perpendicular to the hinge mounting base." See Figure 5-30.
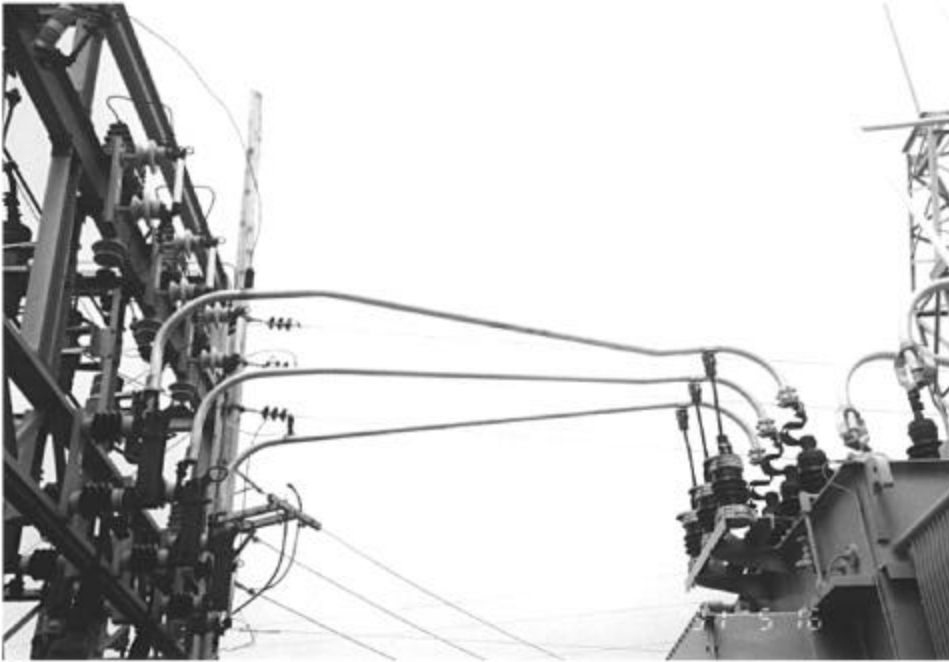
Figure 5-29: Hook Stick Switches on Structure at Termination of Bus from Transformer
(Coffeyville, Kansas)

Figure 5-30: Vertical Reach Switch. Courtesy of Southern States, Inc.

5.7.4 <u>Usual Service Conditions</u>

The ratings of all high-voltage air switches covered by the standards are based on the following.

5.7.4.1 Temperature: Ambient temperature of cooling air over the switch is within the range of -30°C to +40°C for non-enclosed indoor or outdoor switches. Ambient temperature of cooling air over the switch does not exceed 55°C for enclosed indoor or outdoor switches. Maximum ambient temperature outside the enclosure does not exceed 40°C.

5.7.4.2 Altitude: Altitude does not exceed 1000 meters (3300 feet). Correction factors should be applied above 1000 meters as shown in Table 5-41.

Table 5-41: Altitude Correction Factors for High-Voltage Air Switches. Ref. ANSI/IEEE Std. C37.30–1992, Table 1. Copyright © 1992. IEEE. All rights reserved.

Altitude		Altitude Correction Factor To Be Applied to:	
		Rated Withstand Voltage	Current Rating*
Feet	Meters	Col.1	Col. 2
3300	1000	1.00	1.00
4000	1200	0.98	0.995
5000	1500	0.95	0.99
6000	1800	0.92	0.985
7000	2100	0.89	0.98
8000	2400	0.86	0.97
9000	2700	0.83	0.965
10000	3000	0.80	0.96
12000	3600	0.75	0.95
14000	4200	0.70	0.935
16000	4800	0.65	0.925
18000	5400	0.61	0.91
20000	6000	0.56	0.90

NOTE 1: This table is being reviewed. Check later revisions of standard for values.
* For maximum ambient of 40°C for non-enclosed switches and 40°C outside the enclosure for enclosed switches.

5.7.5 <u>Ratings</u>

5.7.5.1 General: The various ratings covered by the ANSI Standards for the several types of air break switches are indicated by an "X" in Table 5-42. All these ratings are defined in ANSI/IEEE Std. C37.100. However, the main rating definitions applicable to "disconnecting switches" will be repeated here for convenience since this is the most common air switch used in substations. For the most part, the ratings repeated here also apply to the other switch types.

Table 5-42: Switch Ratings and Required Tests. Ref. IEEE C37.30-1997, Table 1.

Switch Rating	Disconnecting Switch	Interrupter Switch	Fault-Initiating Switch	Grounding Switch
	Column 1	Column 2	Column 3	Column 4
Rated power frequency	X	X	X	X
Rated maximum voltage	X	X	X	X
Rated continuous current	X	X	—	—
Rated dielectric withstand voltages	X	X	X	X
Rated lightning-impulse withstand (BIL)	X	X	X	X
Rated switching-impulse withstand (for rated maximum voltage of 362 kV and above)	X	X	X	X
Rated power frequency dry withstand	X	X	X	X
Rated power frequency wet withstand (outdoor)	X	X	X	X
Rated dew power frequency withstand (indoor)	X	X	X	X
Rated peak-withstand current	X	X	O	X
Rated short-time (symmetrical) withstand current	X	X	O	X
Rated short-time (symmetrical) withstand current duration	X	X	O	X
Rated mechanical operations	X	X	—	X
Rated mechanical terminal load	X	X	X	X
Rated ice-break ability – manual (outdoor)	X	X	X	X
Rated ice-break ability – power: single attempt opening and closing (outdoor)	X	X	X	X
Rated ice-break ability – power: single attempt opening, multiple attempt closing (outdoor)	X	X	—	X
Rated load-making current	O	X	—	X
Rated fault-making current		—	X	O
Rated switching parameters [a]				
Rated capacitance-switching overvoltage ratio[a]	—	X[b]	—	—
Rated minimum differential-capacitance voltage[a]	—		—	—
Rated maximum differential-capacitance voltage[a]	—	X[b]	—	—
Rated load-interrupting current and expected switching endurance[a]	—	O[c]	—	—
Rated unload transformer interrupting current and expected switching endurance[a]	—	O[c]	—	—
Rated single-capacitance interrupting current and expected switching endurance[a]	—	O[c]	—	—
Rated parallel-connected capacitance-switching current and expected switching endurance[a]	—	O[c]	—	—

NOTES: "X" indicates required rating; "O" indicates optional rating; "—" indicates not applicable.

     [a] Relates to interrupter switches and will be superseded by IEEE PC37.39 when it is completed and approved.

     [b] Required if the interrupter switch has capacitance-switching ratings.

     [c] At least one current-interrupting rating is required for interrupter switches.

5.7.5.2 Disconnecting Switch Ratings

5.7.5.2.1 Rated Voltage: Rated voltage "is the highest nominal system voltage on which it is intended to be applied."

5.7.5.2.2 Rated Maximum Voltage: Rated maximum voltage "is the highest rms voltage at which the device is designed to operate."

5.7.5.2.3 Rated Continuous Current: Rated continuous current "is the maximum direct current, or rms current, in amperes at rated frequency which it will carry continuously without exceeding the limit of observable temperature rise."

NOTE: Allowable continuous current at a "specific ambient temperature is the maximum direct or alternating current in amperes, rms at rated frequency which it will carry without exceeding the allowable temperature for any of its parts as listed in Column 1" of Table 5-43.

The allowable continuous current may be determined using Equation 5-5:

Equation 5-5

$$I_A = I_R \left(\frac{\theta_{max} - \theta_A}{\theta_r} \right)^{\frac{1}{2}}$$

Where:
  θ_A = Ambient temperature (°C)
  I_A = Allowable continuous current at θ_A
  I_R = Rated continuous current
  θ_{max} = Allowable temperature of switch part from Table 5-43
  θ_r = Limit of observable temperature rise (°C) at rated current of switch part from Table 5-43

The values of θ_r in Table 5-43 have been selected (when the switch is tested in accordance with Section 6 of IEEE Std. C37.34) to maintain a loadability of 1.22 at 25°C (77°F) where:

> Loadability of a non-enclosed air switch is the ratio of allowable continuous current at 25°C (77°F) ambient temperature to rated current. The loadability of an enclosed air switch is the ratio of allowable continuous current at 40°C (104°F) inside ambient temperature to rated current.

Users in colder climates and those with maximum load currents, known to occur during ambients lower than 40°C (104°F), should carefully consider the possible cost benefits from taking advantage of allowable continuous currents when selecting the continuous current rating of any air break switch. In such applications, a lower continuous current rating may be sufficient, compared to a rating based strictly on the maximum direct, or rms alternating current, of the circuit in question.

Table 5-43: Temperature Limitations for Air Switches. IEEE Std. C37.30–1997, Table 2.

	Allowable Max Temperature, θ_{max} (°C)	Nonenclosed Indoor and Outdoor Switches		Enclosed Indoor and Outdoor Switches	
		Limit of Observable Temperature Rise and Rated Current (θ_r) (°C) (see Note 1)	Switch Part Class Designation	Limit of Observable Temperature Rise at Rated Current, θ_r (°C)	Switch Part Class Designation
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
(1) Contacts in air (see Note 2)					
(a) Copper or copper alloy	75	33	BO2	20	QO$_3$3
(b) Copper or copper alloy to silver or silver alloy, or equivalent	90	43	DO4	33	RO4
(c) Silver, silver alloy, or equivalent	105	53	FO6	43	TO6
(d) Other (see Note 3)	—	—	—	—	—
(2) Conducting mechanical joints					
(a) Copper or aluminum	90	43	DO4	33	RO4
(b) Silver, silver alloy, or equivalent	105	67	FO6	57	TO6
(c) Other (see Note 3)	—	—	—	—	—
(3) Switch terminals with bolted connections	90	43	DO4	33	RO4
(4) Welded or brazed joints or equivalent	105	53	FO6	43	TO6
(5) Other current-carrying parts					
(a) Copper or copper alloy castings	105	53	FO6	43	TO6
(b) Hard drawn copper parts (see Note 4)	80	37	CO3	25	PO$_2$2
(c) Heat treated aluminum alloy parts	105	53	FO6	43	TO6
(d) Woven wire flexible connectors	75	33	BO2	20	QO$_3$3
(e) Other materials (see Note 3)	—	—	—	—	—
(6) Insulator caps and pins and bushing caps	110	57	GO7	47	UO7
(7) Current-carrying parts in contact with insulation materials					
(a) Insulation Class 90 °C	90	43	CO3	33	PO$_2$2
(b) Insulation Class 105 °C	105	53	EO5	43	SO5
(c) Insulation Class 130 °C	130	70	HO8	60	VO8
(d) Insulation Class 155 °C	155	87	IO9	77	WO9
(e) Insulation Class 180 °C	180	103	JO10	93	XO10
(f) Insulation Class 220 °C	220	130	KO11	120	YO11
(g) Oil (see Note 5)	90	43	DO4	33	RO4
(h) SF$_6$	350	307	—	297	—
(8) Nonenergizable parts subjected to contact by personnel					
(a) Handled by operator (see Note 6)	50	10	—	10	—
(b) Accessible to operator (see Note 6)	70	30	—	30	—
(c) Not accessible to operator (see Note 7)	—	—	—	—	—
(9) Entire switch in accordance with IEEE C37.30-1992					
(a) Outdoor	70	30	AO1	—	—
(b) Indoor	85	—	—	30	NO1

NOTES to Table 2:
(1) The limit of observable temperature rise listed in this column is suitable for use in rating switches for application in enclosures of IEEE C37.20.2–1993 and IEEE C37.20.3-1987, if the corresponding allowable maximum temperature listed in column 1 is not exceeded when in the enclosure. These temperature rises are chosen to give a loadability of 1.22 at 23°C.
(2) Contacts as used here include: (a) stationary and moving contacts that engage and disengage, and (b) contacts that have relative movement but remain engaged.
(3) Other materials may become available for contacts, conducting mechanical joints, and other current-carrying parts that have a different allowable maximum temperature, θ_{max}. Their limit of observable temperature rise at rated continuous current, θ_r, shall be related to their θ_{max} in accordance with 5.4.
(4) If annealing will not impair switch operation or reduce ability to meet any of the ratings, 105°C may be used for θ_{max} and the corresponding increase in θ_r as determined in 5.4.
(5) The top oil (upper layer) temperature shall not exceed 80°C total. The 90°C value refers to the hottest-spot temperature of parts where they contact the oil.
(6) It is assumed that any parts handled by or accessible to an operator will be in ambient air not to exceed 40°C.
(7) The maximum temperature of any nonenergizable part not accessible to the operator shall not exceed a temperature that will necessitate maintenance or replacement of parts during the life of the switch.

5.7.5.2.4 Rated Short-Time Current (Momentary and Three Second)

5.7.5.2.4.1 Rated momentary current "is the rms total current which the switch shall be required to carry for at least one cycle. The current shall be the rms value, including the direct-current component, during the maximum cycle as determined from the envelope of the current wave, and the test period shall be at least ten cycles."

5.7.5.2.4.2 Rated three-second current is the rms total current, including any direct current component, that the switch shall be required to carry for three seconds.

5.7.5.2.5 Rated Withstand Voltage: Rated withstand voltage "shall be the voltage which the device has to withstand without flashover or other electric failure when voltage is applied under specified conditions." The standard low-frequency wet and dry and 1.2 x 50 microsecond impulse withstand voltages are listed in ANSI Std. C37.32.

5.7.5.2.6 Preferred Ratings: The preferred ratings of voltage, continuous current, short-time current ratings, dielectric withstand voltages, and radio influence test voltages of various constructions of outdoor air switches (at 60 Hz) shall be in accordance with Tables 5-38, 5-39, and 5-40.

5.7.6 **Other Requirements**

5.7.6.1 Insulators: Insulators used need to have sufficient strength to withstand the magnetic forces produced by the rated momentary current ratings specified in Table 5-40.

An approximation of the electromagnetic force exerted between two current-carrying conductors is given by Equation 5-6 (from ANSI Std. C37.32):

Equation 5-6

$$F = M\left(\frac{5.4 \times I^2}{S \times 10^7}\right)$$

Where:

F = Pounds per foot of conductor
M = Multiplying factor (determined from Table 5-44)
I = Short-circuit maximum peak current in amperes in accordance with Table 5-44
S = Spacing between centerlines of conductors in inches

The force calculated from the above operation will, in most cases, be conservative, tending to compensate for the neglect of resonant forces. It should, therefore, be reasonably accurate for the majority of practical situations.

Table 5-44: Multiplying Factor (M) for Calculation of Electromagnetic Forces.
Ref. ANSI Std. C37.32–1996, Annex A.3.2.
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Circuit	Amperes (I) Expressed as	Multiplying Factor (M)
dc	maximum peak	1.0
ac, 3-phase	maximum peak	0.866
ac, 3-phase	rms asymmetrical	$(0.866 \times 1.63^2) = 2.3$
ac, 3-phase	rms symmetrical	$(0.866 \times 2.82^2) = 6.9$
1 phase of 3-phase or 1-phase	maximum peak	1.0
1 phase of 3-phase or 1-phase	rms asymmetrical	$(1.63^2) = 2.66$
1 phase of 3-phase or 1-phase	rms symmetrical	$(2.82^2) = 8.0$

5.7.6.2 Terminal Loadings: Terminal pad loadings should be in accordance with Table 5-45.

The arrangement of bolt hole centerlines in terminal pads should be in accordance with Figure 5-31. Holes should accommodate bolts ½ inch (12.7 mm) in diameter.

1. Two or more interleaved 4-hole pad configurations can be used as shown in Figure 5-31(b) (of ANSI Std. C37.32-1996).

2. All dimensions are in inches and millimeters.

Table 5-45: Terminal Loadings for High-Voltage Switches. Ref. ANSI Std. C37.32-1996, Table 2.
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Line Number	Maximum voltage kV	Current rating amps	F_1 and F_2		F_3		F_4	
			lbs	(N)	lbs	(N)	lbs	(N)
	(1)	(2)	(3)		(4)		(5)	
1	4.8–72.5	200-1200	90	(400)	30	(130)	30	(130)
2		>2000	90	(400)	30	(130)	30	(130)
3	121–169	600–1600	120	(530)	40	(180)	110	(490)
4		>2000	120	(530)	40	(180)	250	(1110)
5	242–362	1200–1600	180	(800)	60	(270)	375	(1670)
6		>2000	230	(1020)	75	(330)	685	(3040)
7	$\geq$500	All	450	(2000)	150	(670)	750	(3330)

NOTES:
[1] Terminal pad loading F_1, F_2, F_3, and F_4 incorporate considerations for typical weights of connected bus conductors having ice and wind loads, expansion loads, and limited moment forces. It is recommended that the manufacturer be consulted on forces that exceed those given in the table. These higher forces may be due to long bus spans rigidly connected to switches, extra high short circuit current forces, bus spans other than aluminum tube conductors, and other forces not considered.

[2] These loadings were derived for the mechanical operations requirement of IEEE C37.34, Clause 11 and do not necessarily represent the mechanical loading limit on terminals. Consult the manufacturer when actual valves are needed.

[3] At 242 kV and above, F_4 forces may be reduced by 40% for switches with hinged or pivoting-type terminal pads.

1 MIN
(25.4)

5/8 (15.9)
1-3/4 (44.4)
5/8 (15.9)

(a)

3 MIN
(76.2)

5/8 (15.9)   1-3/4 (44.4)   5/8 (15.9)

3 MIN (76.2)

(b)

5 MIN
(127.0)

5/8 (15.9) MIN

1-3/4 (44.4)

3 MIN (76.2)

5/8 (15.9) MIN

5/8 (15.9) MIN   1-3/4 (44.4)   1-3/4 (44.4)   5/8 (15.9) MIN

(c)
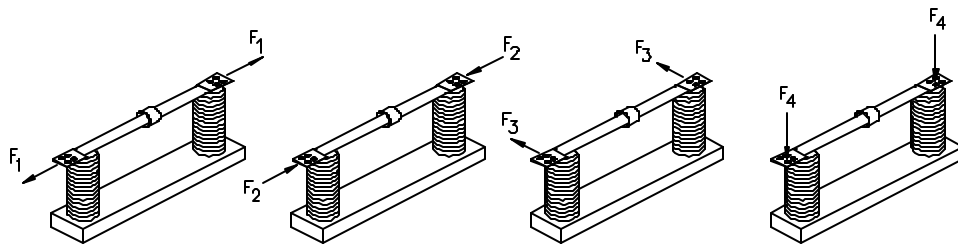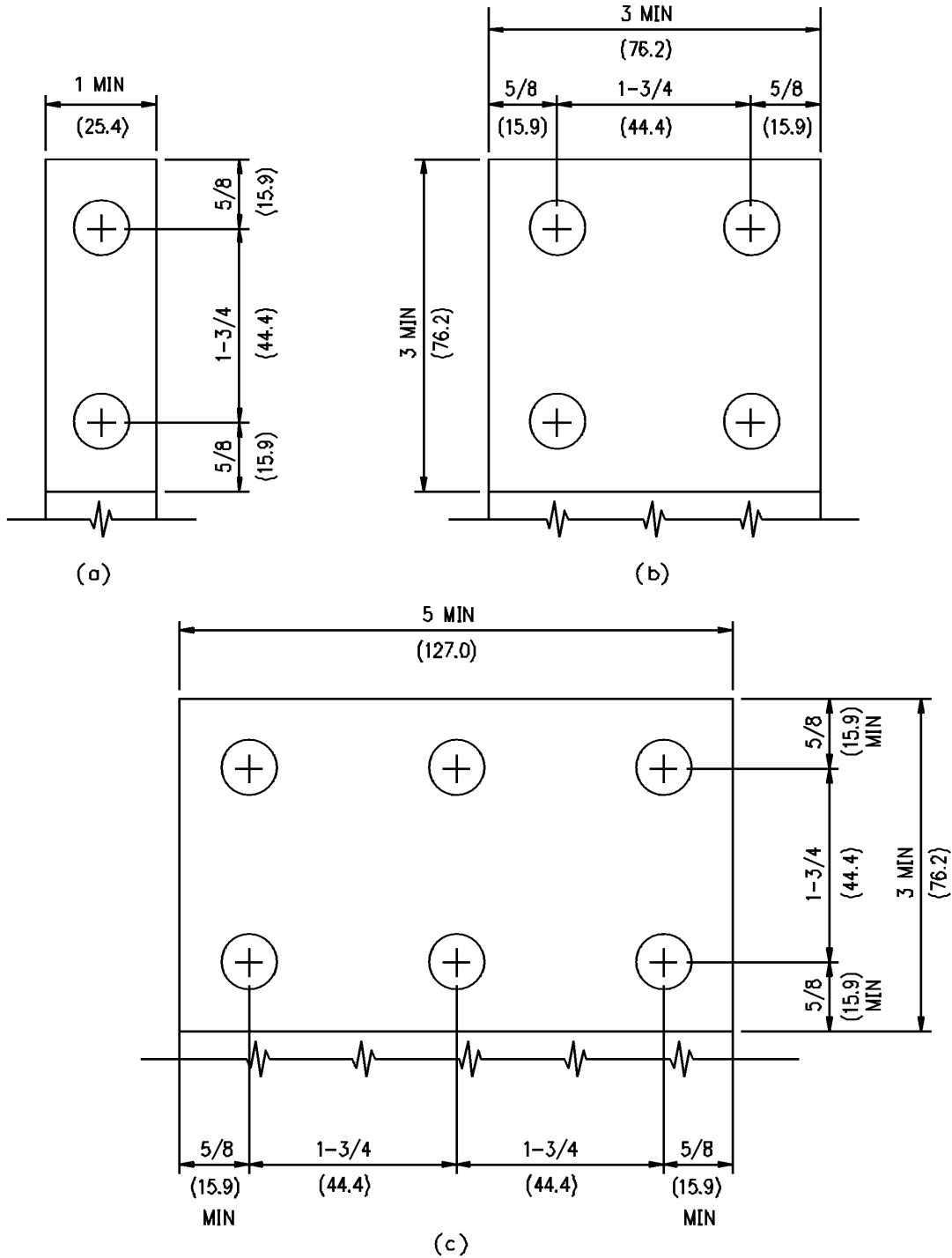
1. TWO OR MORE INTERLEAVED 4-HOLE PAD CONFIGURATIONS CAN BE USED AS SHOWN IN FIGURE 1(b).
2. ALL DIMENSIONS ARE IN INCHES AND MILLIMETERS.

Figure 5-31: Arrangement of Bolt Hole Centerlines in Terminal Pads. Ref. ANSI Std. C37.32-1996,
Figure 1. Reproduced with permission of the National Electrical Manufacturers Association.

5.7.6.3 Outdoor Air Switch Break Length: The length of break of outdoor air switches, when in the full open position, shall be such that the open gap or gaps will withstand a test voltage that is 10 percent in excess of the low-frequency impulse and dry withstand test voltages given in Table 5-38.

5.7.6.4 Break Distances and Spacing: The minimum metal-to-metal single-pole break distances and the single-pole centerline-to-centerline spacing of insulator columns needs to be as specified in Table 5-46 (see page 317 of this bulletin).

5.7.6.5 Base Mounting Holes: Base mounting holes for outdoor air switches shall be as specified in Table 5-47.

Table 5-47: Station-Class Outdoor Air Switches Preferred Mounting Hole Spacing
for 600-, 1200-, and 1600-Ampere Switches. Ref. ANSI Std. C37.32-1996, Table 7.
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Line No.	Rated Max. Voltage kV rms	Hook stick				Single side break				Vertical break			
		A In. (mm)		B In. (mm)		A In. (mm)		B Inches (mm)		A In. (mm)		B In. (mm)	
	(1)	(2)		(3)		(4)		(5)		(6)		(7)	
1	8.25	18	(457)	2 or 7	(50.8 or 178)	24	(610)	3 or 7	(76.2 or 178)	36	(914)	3 or 7	(76.2 or 178)
2	15.5	21	(533)	2 or 7		24	(610)	3 or 7		36	(914)	3 or 7	
3	25.8	24	(610)	2 or 7		27	(686)	3 or 7		39	(991)	3 or 7	
4	38.0	30	(762)	2 or 7		33	(838)	3 or 8-1/4	(76.2 or 210)	48	(1220)	3 or 8-1/4	(76.2 or 210)
5	48.3	39	(991)	3 or 8-1/4	(76.2 or 210)	39	(991)	3 or 8-1/4		54	(1370)	3 or 8-1/4	
6	72.5	51	(1290)	3 or 8-1/4		51	(1290)	3 or 8-1/4		69	(1750)	3 or 8-1/4	
7	121	66	(1680)	3 or 8-1/4		72	(1830)	8-1/4	(210)	87	(2210)	8-1/4	(210)
8	145	78	(1980)	3 or 8-1/4		84	(2130)	8-1/4		99	(2510)	8-1/4	
9	169	90	(2290)	8-1/4	(210)	96	(2440)	8-1/4		111	(2820)	8-1/4	

NOTES:
[1] "A" is the dimension along the length of the base and "B" is the dimension along the width of the base in inches.
[2] Dimensions for switches above 169 kV have not yet been established.
[3] Millimeter values approximate 25.4 mm per inch.

5.7.6.6 Phase Spacing: Phase spacing (pole spacing), centerline-to-centerline, for outdoor air switches needs to be as specified in Table 5-48.

Table 5-46: Station-Class Outdoor Air Switch—Pole Unit Dimensions. Ref. ANSI Std. C37.32-1996, Table 6.
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Line Nos.	Rated Maximum Voltage kV rms	Rated Lightning Impulse Withstand Voltage kV Peak	Length of Break Minimum Metal-to-Metal[1] Single Break Distance Inches (mm)		Double Break Distance Inches (mm)		Insulator Centerline-to-Centerline Phase Spacing Inches Minimum[1] (mm) Single Break Insulator Strength Standard		High		Double Break Insulator Strength Standard		High	
	(1)	(2)	(3)		(4)		(5)		(6)		(7)		(8)	
1	8.3	95	7	(178)	--		12	(305)	15	(381)	--		--	
2	15.5	110	10	(254)	--		15	(381)	18	(457)	--		--	
3	25.8	150	12	(305)	--		18	(457)	21	(533)	--		--	
4	38.0	200	18	(457)	12	(305)	24	(610)	27	(686)	18	(457)	21	(533)
5	48.3	250	22	(559)	15	(381)	30	(762)	33	(838)	23	(585)	24	(610)
6	72.5	250	22	(559)	15	(381)	30	(762)	33	(838)	23	(585)	24	(616)
7	72.5	350	32	(813)	22	(559)	42	(1067)	45	(1140)	30	(762)	34	(864)
8	121	350	32	(813)	22	(559)	42	(1067)	45	(1140)	30	(762)	34	(864)
9	121	450	See Note 2		See Note 2		51	(1295)	54	(1370)	35	(889)	—	
10	121	550	50	(1270)	32	(813)	60	(1520)	—		42	(1067)	—	
11	145	350	32	(813)	22	(559)	42	(1067)	45	(1140)	30	(762)	34	(864)
12	145	450	See Note 2		See Note 2		51	(1295)	54	(1370)	35	(889)	—	
13	145	550	50	(1270)	32	(813)	60	(1520)	—		42	(1067)	—	
14	145	650	60	(1520)	38	(965)	72	(1830)	—		48	(1220)	—	
15	169	450	See Note 2		See Note 2		51	(1295)	54	(1370)	35	(889)	—	
16	169	550	50	(1270)	32	(813)	60	(1520)	—		42	(1067)	—	
17	169	650	60	(1520)	38	(965)	72	(1830)	—		48	(1220)	—	
18	169	750	68	(1730)	44	(1120)	84	(2130)	—		54	(1370)	—	
19	242	550	50	(1270)	32	(813)	60	(1520)	—		42	(1067)	—	
20	242	650	60	(1520)	38	(965)	72	(1830)	—		48	(1220)	—	
21	242	750	68	(1730)	44	(1120)	84	(2130)	—		54	(1370)	—	
22	242	900	84	(2130)	50	(1270)	96	(2440)	—		68	(1730)	—	
23	242	1050	104	(2640)	57	(1450)	116	(2950)	—		75	(1900)	—	
24	362	1050	104	(2640)	57	(1450)	116	(2950)	—		75	(1900)	—	
25	362	1300	120	(3050)	66	(1680)	132	(3350)	—		84	(2130)	—	
26	550	1550	See Note 2		—		See Note 2		—		—		—	
27	550	1800	See Note 2		—		See Note 2		—		—		—	
28	800	2050	—		—		—		—		—		—	

NOTES:

1. The design of some switches may be such that the minimum metal-to-metal distance and the centerline-to-centerline spacing conflict. Where this occurs, the minimum metal-to-metal distance should be used. Minimum metal-to-metal distances may be modified provided proof of performance is substantiated by dielectric tests.

2. Values have not yet been established.

Table 5-48: Phase Spacing and Ground Clearance for Station-Class Outdoor Air Switches and Bus Supports. Ref. ANSI Std. C37.32–1996, Table 5. Reproduced with permission of the National Electrical Manufacturers Association.

Line No.	Rated Max. Voltage	Rated Lightning Withstand Voltage[1]	Min. Metal-to-Metal Distance Disconnecting Switches, Bus Supports, and Rigid Conductors[2]		Ground Clearance[3]				Centerline-to-Centerline Phase Spacing[4]					
					Recommended		Minimum		Vertical Break Disconnecting Switches and Bus Supports		Side Break (Horizontal Break) Disconnecting Switches		All Horn Gap Switches (Vertical and Side Break)	
	kV rms	kV Peak	inches	mm	inches	mm	inches	mm	inches	mm	inches	mm	inches	mm
	(1)	(2)	(3)		(4)		(5)		(6)		(7)		(8)	
1	8.25	95	7	178	7.5	191	6	152	18	457	30	762	36	914
2	15.5	110	12	305	10	254	7	178	24	610	30	762	36	914
3	25.8	150	15	381	12	305	10	254	30	762	36	914	48	1220
4	38.0	200	18	457	15	381	13	330	36	914	48	1220	60	1520
5	48.3	250	21	533	18	457	17	432	48	1220	60	1520	72	1830
6	72.5	250	21	533	18	457	17	432	48	1220	60	1520	72	1830
7	72.5	**350**	31	787	29	737	25	635	60	1520	72	1830	84	2130
8	121	350	31	787	29	737	25	635	60	1520	72	1830	84	2130
9	121	450	44	1118	39	991	34	846	72	1830	91	2310	103	2620
10	121	**550**	53	1350	47	1193	42	1067	84	2130	108	2740	120	3050
11	145	350	31	787	29	737	25	635	60	1520	72	1830	84	2130
12	145	450	44	1118	39	991	34	846	72	1830	91	2310	103	2620
13	145	550	53	1350	47	1193	42	1067	84	2130	108	2740	120	3050
14	145	**650**	63	1600	52.5	1333	50	1270	96	2440	132	3350	144	3660
15	169	450	44	1118	39	991	34	846	72	1830	91	2310	103	2620
16	169	550	53	1350	47	1193	42	1067	84	2130	108	2740	120	3050
17	169	650	63	1600	52.5	1333	50	1270	96	2440	132	3350	144	3660
18	169	**750**	72	1830	61.5	1562	58	1473	108	2740	156	3960	168	4270
19	242	550	53	1350	47	1193	42	1067	84	2130	108	2740	120	3050
20	242	650	63	1600	52.5	1333	50	1270	96	2440	132	3350	144	3660
21	242	750	72	1830	61.5	1562	58	1473	108	2740	156	3960	168	4270
22	242	**900**	89	2260	76	1930	71	1803	132	3350	192	4870	192	4870
23	242	1050	105	2670	90.5	2299	83	2108	156	3960	216	5500	216	5500
24	362	1050	105	2670	90.5	2299	84	2134	156	3960	216	5500	216	5500
25	362	**1300**	119	3020	106	2692	104	2642	174	4430	See Note 5		240	6100
26	550	1550	See Note 5		See Note 5		124	3150	See Note 5		See Note 5		300	7620
27	550	**1800**	See Note 5		See Note 5		144	3658	See Note 5		See Note 5		324	8230
28	800	2050	See Note 5		See Note 5		166	4216	See Note 5		See Note 5		600	15240

[1] Close lightning arrester coordination may allow lower lightning impulse values. Traditional values shown in bold font.

[2] Minimum metal-to-metal distance may be modified providing proof of performance is substantiated by dielectric test.

[3] Ground clearances for switches with voltages 362 kV and above are based on switching surge voltage levels. Refer to bibliography, Annex C [of ANSI Std. C37.32-1996].

[4] The phase spacings in columns 6, 7, and 8 are recommended values. Overall width of switch and bus support energized parts, angle of opening of side-break switches, etc., may allow a reduction in phase spacing dependent upon voltage concentration on sharp projections. Resultant metal-to-metal distances between phase energized parts should not be less than that shown in Column 3.

[5] Values not yet established.

5.7.6.7 Ratings and Requirements for Switches: Preferred ratings and other requirements for indoor air switches, grounding switches, fault initiating switches and load interrupter switches are listed in ANSI Std. C37.32, Sections 5 through 8, respectively. Tables 5-49 through 5-51 list ratings and requirements applicable to indoor air switches and grounding switches.

Table 5-49: Preferred Ratings for Indoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 12.
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Line No.	Rated Max. Voltage kV rms	Rated Withstand Voltage			Continuous Current Rating (Amperes, rms)								
		Impulse Lightning kV Peak	Power Frequency kV rms		200	400	600	1200	2000	3000	4000	5000	6000
			Dew 10 Sec.	Dry 1 Min.	Short-time (symmetrical) current ratings, thousands of amperes rms [1]								
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	4.8	60	15	19	12.5	12.5	25	38	50	63	--	--	--
2	8.25	75	24	26	12.5	12.5	25	38	50	63	75	100	125
3	15.0	95	26	36	12.5	12.5	25	38	50	63	75	100	125
4	15.5	110	30	50	12.5	12.5	25	38	50	63	75	100	125
5	25.8	125	40	60	—	12.5	25	38	50	63	75	100	—
6	38.0	150	—	80	—	12.5	25	38	50	63	75	—	—

[1] Short-time current ratings include a momentary current rating and a 3-second current rating, based on the test conditions described in Section 5 of ANSI/ IEEE C37.34. Divide the momentary current rating by 1.6 to obtain the 3-second ratings.

NOTES:
[1] Withstand current ratings include a peak withstand current rating as well as a short-time (symmetrical) withstand current rating as shown.
[2] The ratio of the peak withstand current to short-time (symmetrical) withstand current is 2.6.
[3] Rated duration of the short-time (symmetrical) withstand current is three (3) seconds with allowable I^2t variations given in IEEE C37.34.
[4] Rated duration of the peak withstand current test is 167 milliseconds.

Table 5-50: Indoor Air Switches and Bus Supports—Phase Spacing and Length of Break.
Ref. ANSI Std. C37.32-1996, Table 13.
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Line No.	Rated Max. Voltage kV rms	Phase Spacing Minimum Metal-to-Metal Clearance Disconnecting Air Switches and Bus Supports Inches[1]		Length of Break Minimum Metal-to-Metal Single-Break Distances Inches [2]	
	(1)	(2)		(3)	
		Inches	(mm)	Inches	(mm)
1	4.8	4- 1/2	(114)	4-1/2	(114)
2	8.25	6	(152)	6	(152)
3	15.0	7-1/2	(190)	7-1/2	(190)
4	15.5	9	(229)	9	(229)
5	25.8	13	(330)	13	(330)
6	38.0	18	(457)	18	(457)

NOTE – Millimeter values approximate 25.4 mm per inch.

[1] Barriers may be used to provide additional safety during operation by preventing accidental contact with live parts. The provision of adequate insulating barriers may allow a modification of these clearances. These minimum clearances may be modified provided proof of performance is substantiated by dielectric test (with due consideration to the effects of electromagnetic forces) in accordance with the values shown in columns 2 and 4 of table 12. When indoor switches are mounted in equipment covered by other standards, minimum clearances may be modified by such standards.

[2] Minimum metal-to-metal distances may be modified from the values listed above provided proof of performance is substantiated by the dielectric test in accordance with Clause 4 of IEEE C37.34.

Table 5-51: Grounding Switch Electrical Clearance.
Ref. ANSI Std. C37.32-1996, Table 14.
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Line No.	Rated Maximum Voltage kV rms	Rated Lightning Impulse Withstand Voltage kV Peak	Minimum Gap – Ground Switches to Live Parts	
			inches	mm
	(1)	(2)	(3)	
INDOOR				
1	4.8	60	2.0	50.8
2	8.25	75	2.0	50.8
3	15.0	95	2.0	50.8
4	15.5	110	2.0	50.8
5	25.8	125	3.0	76.2
6	38.0	150	4.0	102
DISTRIBUTION CLASS OUTDOOR				
7	8.25	75	2.0	50.8
8	15.0	95	2.0	50.8
9	27.0	125	3.0	76.2
10	38.0	150	4.0	102
STATION CLASS OUTDOOR				
11	8.25	95	2.0	50.8
12	15.5	110	2.0	50.8
13	25.8	150	4.0	102
14	38.0	200	6.0	152
15	48.3	250	9.5	241
16	72.5	250	9.5	241
17	72.5	350	14	367
18	121	350	14	367
19	121	450	18	457
20	121	550	22	559
21	145	350	14	367
22	145	450	18	457
23	145	550	22	559
24	145	650	27	686
25	169	450	18	457
26	169	550	22	559
27	169	650	27	686
28	169	750	31	787
29	242	550	22	559
30	242	650	27	686
31	242	750	31	787
32	242	900	38	965
33	242	1050	44	1118
34	362	1050	47	1194
35	362	1300	50	1270
36	550	1550	75	1905
37	550	1800	85	2159
38	800	2050	112	2845

NOTE – These gap distances are not a requirement for grounding blades that operate in a plane perpendicular to the main switch base.

5.7.6.8 Outdoor Air Switch Hook Dimensions: Outdoor air switch hook dimensions shall be in accordance with Figure 5-32.
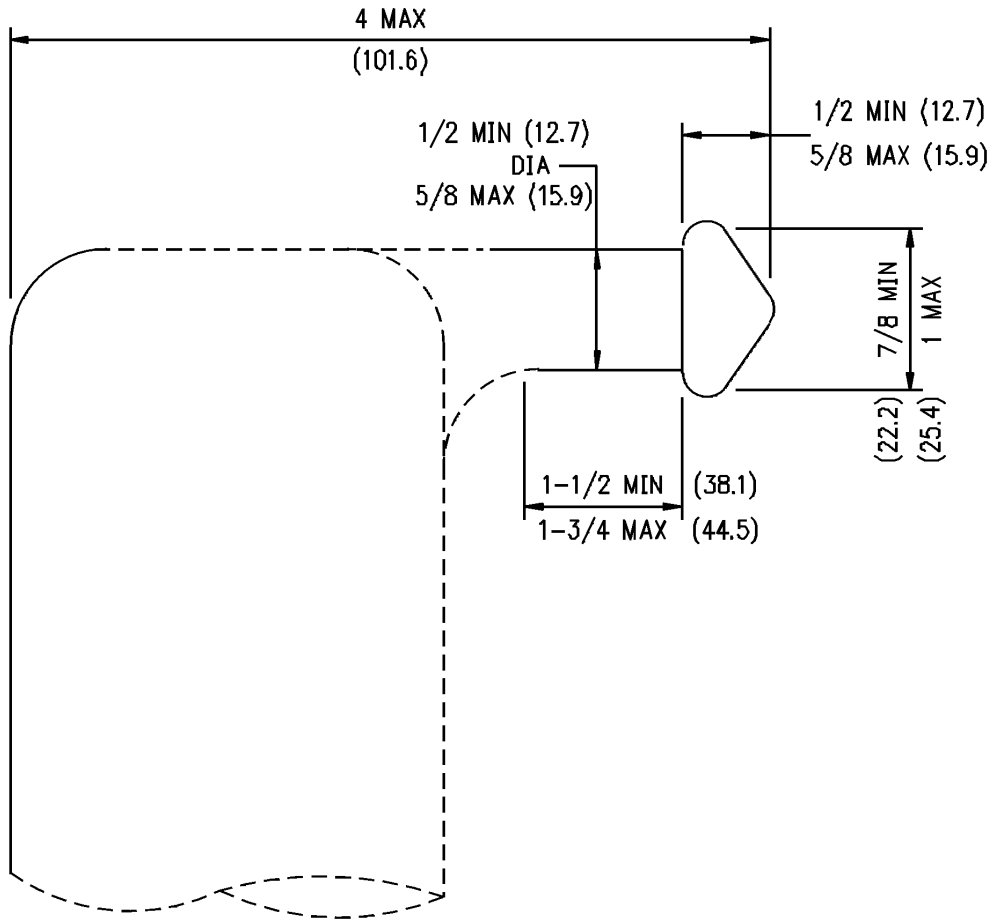
NOTES:
1. All dimensions are in inches (millimeter values are approximate).
2. Dimensions that are not shown are optional.

Figure 5-32: Outdoor Air Switch Hook Dimensions. Ref. ANSI Std. C37.32-1996, Figure 2. Reproduced with permission of the National Electrical Manufacturers Association.

5.7.7 <u>Mounting Considerations</u>

5.7.7.1 Supports: Air switches should be mounted on supports strong enough to ensure that current carrying contacts mate properly when opened and closed, since considerable reaction forces are exerted on the supports during operation.

5.7.7.2 Orientation: Whenever possible, air switches should be oriented so that the blade is dead when the switch is open.

5.7.7.3 Mounting Arrangement: The intended mounting arrangement of air break switches should be made known to the manufacturer so that the insulators will be properly assembled.

5.7.8 References

ANSI Std. C29.1, "Test Methods for Electrical Power Insulators."

ANSI Std. C29.8, "Wet-Process Porcelain Insulators (Apparatus, Cap and Pin Type)."

ANSI Std. C29.9, "Wet-Process Porcelain Insulators (Apparatus, Post Type)."

ANSI Std. 29.10, "Wet-Process Porcelain Insulators (Indoor Apparatus Type)."

ANSI Std. C37.32, "Standard for Switchgear—High-Voltage Air Switches, Bus Supports, and Switch Accessories-Schedules of Preferred Ratings, Manufacturing Specifications and Application Guide."

ANSI Std. C37.33, "High-Voltage Air Switches—Rated Control Voltages and Their Ranges."

ANSI/IEEE Std. C37.100, "Standard Definitions for Power Switchgear."

ANSI/IEEE Std. 142, "IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (IEEE Green Book)."

IEEE Std. C37.30, "Standard Requirements for High-Voltage Air Switches."

IEEE Std. C37.34, "Test Code for High-Voltage Air Switches."

IEEE Std. C37.35, "Guide for the Application, Installation, and Operation and Maintenance of High-Voltage Air Disconnecting and Load-Interrupter Switches."

NEMA Std. SG-6, "Power Switching Equipment."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

5.8 SURGE ARRESTERS

5.8.1 General

This section deals with the application of surge arresters for the protection of equipment in substations. While information is provided for silicon-carbide valve arresters, metal oxide arresters are preferred and recommended due to their improved protective characteristics. Although the surge arrester is an essential component in insulation coordination, a complete description of the total concept of insulation coordination is beyond the scope of this bulletin.

Surge arresters are the basic protective devices against system transient overvoltages that may cause flashovers and serious damage to equipment. They establish a baseline of transient overvoltage above which the arrester will operate to protect the equipment. When a transient overvoltage appears at an arrester location, the arrester conducts internally and discharges the surge energy to ground. Once the overvoltage is reduced sufficiently, the arrester seals off, or stops conducting, the flow of power follow current through itself and the circuit is returned to normal. As voltage-sensitive devices, arresters have to be carefully selected to correlate properly with the system operating voltages.

5.8.2 Classification of Arresters

Surge arresters are classified as station, intermediate, and distribution arresters. Classifications are determined by prescribed test requirements. Primary differences in the use of the classes involve the voltage levels the arresters will withstand and protect and the current levels the arresters will discharge. All three classes may be used in substation applications.

Test requirements for gapped silicon-carbide arresters are listed in IEEE Std. C62.1. Table 5-52 indicates the voltage ratings for surge arresters. Table 5-53 indicates the pressure-relief test currents for the station- and intermediate-class arresters. The application of gapped silicon-carbide surge arresters is described in ANSI Std. C62.2. The major protective characteristics of the gapped silicon-carbide arresters are summarized in Tables 5-54, 5-55, and 5-56.

Table 5-52: Arrester Voltage Ratings in Kilovolts.
Ref. IEEE C62.1-1989, Table 1. Copyright © 1989. IEEE.
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Secondary Arresters	Distribution Arresters	Intermediate Arresters	Station Arresters
0.175			
0.650			
	1		
	3	3	3
	9	9	9
	10		
	12	12	12
	15	15	15
	18		
	21	21	21
		24	24
	25		
	27		
	30	30	30
		36	36
		39	39
		48	48
		60	60
		72	72
		90	90
		96	96
		108	108
		120	120
			144
			168
			180
			192
			240
			258
			276
			294
			312
			372
			420
			444
			468
			492
			540
			576
			612
			648
			684

NOTE: Because of the more stringent requirements for the
protection of rotating machines, the use of arresters (all
classes) rated 4.5, 7.5, 16.5, 18, 19.5, 22.5, 24, 25.5, and 27
kV is recognized for this application.

Table 5-53: Pressure-Relief Test Currents for Station and
Intermediate Arresters. Ref. IEEE C62.1-1989, Table 5.
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	Symmetrical rms Amperes	
	High Current	Low Current
Station 3–15 kV ratings *	65000 or 25000	600±200
21–684 kV ratings **	40000 or 25000	600±200
Intermediate 3–120 kV ratings *	16100	600±200

* Test values for arresters with porcelain tops have not
been standardized.

** For applications requiring currents above 40 kA,
ratings of 45, 55, or 60 kA shall be used.

NOTE: It is permissible to determine the prospective
currents by making the bolted fault test with reduced
excitation on the generator (this reduces the duty on the
test equipment). The short-circuit currents and the
open-circuit voltage, E_R, with the reduced excitation shall
be measured. The prospective currents of the test
circuit are the measured short-circuit currents multiplied
by E_T/E_R.

Table 5-54: Protective Characteristics of Gapped Silicon-Carbide Station Arresters. Ref. ANSI/IEEE C62.2-1987, Table A1.
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Voltage Rating of Arrester (kV rms)	Impulse Sparkover Voltage		1.2/50-µs kV Crest (Range of Maxima)	Switching Surge Sparkover Voltage kV Crest (Range of Maxima)	Discharge Voltage for 8/20-µs Discharge Current Wave					
	Front-of-Wave				kV Crest for 1500A (Range of Maxima)	kV Crest for 3000A (Range of Maxima)	kV Crest for 5000A (Range of Maxima)	kV Crest for 10 000A (Range of Maxima)	kV Crest for 20 000A (Range of Maxima)	kV Crest for 40 000A (Range of Maxima)
	Rate of Rise Test Voltage (kV/µs)	kV Crest (Range of Maxima)								
3	25	10-18	10-14	-	4.7-6	5.3-6.5	6-7	6.7-7.5	7.7-8.3	-9.2
6	50	19-28	16-23	-	9.3-11	10-12	11.9-13	13.4-14.3	15.3-16.3	-18.5
9	75	28.5-38	24-32	-	13.9-17	16-18	17.8-19	20-21.5	22.9-24.3	-28
12	100	36-48	32-41	-	18.5-22	21.3-24	23.5-25.5	26.7-28.5	30.1-32.1	-37
15	125	45-57	40-51	-	23.1-27.5	26.6-30	29.5-32	33.4-36	38.2-40	-46
21	175	63-76	54-68	-	32.3-38.5	37.2-42	41-45	46.8-50	53.4-55.5	-65
24	200	71-86	62-77	-	36.9-44	42.5-48	47-51	53.4-57	61-63.5	-74
30	250	89-103	77-93	-	46.1-55	53.1-60	59-64	66.9-72	76.3-79	-92.5
36	300	107-118	92-108	-	55.3-66	63.7-72	70.5-76	80-85	91.5-94.5	-111
39	325	115-125	100-114	-	60-71.5	69-78	76.5-82.5	56.5-92	99.1-102	-120
48	400	143-148	122-132	-	73.8-88	84.9-96	94-102	106-114	122-126	-148
60	500	170-190	141-165	136-153	95-109	110-120	118-130	132-143	150-158	-185
72	600	204-226	169-190	163-178	114-131	130-144	141-155	159-170	180-189	-222
90	750	254-275	210-235	203-215	142-163	162-180	176-194	199-213	225-237	-277
96	800	270-295	218-245	218-225	151-174	173-192	188-218	212-227	240-253	-296
108	900	304-325	245-270	245-250	170-196	194-216	212-245	238-256	270-284	-333
120	1000	338-360	272-300	272-275	188-218	216-240	235-272	265-285	300-319	-370
144	1200	400-430	326-346	325-326	226-262	260-288	282-311	318-342	360-379	-444
168	1400	460-525	380-404	380-381	263-305	303-336	329-362	371-399	420-442	-517
180	1500	490-565	400-430	400-410	281-327	324-360	353-388	397-427	450-495	-554
192	1600	520-600	427-460	426-435	300-348	346-384	376-414	424-455	480-505	-591
240	2000	620-735	535-577	533-545	374-436	432-480	470-518	530-570	605-630	-739
258	2000	760-790	575-620	573-585	402-438	465-474	505-515	569-575	650-666	-795
276	2000	805-840	615-664	612-630	429-468	496-507	540-570	609-615	690-714	-850
294	2000	875-885	653-675	653-675	458-472	528-532	576-595	653-653	735-758	-906
312	2000	924-935	690-750	693-710	485-530	562-574	611-620	688-693	780-805	874-961
372	2000	1078-1100	870-890	790-830	562-610	655-680	726-738	809-826	932-955	1136-1145
396	2000	1140-1176	925-950	840-885	599-672	697-726	734-785	861-880	990-1015	1109-1226
420	2000	1200-1250	980-1005	890-940	634-713	739-770	819-830	913-930	1050-1070	1176-1294
444	2000	1265-1320	1035-1055	940-990	670-753	781-814	866-875	965-977	1110-1130	1243-1358
468	2000	1326-1390	1090-1110	992-1045	707-794	823-860	913-930	1018-1040	1170-1200	1310-1441
492	2000	1385-1425	1160-1165	1045-1090	742-830	865-925	958-1000	1070-1115	1232-1290	1500-1515
540	2000	1515-1555	1274-1280	1145-1200	814-890	949-990	1052-1070	1173-1195	1350-1390	1646-1663
576	2000	1616-1665	1359-1380	1225-1285	868-950	1012-1060	1122-1150	1251-1285	1440-1480	1755-1780
612	2000	1700-1765	1440-1480	1300-1370	924-1010	1076-1130	1193-1220	1330-1360	1531-1580	1865-1885
648	2000	1790-1865	1525-1570	1380-1445	977-1070	1138-1190	1261-1290	1407-1440	1619-1670	1974-1996
684	2000	1880-1960	1610-1680	1455-1525	1031-1130	1153-1260	1331-1360	1489-1520	1709-1765	2063-2107

Table 5-55: Protective Characteristics of Gapped Silicon-Carbide Intermediate Valve Arresters. Ref. ANSI/IEEE C62.2-1987, Table A2.
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Voltage Rating of Arrester (kV rms)	Impulse Sparkover Voltage		1.2/50-μs kV Crest (Range of Maxima)	Switching Surge Sparkover Voltage kV Crest (Range of Maxima)	Discharge Voltage for 8/20-μs Discharge Current Wave				
	Front-of-Wave				kV Crest for 1500A (Range of Maxima)	kV Crest for 3000A (Range of Maxima)	kV Crest for 5000A (Range of Maxima)	kV Crest for 10 000A (Range of Maxima)	kV Crest for 20 000A (Range of Maxima)
	Rate of Rise of Test Voltage (kV/μs)	kV Crest (Range of Maxima)							
3	25	11-12	11-12	-	5.2-7.5	6-8	6.6-9	7.5-10	8.7-12
6	50	21-21	19-19	-	10.4-13.5	11.9-14	13.2-15.5	15-17.5	17.4-20
9	75	31-33	27.5-32	-	15.6-21	17.9-23	19.8-25	22.5-28	26.1-31
12	100	38-42	35.5-37	-	20.8-27	23.8-29	26.4-32	30-34	34.8-37.5
15	125	47-51	43.5-46.5	-	25.9-34	29.7-36.5	32.9-39.5	37.5-43	43.5-47.5
21	175	67-73	58-64	-	36.3-47.5	41.6-51	46.1-56	52.5-60	60.9-66
24	200	75-78	66-75	-	41.5-54	47.6-58	52.7-64	60-68	69.6-75
30	250	91-97	81-91	-	51.8-68	59.4-73	65.8-79	75-86	87-95
36	300	108-116	95-103	-	62.2-82	71.3-87	79-95	90-102	104-113
39	325	116-126	102-110	-	67.4-91	77.3-97	85.5-106	97.5-114	113-126
48	400	143-154	121-132	-	83-109	95-116	105-127	120-136	139-150
60	500	166-190	147-155	185-206	104-136	119-145	131-159	150-171	174-189
72	600	201-230	171-191	219-245	124-163	143-174	158-191	180-204	209-225
90	750	250-283	223-233	274-304	155-204	178-218	197-239	225-256	261-282
96	800	268-300	236-250	292-323	166-217	190-232	211-254	240-273	278-300
108	900	283-335	258-265	328-362	187-244	214-261	237-286	270-307	313-338
120	1000	299-370	276-295	351-400	207-272	238-290	263-319	300-338	348-380

Table 5-56: Protective Characteristics of Gapped Silicon-Carbide Distribution Arresters. Ref. ANSI/IEEE C62.2-1987, Table A3.
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Voltage Rating of Arrester (kV rms)	Rate of Rise of Test Voltage (kV/μs)	Impulse Sparkover Voltage				Discharge Voltage for 8/20-μs Discharge Current Wave				
		Front of Wave		1.2/50 μs						
		Without External Gap kV Crest (Range of Maxima)	With External Gap kV Crest (Range of Maxima)	Without External Gap kV Crest (Range of Maxima)	With External Gap kV Crest (Range of Maxima)	kV Crest for 1500 A (Range of Maxima)	kV Crest for 3000 A (Range of Maxima)	kV Crest for 5000 A (Range of Maxima)	kV Crest for 10 000 A (Range of Maxima)	kV Crest for 20 000 A (Range of Maxima)
3	25	14-25	24-38	12-22	24-37	8-10	8.4-11.5	10-12.4	11.5-13.8	13.5-15.7
6	50	27-35	45-57	23-33	35-55	16-20	17-23	20-24	22.5-26	25-30
9	75	39-48	60-76	34-45	48-65	24-30	25-34	29-36.5	32.5-41	36-52
10	83.3	40-48	62-76	35-49	48-67	25-30	37.5-34	29.5-37	32.5-44	36-52
12	100	49-60	73-96	44-57	59-85	32-40	34-46	29.5-48	43-53	49-61.5
15	125	47-75	80-115	49-65	69-100	40-50	42-55	39-60	54-65.5	60-76
18	150	55-90	96-133	58-76	79-118	48-60	51-66	46-72	65-78	71-91
21	175	63-90	110-139	66-78	-123	56-70	59-75	68-80.5	73-90	82-103
27	225	79-102	-	75-98	-	70-80	76-86	82-94	90-105	99-121
30	250	86-114	-	81-100	-	76-89	84-97	91-105	100-116	111-134

Test requirements for metal oxide surge arresters are listed in IEEE Std. C62.11. Table 5-57 indicates the maximum continuous operating voltage (MCOV) and duty-cycle ratings for surge arresters. The application of metal oxide surge arresters is described IEEE Std. C62.22. The major protective characteristics of metal oxide arresters are summarized in Table 5-58.

Table 5-57: Metal Oxide Arrester Ratings in (kV) rms.
Ref. IEEE C62.11-1993, Table 1.
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Duty-Cycle Voltage	MCOV	Duty-Cycle Voltage	MCOV
3	2.55	132	106
6	5.10	144	115
9	7.65	168	131
10	8.40	172	140
12	10.20	180	144
15	12.70	192	152
18	15.30	228	180
21	17.00	240	190
24	19.50	258	209
27	22.00	264	212
30	24.40	276	220
36	29.00	288	230
39	31.50	294	235
45	36.50	312	245
48	39.00	396	318
54	42.00	420	335
60	48.00	444	353
72	57.00	468	372
90	70.00	492	392
96	76.00	540	428
108	84.00	564	448
120	98.00	576	462
		588	470
		612	485

NOTE: For ratings not shown, consult with the manufacturer.

Table 5-58: Metal Oxide Station- and Intermediate-Class Arrester Characteristics. Ref. IEEE C62.22-1991, Table 1.
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				Station Class					
Steady-State Operation System Voltage and Arrester Ratings				Protective Levels Range of Industry Maxima Per Unit—Crest of MCOV			Durability Characteristics (IEEE Std C62.11-1987 [9])		
Maximum System Voltage L-L (kV/rms)	Maximum System Voltage L-G (kV/rms)*	Minimum MCOV Rating (kV/rms)	Duty Cycle Ratings (kV/rms)	0.5 μs FOW Discharge Voltage (DV) (NOTE 1)	8/20 μs wave DV (NOTE 1)	Switching Surge—DV (NOTE 2)	High-Current Withstand Crest (Amperes)	Transmission Line Discharge (Miles)	Pressure Relief (A rms) (Symmetrical) (NOTE 3)
4.37	2.52	2.55	3-	2.32-2.48	2.10-2.20	1.70-1.85	65 000	150	40 000-65 000
8.73	5.04	5.1	6-9	2.33-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
13.1	4.56	7.65	9-12	2.33-2.48	1.79-2.23	1.70-1.85	65 000	150	40 000-65 000
13.9	8.00	7.65	9-15	2.33-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
14.5	8.37	8.4	10-15	2.33-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
26.2	15.12	15.3	18-27	2.33-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
36.2	20.92	22	27-36	2.43-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
48.3	27.89	29	36-48	2.43-2.48	1.97-2.23	1.70-1.85	65 000	150	40 000-65 000
72.5	41.86	42	54-72	2.19-2.40	1.97-2.18	1.64-1.84	65 000	150	40 000-65 000
121	69.86	70	90-120	2.19-2.40	1.97-2.18	1.64-1.84	65 000	150	40 000-65 000
145	83.72	84	104-144	2.19-2.39	1.97-2.17	1.64-1.84	65 000	150	40 000-65 000
169	97.57	98	120-172	2.19-2.39	1.97-2.17	1.64-1.84	65 000	175	40 000-65 000
242	139.72	140	172-240	2.19-2.36	1.97-2.15	1.64-1.84	65 000	175	40 000-65 000
362	209.00	209	258-312	2.19-2.36	1.97-2.15	1.71-1.85	65 000	200	40 000-65 000
550	317.54	318	396-564	2.01-2.25	2.01-2.25	1.71-1.85	65 000	200	40 000-65 000
800	461.88	462	576-612	2.01-2.25	2.01-2.25	1.71-1.85	65 000	200	40 000-65 000
				Intermediate Class					
4.37-169	2.52-97.67	2.8-98	3-144	2.38-2.85	2.28-2.55	1.80-2.10	65 000	100	16100 (NOTE 3)

* Voltage range A, ANSI C84.1-1989 [1].

NOTE 1:   Equivalent FOW producing a voltage wave cresting in 0.5 μs. Protective level is maximum DV for a 10 kA impulse current wave on arrester duty cycle rating through 312 kV, 15 kA for duty cycle ratings 396-564 kV, and 20 kA for duty cycle ratings 576-612 kV, per IEEE Std. C62.11-1987 [9].

NOTE 2:   Switching surge characteristics based on maximum switching surge classifying current (based on an impulse current wave with a time to actual crest of 45 μs to 60 μs) of 500 A on arrester duty cycle ratings 3-108 kV, 1000 A on duty cycle ratings 120-240 kV, and 2000 A on duty cycle ratings above 240 kV, per IEEE Std. C62.11-1987 [9].

NOTE 3:   Test values for arresters with porcelain tops have not been standardized.

Relative protective capabilities and initial costs of surge arresters, in descending order, are station-class, intermediate-class, and finally distribution-class arresters. The appropriate arrester has to be determined from an analysis of the protective characteristics required, the importance of the equipment protected, the level of reliability desired, and the overall cost of protection.

Refer to RUS IP 202-1 for a listing of surge arresters that may be used in the cooperative's substations.

5.8.2.1   Station Class Arresters: Station-class arresters are more ruggedly constructed than those in either the intermediate or distribution class. They have greater surge current discharge ability and lower IR voltage drop, thus affording better protection. In the event of arrester failure, their ability to vent safely during high system short-circuit currents is better than the other classes of arresters.

Station-class arresters are recommended for all substations of large capacity (10,000 kVA and above) and on smaller substations that are of prime importance. They should be applied on transmission circuits longer than approximately 100 miles or where shunt capacitor banks are installed.

Station-class arresters are also desirable on substations using reduced insulation (BIL) or those located in high lightning exposure areas. They should be used where the system short-circuit current exceeds the venting capability of intermediate-class arresters. They are the only class of arrester available for use on systems above 150 kV.

5.8.2.2   Intermediate Class Arresters: Intermediate-class arresters may be used in substations rated below 10,000 kVA at a cost saving when compared to station-class arresters. Their electrical protective characteristics (sparkover and IR) are higher than station-class arresters, but are usually adequate for small substations. In the event of arrester failure, intermediate-class arresters can safely vent with short-circuit current of 16,000 amperes or less. Intermediate-class arresters are available in ratings 3 kV through 120 kV.

5.8.2.3   Distribution-Class Arresters: Distribution-class arresters may be used on the low-voltage side of distribution substations. Install them on the load side of feeder overcurrent protective devices (reclosers or breakers). They are frequently applied connected to the low-voltage bushings of small distribution substation transformers. Their protective characteristics are not as good as either intermediate- or station-class arresters. If distribution-class arresters are used in substations, use only the direct-connected type with ground lead disconnector (isolator).

5.8.3 Ratings (Standard Definitions)

5.8.3.1   Voltage Rating–Duty Cycle (kV rms): The designated maximum permissible operating voltage between its terminals at which an arrester is designed to perform its duty cycle. It is the voltage rating specified on the nameplate. This rating is applicable specifically to the silicon-carbide valve arrester and is also typically listed with the MCOV rating for the metal oxide arrester.

5.8.3.2   Power-Frequency Sparkover Voltage: The root-mean-square value of the lowest power frequency sinusoidal voltage that will cause sparkover when applied across the terminals of an arrester. This rating is applicable to the silicon-carbide valve arrester.

5.8.3.3   Impulse Sparkover Voltage: The highest value of voltage attained by an impulse of a designated wave shape and polarity applied across the terminals of an arrester prior to the flow of discharge current. This rating is applicable to the silicon-carbide valve arrester.

Standard wave shape is a 1.2 x 50 μs wave, i.e., a wave that rises to crest in 1.2 μs and decays to one-half crest value in 50 μs.

5.8.3.4   Maximum Continuous Operating Voltage (MCOV): The maximum continuous operating voltage is the maximum rms power frequency operating voltage that may be applied continuously to the terminals of the arrester. When applying metal oxide surge arresters, the minimum value of this voltage is usually the maximum system line-to-ground voltage.

5.8.3.5   Discharge Current: The discharge current is the current that flows through an arrester as a result of a surge.

5.8.3.6   Discharge Voltage: The voltage that appears across the terminals of an arrester during the passage of discharge current. Maximum values are usually available from the manufacturer for currents of 1.5, 3, 5, 10, 20, and 40 kA with a wave shape of 8 x 20 μs. The discharge voltage resulting from a standard 8 x 20 μs current wave shape approximates the standard 1.2 x 50 μs voltage wave shape reasonably well between the current magnitudes of 5 kA and 20 kA.

The 8 x 20 μs standard current wave shape is one that rises to crest in 8 μs and decays to one-half crest value in 20 μs. The 1.2 x 50 μs voltage wave shape is one that rises to crest in 1.2 μs and decays to one-half crest value in 50 μs.

5.8.3.7   Discharge-Voltage Current Characteristic: The discharge-voltage current characteristic is the variation of the crest values of discharge voltage with respect to discharge current.

5.8.4 System Voltage

System voltages carry two designations: nominal voltage and maximum system voltage.

5.8.4.1   Nominal Voltage: Nominal voltage is the approximate phase-to-phase voltage distinguishing one system from another. The nominal voltage is the voltage by which the system may be designated and is near the voltage level at which the system normally operates. The nominal voltage is usually approximately 5 to 10 percent below the maximum system voltage.

5.8.4.2   Maximum System Voltage: Maximum system voltage is the highest rms phase-to-phase operating voltage that occurs, the highest phase-to-phase voltage for which equipment is designed for satisfactory continuous operation without derating of any kind. It is the starting basis on which surge arresters are applied.

Maximum system voltages are generally those prescribed in ANSI Std. C84.1, "Voltage Ratings for Electric Power Systems and Equipment (60 Hz)." On systems rated 345 kV and below, it is expected that the maximum system voltage may be 5 to 10 percent higher than nominal voltage.

5.8.5 Grounded vs. Ungrounded Systems

Systems have been historically referred to as effectively grounded when coefficient* of grounding (COG) does not exceed 80 percent, or noneffectively grounded or ungrounded when coefficient* of grounding exceeds 80 percent.

> *The coefficient of grounding (COG) is the ratio of E_{LG}/E_{LL}. The COG is expressed as a percentage of the highest root-mean-square line-to-ground power-frequency voltage, E_{LG}, on a sound phase, at a selected location, during a fault to ground affecting one or more phases to the line-to-line power-frequency voltage, E_{LL}, that would be obtained, at the selected location, with the fault removed.

A COG value not exceeding 80 percent is obtained approximately when, for all system conditions, the ratio of zero sequence reactance to positive sequence reactance (X0/X1) is positive and less than three, and the ratio of zero-sequence resistance to positive-sequence reactance (R0/X1) is positive and less than one.

On certain distribution systems of the four-wire type where transformer neutrals and neutral conductors are directly grounded at frequent points along the circuit, the positive sequence resistance (R) may be significant due to small conductors and should be considered.

Neglecting the resistance component may result in higher rated arresters than normally required. In these cases, use ratios R0/Z and X0/Z1. The COG for such systems may be as low as 67 percent. On many high-voltage transmission systems, the COG may be as low as 70 percent. Recognize the possibility of increases in the COG due to system switching or changes.

ANSI/IEEE Std. C62.92, "IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems Part I—Introduction," provides a more detailed and thorough discussion of the effects of grounding and the calculation of the COG.

5.8.6 Application Guide for Silicon-Carbide Valve Arresters

5.8.6.1   General: The voltage rating assigned to a surge arrester should exceed the maximum 60 Hz voltage across its terminals during normal or fault conditions. In general, the surge arrester voltage rating should be at least 25 percent higher than the phase-to-ground voltage when the system is operating at maximum phase-to-phase voltage.

On an isolated neutral system, which may be a delta system or an ungrounded-wye system, this rating should be approximately 105 percent of, and never less than, the maximum rating of the system. Such an arrester is called a "full-rated" or 100 percent arrester. On effectively grounded systems, the arrester maximum rating can generally be 80 percent or less of the maximum system voltage. In special cases, arresters as low as 75 percent or even 70 percent of maximum system voltage rating may be applied, depending on the coefficient of grounding of the system.

5.8.6.2   Maximum Phase-to-Ground Voltage: The first step recommended in selecting a lightning arrester is to determine the maximum phase-to-ground power-frequency overvoltage at the arrester location. This maximum overvoltage may occur as a result of a fault condition, sudden loss of load, or resonance. Overvoltages experienced as a result of loss of load or resonance are determined by system operating experience or by computer studies. Overvoltages that result from these two conditions are not expected to be significant for most applications at 230 kV and below.

At 345 kV, the switching surge protection level may be more significant than the lightning impulse protection level. At the higher voltage level, capacitance of the line will be more significant. On any long line, the voltage of the line will increase over distance. With the line energized during switching operations from one end of the line only, the remote end will experience a voltage increase. In addition, if

the energizing source is a relatively weak source, the line could experience transient oscillations resulting in additional voltage increase. The additional line capacitance will tend to make the line more susceptible to transients than the lower voltage lines. Switching of a 345 kV line terminated with a transformer could result in transients if resonance conditions are present. These conditions could result in the overstressing of surge arresters due to multiple restrikes through the arrester. Transient network analysis (TNA) or electromagnetic transient program analysis (EMTP) may be necessary to determine the size of the arrester to be applied. The study could also determine other means to control transient overvoltage conditions such as the application of reactors, pre-insertion resistors, or specific operating practices to be followed during switching.

Determination of the overvoltage due to a fault condition is necessary for any power system where less than full line-to-line rated arresters are to be considered. The maximum line-to-line voltage at the point of arrester application multiplied by the COG based on a fault at the arrester location will often result in the maximum voltage to be applied. This may vary, however, depending on the system configuration. The application of neutral impedance elements may shift the location of the maximum voltage on a line with the shift of the transformer neutral during a phase-to-ground fault.

The COG may be estimated using the graphs of Figure 5-33 or calculated from system values. When calculating the COG for use with machines, the subtransient reactance of the machine is recommended for use. With EHV systems, consider the effects of shunt reactors, capacitance, series capacitance, or reactors when applicable.

5.8.6.3   Protective Margins: The lower the arrester rating on a given system, the greater the protective margin for the insulation of the protected equipment. When system studies or calculations show that protective margins would be more than adequate, the BIL of major equipment may be reduced for substantial savings. Generally, the accepted practice is to provide a minimum margin of 20 percent between transformer BIL and surge arrester maximum IR, and 15 percent in the case of switching surges. The switching surge withstand strength of transformer insulation is usually specified at 83 percent of impulse BIL. Greater margins may be required where a condition of insulation degradation may be present.

Examine the protective margins over the full volt–time characteristics of the insulation that is to be protected and the volt–time characteristics of the arrester. Also maintain sufficient margin regardless of the relative physical location of the arrester and protected equipment in the substation. Locate the arrester as close to the major equipment as possible, and the arrester ground resistance should be low. Connect surge arrester grounds reliably to the substation ground grid and with the frames of all equipment being protected.

5.8.6.4   Thermal Capacity: The arrester thermal capacity or ability to pass repeated or long-duration surge currents (such as switching surges) without an internal temperature rise, which could fail the arrester, has to be checked. This is especially true in all cases where there are long lines or shunt capacitor banks with high stored energy. Available switching surge energy increases as the square of the system voltage and directly with the length of lines. Thus, on 138 kV lines of equal length to 69 kV lines, the surge arresters have to have at least four times the discharge capacity.

5.8.6.5   Direct Stroke Shielding: Surge arresters are applied primarily based on their effectiveness in limiting overvoltages in the form of traveling waves entering the substation over connecting lines. High-energy lightning strokes hitting a substation bus at or near the arrester could easily destroy the arrester while it is attempting to pass the surge current to ground. Even if the arrester is not destroyed, the
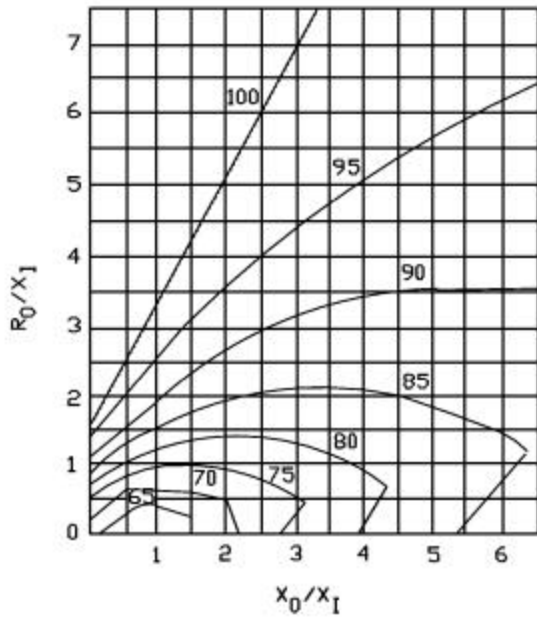
(A)

VOLTAGE CONDITIONS NEGLECTING POSITIVE-
AND NEGATIVE- SEQUENCE RESISTANCE. $R_1 = R_2 = 0$
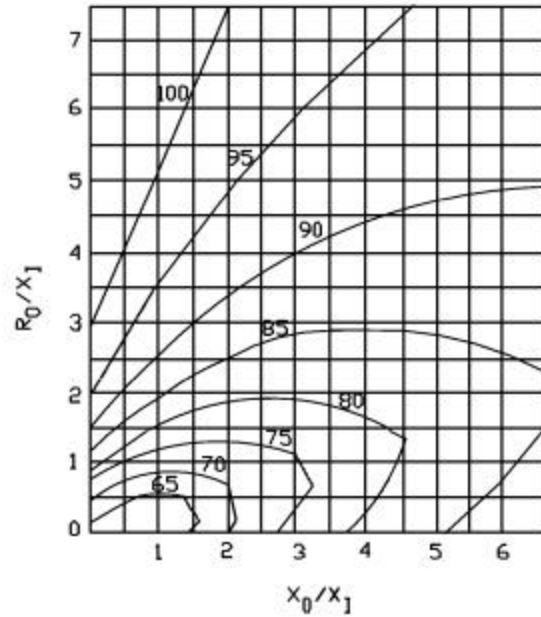
(C)

VOLTAGE CONDITIONS FOR $R_1 = R_2 = 0.2\ X_1$
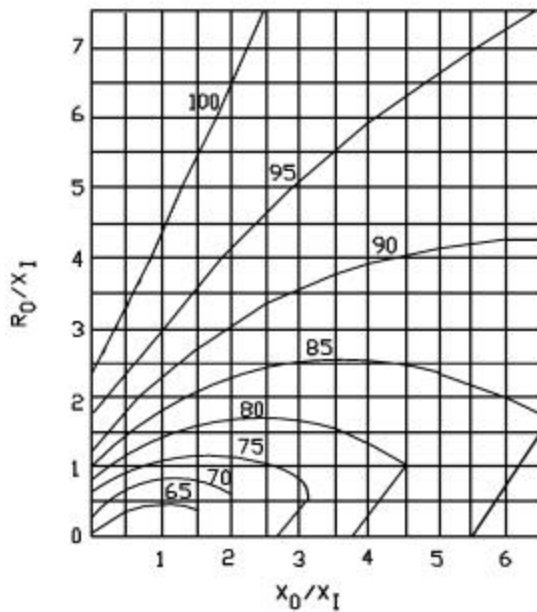
(B)

VOLTAGE CONDITIONS FOR $R_1 = R_2 = 0.1\ X_1$

NOTE: NUMBERS ON CURVE INDICATE COEFFICIENT OF GROUNDING FOR ANY TYPE OF FAULT FOR ARRESTERS BOUNDED BY CURVE AND AXES OF THE CURVES. ALL IMPEDANCE VALUES MUST BE ON THE SAME kVA BASES OR IN OHMS ON SAME VOLATAGE BASE.

FOR ALL CURVES:

R_0 = ZERO-SEQUENCE RESISTANCE
R_1 = POSITIVE-SEQUENCE RESISTANCE
R_2 = NEGATIVE-SEQUENCE RESISTANCE
X_0 = ZERO-SEQUENCE INDUCTIVE REACTANCE
X_1 = POSITIVE-SEQUENCE SUBTRANSIENT REACTANCE
X_2 = NEGATIVE-SEQUENCE REACTANCE
$X_1 = X_2$

THE EFFECT OF FAULT RESISTANCE WAS TAKEN INTO ACCOUNT. THE RESISTANCE THAT GIVES THE MAXIMUM VOLTAGE TO GROUND WAS THE VALUE USED. THE DIS-CONTINUITY OF THE CURVES IS CAUSED BY THE EFFECT OF FAULT RESISTANCE.

THESE DATA ARE FROM TRANSMISSION AND DISTRIBUTION REFERENCE BOOK. WESTINGHOUSE ELECTRIC CORP. PITTS-BURG. PA., 1950.

Figure 5-33: Coefficient of Grounding for Various System Conditions. Ref. IEEE C62.2, Figure 2.
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protective margins provided may become nonexistent as a result of the effect of the steep fronts and high IR voltage produced by the arrester.

Therefore, a basic principle of surge arrester application is the provision of overhead ground wires and/or grounded conducting masts to shield substation electrical equipment against direct lightning strokes. Effective shielding also permits greater separation of a surge arrester from the equipment being protected since the overvoltage impulses are less steep and are usually of lower magnitude.

5.8.6.6   Multiple Lines: It is well recognized that the severity of a lightning impulse arriving at a substation is reduced by the effect of multiple lines. Traveling waves coming into a substation will divert part of the energy in the wave over all line connections. It is difficult, however, to take full advantage of this since one cannot be sure the lines will be connected when needed. In addition, in substations with long buses, etc., the distances sometimes prevent effective use of this principle.

5.8.6.7   Standards and Guides: There are two principal national standards or guides pertaining to silicon-carbide valve surge arresters: IEEE Stds. C62.1 and C62.2.

5.8.6.7.1 IEEE C62.1, "IEEE Standard for Gapped Silicon-Carbide Surge Arresters for Alternating-Current Power Circuits." This standard contains much basic information on arresters such as definitions, service conditions, classification and voltage ratings, performance characteristics and tests, test procedures, design tests, conformance tests, and construction. Some pertinent sections are as follows:

   a.   Section 4, Service Conditions.
   b.   Standard arresters are designed for ambient temperatures not exceeding 40°C (104°F) and altitudes not exceeding 1800 meters (6000 feet).
   c.   Section 5.1, Table 1 (see Table 5-52), Voltage in Kilovolts, lists the standard voltage ratings available in distribution-, intermediate-, and station-class arresters.
   d.   Section 7.2, Table 2, Test Requirements for Arrester Classification, summarizes the sections dealing with test requirements for the different arrester classifications: distribution, intermediate, and station.
   e.   Section 8.1, Table 3, Insulation Withstand Test Voltages, lists the various insulation requirements of all ratings of the different arrester classifications, with the internal parts removed.
   f.   Section 8.9, Table 5 (see Table 5-53), Pressure-Relief Test Currents for Station and Intermediate Arresters, lists the symmetrical rms amperes short-circuit capability of various ratings of station and intermediate arresters.

5.8.6.7.2   A guide for application of valve-type lightning arresters for alternating-current systems can be found in ANSI/IEEE Std. C62.2. This standard is an excellent guide on application of arresters. It contains information on general procedures; systematic procedures for protection of transformers and substation equipment; and protection of other equipment such as booster transformers, reactors, current transformers, etc. Of particular interest is the Typical Voltage–Time Curve for Coordination of Arrester Protective Levels with Insulation Withstand Strength (see Figure 5-34). This curve illustrates the protection provided by an arrester to transformer insulation.

Appendix A to IEEE Std. C62.2, Protective Characteristics of Surge Arresters, contains data on protective characteristics of available arresters compiled from domestic manufacturers. This is very useful for general studies, but it should be kept in mind that the voltage values given are the maximums of the
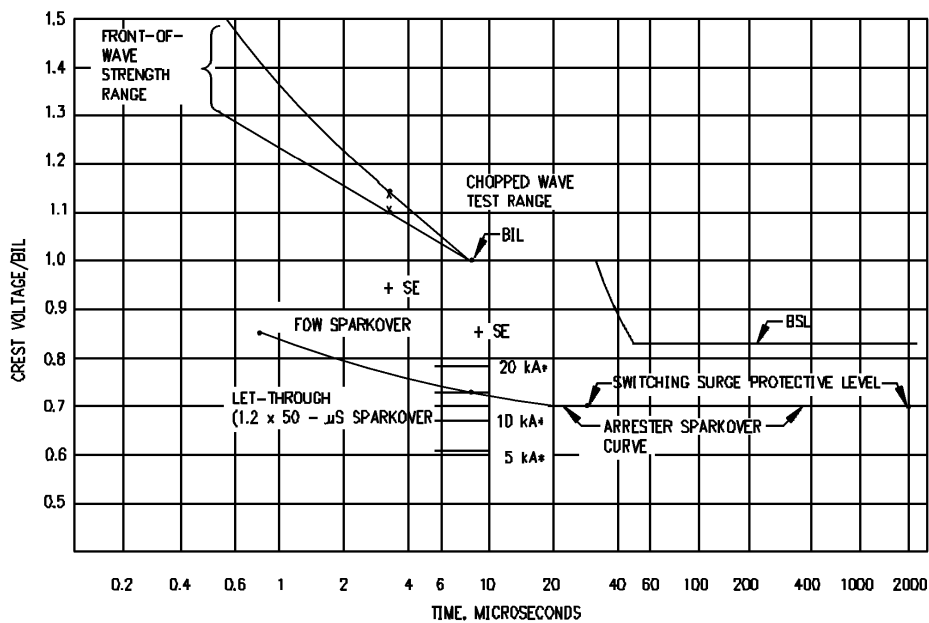
*DISCHARGE LEVEL FOR AN 8 x 20-μS TEST WAVE.

NOTES:

(1) FOR THE TRANSFORMER CURVE, PLOT FOUR POINTS FOR THE FOLLOWING WITHSTAND VOLTAGES AS OBTAINED FROM THE MANUFACTURER OR STANDARDS: (A) FRONT OF WAVE (IF AVAILABLE), (B) CHOPPED WAVE, (C) FULL WAVE (BIL) AT ABOUT 8 μS, AND (D) SWITCHING SURGE AT ABOUT 300 μS. CONNECT THE POINTS WITH A DOTTED OR DASHED LINE SHOWING DISJOINTED CURVES AT THE CHOPPED-WAVE POINT EXTENDING THE FULL-WAVE VOLTAGE AS A STRAIGHT LINE FROM ABOUT 8 TO 50 μS AND THE SWITCHING SURGE WITHSTAND VOLTAGE AS A STRAIGHT LINE EXTENDING FROM APPROXIMATELY 50 TO 2000 μS AND PASSING THROUGH THE PLOTTED 300-μS POINT. IT IS NOT POSSIBLE TO INTERPOLATE EXACTLY BETWEEN POINTS ON THE CURVE. GOOD EXPERIENCE HAS BEEN OBTAINED WITH THE ASSUMPTIONS IMPLICIT IN THE PRECEDING RULES: (A) THE FULL BIL STRENGTH WILL APPLY FOR FRONT TIMES BETWEEN 8 AND 50 μS. (B) MINIMUM SWITCHING SURGE WITHSTAND OCCURS BETWEEN 50 AND 2000 μS.

(2) FOR THE ARRESTER CURVE, APPROXIMATE THE SPARKOVER CURVE AS FOLLOWS: (A) PLOT THREE POINTS FOR THE FOLLOWING PUBLISHED SPARKOVER VOLTAGES FOR THE SPECIFIC ARRESTERS TO BE INSTALLED: FRONT OF WAVE, 1.2/50-μS SPARKOVER (AT 8 μS), AND SWITCHING SURGE PROTECTIVE LEVEL AS A STRAIGHT LINE FROM ABOUT 30 TO 2000 μS. CONNECT THE POINTS WITH A CURVE OF APPROXIMATELY THE SHAPE SHOWN. IF A MANUFACTURER'S VOLTAGE-TIME SPARKOVER CURVE IS AVAILABLE, IT MAY BE USED INSTEAD OF THE APPROXIMATION. (B) DRAW A LADDER OF LINES, EACH EXTENDING FROM 5 μS TO 10 μS AT LEVELS CORRESPONDING TO 5 kA, 10 kA, AND 20 kA DISCHARGE VOLTAGE. ADD A SIMILAR LINE PASSING THROUGH THE 1.2/50-μS SPARKOVER.

(3) TO USE THE CURVE:
(A) LOCATE THE POINT BETWEEN 0.5 AND 50 μS WHERE THE SEPARATION BETWEEN WITHSTAND AND ARRESTER CURVE(S) IS MINIMUM. (TREAT 1.2/50-μS SPARKOVER AND SELECTED DISCHARGE kA LINES AS SEPARATE CURVES.) CALCULATE PM=[(WITHSTAND VOLTAGE)/(ARRESTER VOLTAGE) - 1] * 100. PM MUST BE ≥ 20 AT THIS POINT. WHEN SEPARATION EFFECT HAS BEEN EVALUATED, PM MUST BE ≥ 15%.

(B) MAKE A SIMILAR CHECK BETWEEN 50 AND 2000 μS. PM MUST BE ≥ 15%.

(C) IF SEPARATION IS SIGNIFICANT (SEE 3.7.1.3), EVALUATE VOLTAGE AT PROTECTED EQUIPMENT (APPENDIX C). PLOT POINT AT 3 μS IF SPARKOVER OCCURS IN LESS THAN 2 μS; OTHERWISE, PLOT AT 8 μS.

Figure 5-34: Typical Voltage–Time Curve for Coordination of Arrester Protective Levels with Insulation Withstand Strength for Liquid-Filled Transformers.
Ref. IEEE Std. C62.2-1987, Figure 3. Copyright © 1987. IEEE. All rights reserved.

published protective characteristics. Consult specific manufacturer's information for more accurate insulation coordination.

Appendix B to IEEE Std. C62.2, Surge Arrester Applications for EHV Systems, provides important considerations concerning switching surges. It is generally necessary to consider switching surge protective levels only for application on systems above 69 kV. In most cases, insulation coordination levels will not be affected by switching surges except at levels at 345 kV or above.

5.8.6.8   Guide Steps for Application of Valve-Type Surge Arresters for AC Systems (see IEEE Std. 62.2): An example of surge arrester selection will be worked out along with each guide step to illustrate the procedure. The example is arrester selection for a 230 kV substation coordinated with the transformer BIL. The 230 kV substation is supplied by one 230 kV line. Both the substation and the line are effectively shielded.

5.8.6.8.1 Determine the maximum phase-to-ground temporary overvoltage at the arrester location. In most cases, this will depend on the coefficient of system grounding.

Example: At the surge arrester location, system parameters are known to be:

$$Rl = R2 = 0.1*X1, \quad R0/X1 = 0.8, \quad \text{and} \quad X0/X1 = 2.5$$

From curve (B) of Figure 5-33, the coefficient of grounding is 75 percent. Maximum system voltage is 230 kV x 1.05 or 242 kV. Maximum phase-to-ground overvoltage during a ground fault is 242 kV x 0.75 or 181 kV. No other conditions including switching configurations are considered to result in temporary overvoltages that will exceed this voltage level.

5.8.6.8.2 Estimate the waveshape and magnitude of arrester discharge current. The magnitude is determined largely by the effectiveness of the shielding against direct lightning strokes.

Example: The standard arrester discharge current curve (a 8 x 20 μs wave) represents the most severe current waveshape to be expected at a substation that is effectively shielded. Surge arrester discharge voltage characteristics (IR drop) are based on this standard curve. A conservative value of maximum current with effective shielding is 10 kA. The current could reach as high as 20 kA or higher if the substation is not effectively shielded.

5.8.6.8.3 Tentatively select arrester class and voltage rating.

Example: A station-class surge arrester has to be selected since this is the only type available at this voltage level. The substation size and importance may indicate a station-class arrester regardless of system voltage. Arrester voltage rating has to be at least 181 kV, as determined in Step 1. Another rule of thumb recommends that the arrester voltage rating be not less than 125 percent of the voltage to ground when the system is operating at maximum system voltage:

$$1.25 \text{ x } 1.05 \text{ x } 230 \text{ kV}/\sqrt{3} = 174 \text{ kV}$$

The next standard arrester rating above 174 kV and 181 kV is 192 kV. Therefore, 192 kV is selected as the tentative arrester rating.

5.8.6.8.4   Determine the impulse and switching surge protective levels of the tentatively selected arrester. The necessary information may be obtained from the arrester manufacturer or approximately from Appendix A of IEEE Std. 62.1 (see Table 5-53).

Example: Typical surge arrester characteristics are obtained from the arrester manufacturer's published data. These characteristics include maximum sparkover (S.O.) on front of wave; maximum S.O. on full wave of 1.2 x 50 μs; maximum S.O. on switching surge (S.S.), maximum discharge voltage for 5, 10, and 20 kA of discharge current; and minimum S.O. on 60 Hz voltage. Typical characteristics are shown plotted on Figure 5-34.

Calculate the maximum theoretical surge voltages that could appear at the insulation to be protected. These will depend on many factors, such as effectiveness of shielding, number of lines normally connected, and relative location of an arrester to protected equipment.

Example: For most applications, it is sufficient to rely on the recommended minimum margins between protection levels provided by the surge arrester and the BIL of the protected equipment. See Section 5.8.6.8.5.

Calculate the minimum permissible withstand strength of the insulation to be protected. The necessary information may be obtained from manufacturers of the equipment.   Approximate information may be obtained from applicable standards on the type of equipment.

Example: The impulse withstand strength of equipment is defined by its full-wave impulse test voltage using a standard 1.2 x 50 μs wave. The strength is greater for shorter duration voltage peaks. See Figure 5-35 for curves showing withstand strength of a power transformer over the range of 0 to 5,000 μs.

5.8.6.8.5   Evaluation of Insulation Coordination: (Front of Wave 20 percent; maximum discharge 20 percent; maximum switching surge 15 percent.)

Example: See Figure 5-35 for the coordination of surge arrester protective levels with 230 kV transformer BIL. Possible BILs of 900, 825, 750, and 650 kV are shown. All BILs are adequately protected from impulses or switching surges. However, other factors have to be considered such as 60 Hz withstand, both internal and external; future deterioration of the insulation; surge arrester location with respect to the transformer; etc. A BIL of 750 kV would appear to be a proper choice based on the conditions assumed. The surge arrester voltage rating of 192 kV is a proper selection unless there are unusual system conditions that could subject the arrester to voltages above its rating.

5.8.6.8.6   Insulation Coordination Calculation Iterations: When coordination cannot be achieved, the solution may be to select a different arrester, improve arrester location relative to protected equipment, increase the insulation level of protected equipment, improve shielding, or install additional arresters.

5.8.6.8.7   Transformer Arrester Rating Coordination: When the transformer high-voltage side arrester has been chosen, compare the rating on a per unit basis to the arrester rating for the low-voltage winding. The arrester applied to the low voltage of a transformer should have a rating slightly higher than the rating of the high-voltage winding. An impulse that hits the high-voltage winding will also be transformed to the low-voltage winding via the transformer turns ratio with the corresponding voltage and current. If the energy is discharged through the low-voltage winding arresters, the current discharged through the low-voltage winding arresters will be the transformer turns ratio times the high-voltage arrester discharge

Figure 5-35: Typical Volt–Time Curves for Coordination of Metal Oxide Surge Arrester Protective Levels with Insulation Withstand Strength

current. Make sure that energy will discharge through the high-voltage winding arresters before it will discharge through the low-voltage winding arresters.

5.8.7 Application Guide for Metal Oxide Surge Arresters

Metal oxide arresters were developed after the application of silicon-carbide valve arresters to electric power systems. The primary component of the arrester that differentiates metal oxide arresters from the previous arresters is the zinc oxide valve that has significantly greater non-linear volt – current characteristics as compared to previous devices. The zinc oxide valve operates more closely to that of a zener diode that is applied in the electronic industry. The valve is capable of being applied without any gaps in the design, eliminating the sparkover characteristic of previous arresters (see Figure 5-36) as it eases into conduction. The zinc oxide valve typically provides lower discharge voltages than available with previous designs.
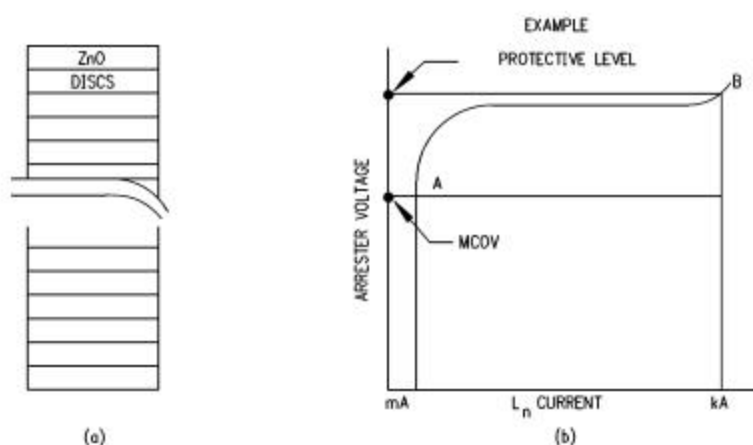
Figure 5-36: Gapless Metal Oxide Surge Arrester. Ref. IEEE Std. C62.22-1991, Figure 1.
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5.8.7.1   **Types of Metal Oxide Surge Arresters:** In addition to the silicon-carbide station, intermediate, and distribution classes of arresters, development of the metal oxide arrester has produced three basic categories of arresters. These categories are known as the gapless, shunt-gapped, and series-gapped metal oxide arresters.

5.8.7.1.1   Gapless Metal Oxide Surge Arresters: Gapless arresters consist of a stack or multiple stacks of metal oxide disks (see Figure 5-36). Above the MCOV rating, the arrester exhibits a very non-linear behavior. This arrester is applied directly to the line terminal and ground with only its inherent impedance limiting the amount of leakage current through the arrester.

5.8.7.1.2   Shunt-Gapped Metal Oxide Surge Arresters: Shunt-gapped metal oxide arresters consist of a stack of metal oxide disks that are bridged by shunt gaps (See Figure 5-37). When the disks start to conduct current upon the arrival of a surge, the discharge voltage will increase to the point where the gaps will spark over and short the associated disks. The sparkover of the gaps, typically at several hundred amps (range B to C), has the effect of reducing the discharge voltage of the arrester (range D to E). A decrease in the amount of discharge current will eventually extinguish the gap current, causing the voltage to increase to its initial curve, A-B-C.
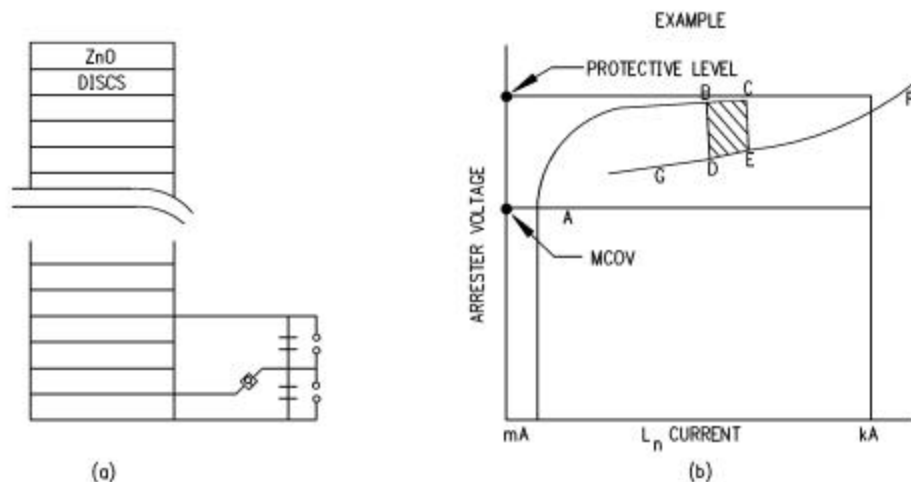
Figure 5-37: Shunt-Gapped Metal-Oxide Surge Arrester.
Ref. IEEE Std. C62.22-1991, Figure 2.
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5.8.7.1.3   Series-Gapped Metal Oxide Surge Arresters: The series-gapped metal oxide arresters use fewer disks in series with a series gap impedance network (see Figure 5-38). As the arrester starts to conduct, the voltage is divided between the disks and the gap network. When the voltage across the gapped impedance network increases to the point the gap sparks over, the voltage is reduced across the total arrester to be that which is across the metal oxide disks.
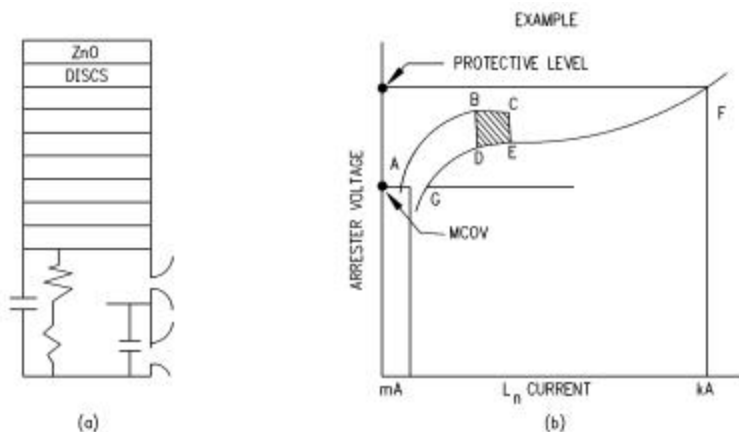
Figure 5-38: Series-Gapped Metal Oxide Surge Arrester.
Ref. IEEE Std. C62.22-1991, Figure 3.
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The application of metal oxide surge arresters is similar to the application of silicon-carbide arresters in terms of the system information that is required. The system parameters of the maximum system operating voltage and temporary overvoltages are of primary importance in the application of this type of arrester. The discharge current levels are also important to the application of this arrester.

5.8.7.2   **Operating Conditions:** Usual operating conditions for surge arresters include continuous air temperature ratings between –40°C and +40°C with maximum air temperatures of +60°C at elevations less than 1800 meters (6000 ft). Unusual operating considerations could include operation in enclosed

areas or in areas contaminated by gas fumes or external air contamination. Confirm special operating conditions with the manufacturer before the applications are made.

5.8.7.3   Maximum Phase-to-Ground Voltage

5.8.7.3.1   Maximum Continuous Operating Voltage: Metal oxide arresters are applied primarily based on the MCOV. Metal oxide arresters have been assigned dual voltage ratings based on the conventional duty-cycle rating and the newer MCOV rating (see Table 5-57). Of primary importance is the requirement that the MCOV of the applied arrester be above the maximum continuous operating voltage of the electric system. For a solidly grounded system with the maximum operating allowance of 5 percent, the minimum MCOV is calculated using Equation 5-7:

> Equation 5-7
>
> $$MCOV_{(MIN)} \ = \ E_{LL} * k / \sqrt{3}$$

Where:
   k = Percentage of operating voltage allowance over the nominal operating voltage

For a 34.5 kV nominal voltage solidly grounded system with a 5 percent maximum operating voltage allowance, the MCOV is calculated as follows:

> $$34.5 \text{ kV} * 1.05 / \sqrt{3} = 21 \text{ kV}$$

According to Table 5-57, the nearest MCOV rating above this value is 22 kV. This would be the minimum rating of the arrester to receive consideration.

The application of arresters on ungrounded or impedance-grounded systems is normally applied on the basis of their associated duty-cycle rating. Using the arresters on the basis of 100 percent voltage application, the minimum duty-cycle rating for the arresters on an ungrounded system will be the maximum anticipated operating line-to-line voltage. For a 34.5 kV nominal voltage impedance-grounded or ungrounded system with a 5 percent maximum operating voltage allowance, the duty-cycle rating is calculated as follows:

> $$Rating = E_{LL} * k$$

Where:
   k = Percentage of operating voltage allowance over the nominal operating voltage

For a 34.5 kV system,

> $$34.5 \text{ kV} * 1.05 \ = 36.2 \text{ kV}$$

According to Table 5-57, the next highest duty-cycle voltage rating for the arrester is 39 kV. The corresponding MCOV for this arrester is 31.5 kV. With this MCOV rating, the arrester will move into conduction should one of the phases be grounded or be faulted. It then becomes a judgment of the engineer to assess the amount of time the arrester will be required to conduct under these conditions. Applying a metal oxide arrester under these conditions will make use of the inherent improved temporary overvoltage capabilities of the devices. Follow the manufacturer's recommendations regarding the extent of overvoltage capabilities for a particular arrester when applying arresters on this basis.

5.8.7.3.2 Maximum Phase-to-Ground Temporary Overvoltage (TOV) at the Arrester Location: In addition to the MCOV, any temporary operating voltages above the MCOV have to be considered for magnitude and duration. These conditions may arise due to conditions that include line-to-ground fault conditions, loss of neutral on a normally grounded system, sudden load rejection, oscillations due to system resonance, switching surges, switching conditions, etc.

Evaluate each of the conditions resulting in temporary overvoltage in terms of the effect it has on the system. The magnitude and duration of the overvoltage will assist in determining the proper application of the arresters. Metal oxide arresters have a significantly improved ability to operate during temporary overvoltages. Manufacturers typically publish curves to indicate the magnitudes and durations of overvoltages under which the arresters will successfully operate (see Figure 5-39). Apply the arresters within the limitations the manufacturer recommends for acceptable overvoltage within the manufacturer's specified time limits.
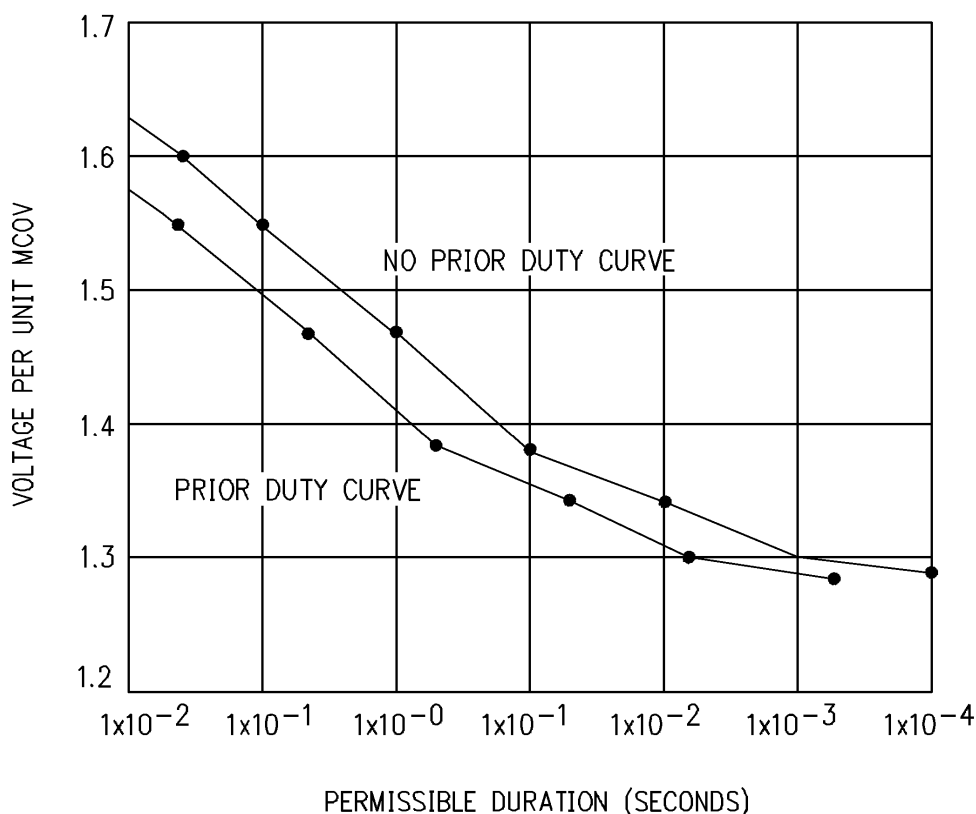
Figure 5-39: Typical 60-Hz Temporary Overvoltage Capability for Metal Oxide Arresters

Temporary overvoltages are most often associated with the overvoltages experienced by the unfaulted phases during a phase-to-ground fault. These overvoltages are determined in the same way as for silicon-carbide arresters. Other overvoltage conditions on higher voltage lines may require transient network analysis or similar studies to determine the actual parameters that are required.

5.8.7.4   Arrester Discharge Currents

5.8.7.4.1   Lightning Impulse Discharge Currents: The magnitude of discharge current is largely

determined by the effectiveness of the shielding against direct lightning strokes. Discharge currents of 5 kA to 20 kA are commonly used to calculate the maximum discharge voltage. This is covered in Section 5.8.6.8.4 for the silicon-carbide arresters. The same procedures are used here.

5.8.7.4.2 Switching Surge Impulse Currents: Switching surges are seldom a consideration below 345 kV. Accurate determination of surge withstand capabilities will require a transient network analysis or electromagnetic transient study to be performed. These studies can simulate the transmission system elements, including the arresters, determine the surge levels that are expected, and size the surge arresters based on the energy absorption characteristics of the arresters. Approximations of the surge currents can be made using Equation 5-8:

Equation 5-8

$$I_A = \frac{E_S - E_A}{Z}$$

Where:

I_A = Surge current (amps)
E_s = Surge voltage (volts)
E_A = Discharge voltage (volts)
Z = Line surge impedance (ohms)

5.8.7.5 Arrester Discharge Energy: Arrester discharge energy is estimated using Equation 5-9:

Equation 5-9

$$J = 2 L E_A I_A / c \qquad \text{(kilojoules)}$$

Where:

L = Distance of the transmission line
c = Speed of light at 190 miles per ms or 300 km/ms

Values of the surge current or the energy may be compared to the manufacturer's data regarding the surge discharge capability of the arresters.

5.8.7.6 Insulation Coordination: BILs, BSLs, and CWW levels for equipment are obtained from the equipment standards. Procedures for establishing the coordination are previously given for silicon-carbide arresters.

Typical characteristics collected include the front of wave value at 0.5 µs, the maximum switching surge protective level, and maximum discharge voltages at 5 kA, 10 kA, and 20 kA. Since the metal oxide arresters have no sparkover, the front-of-wave value is used in place of the sparkover value.

Acceptable protective margins are considered to be similar to the silicon-carbide protective levels. Generally accepted practice is to provide a 20 percent margin between the transformer front of wave (TFOW) strength and the arrester front of wave rating based on the arrester front of wave rating (AFOW), a 20 percent margin between the BIL withstand rating (BIL) and the arrester lightning protective level (LPL), and a 15 percent margin between the transformer switching surge withstand (BSL) and the arrester surge protective level (SPL). The switching surge withstand strength of the transformer insulation is usually specified at 83 percent of impulse BIL. These ratings are summarized as follows:

Ratio F = TFOW / AFOW ≥ 1.20
Ratio L = BIL / LPL ≥ 1.20
Ratio S = BSL / SPL ≥ 1.15

5.8.7.7   Direct Stroke Shielding: This topic is covered under the application for silicon-carbide arresters.

**5.8.7.8   Multiple Lines:** This topic is covered under the application for silicon-carbide arresters.

5.8.7.9   Standards and Guides: There are two principal national standards or guides pertaining to metal oxide valve surge arresters: IEEE C62.11 and IEEE 62.22.

5.8.7.9.1   IEEE C62.11, "IEEE Standard for Metal-Oxide Surge Arresters for Alternating Current Power Circuits." This standard contains basic information on arresters such as definitions, service conditions, classification and voltage ratings, performance characteristics and tests, test procedures, design tests, conformance tests, and construction. Some pertinent sections are as follows:

   a.   Section 4, Service Conditions.
   b.   Standard arresters are designed for ambient temperatures not exceeding 40°C (104°F) and altitudes not exceeding 1800 meters (6000 feet).
   c.   Section 5, Table I (Table 5-57), Voltage in Kilovolts, lists the standard voltage duty ratings and the corresponding MCOV available for metal oxide arresters.
   d.   Section 8, Design Tests, indicates the tests that devices have to adhere to so as to comply with the standard. The differences in the different arrester classifications of distribution, intermediate, and station class are listed in the various subsections as applicable. The table in Appendix B of IEEE Std. C62.11, Surge Arrester Classification Prescribed Test Requirements, summarizes the test values required for the various tests.
   e.   Section 8.1.1, Table 2a, Insulation Withstand Test Voltages, lists the various insulation requirements of all ratings of the different arrester classifications.
   f.   Section 8.3.1, Table 3, Lightning Impulse Classifying Current, lists the impulse value crest amperes for the various ratings of station, intermediate, and distribution arresters.
   g.   Section 8.3.2, discharge voltage–time characteristics, lists the surge value crest amperes for the various ratings of station, intermediate, and distribution arresters.

5.8.7.9.2   IEEE Std. C62.22, "Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems." This standard is an excellent guide to the basic application of metal oxide arresters in electric substations. It contains information on general procedures, systematic procedures for protection of transformers and substation equipment, and protection of other equipment such as dry-type insulation, shunt capacitor banks, underground cables, gas-insulated substations, and rotating machines. Of particular interest is the Typical Voltage–Time Curve for Coordination of Arrester Protective Levels with Insulation Withstand Strength for Liquid-Filled Transformers (see Figure 5-40). This curve illustrates the protection to transformer insulation provided by an arrester.

Appendix A to IEEE Std. C62.22, Lightning Flashes, Lightning Stroke Currents, Traveling Waves, and Station Shielding, provides a discussion of the characteristics of lightning strokes, densities, current values, and characteristics. The use of shielding in substations is discussed with respect to prevention of direct strokes from hitting substation equipment.

CHOPPED WAVE WITHSTAND (CWW)

$$PR_{L1} = \frac{CWW}{FOW}$$

BASIC LIGHTNING IMPULSE INSULATION LEVEL (BIL)

$$PR_{L1} = \frac{BIL}{LPL}$$

BASIC SWITCHING IMPULSE INSULATION LEVEL (BSL)

20 KA

FRONT OF
WAVE
PROTECTIVE
LEVEL
(FOW)

10 KA

$$PR_S = \frac{BSL}{SPL}$$

5 KA

DISCHARGE
VOLTAGE
AT
LIGHTNING
IMPULSE
CLASSIFYING
CURRENT
(LPL)

SWITCHING IMPULSE PROTECTIVE LEVEL (SPL)

CREST VOLTAGE (kV)

.1   1   10   100   1000   60Hz   10000

TIME (μs)
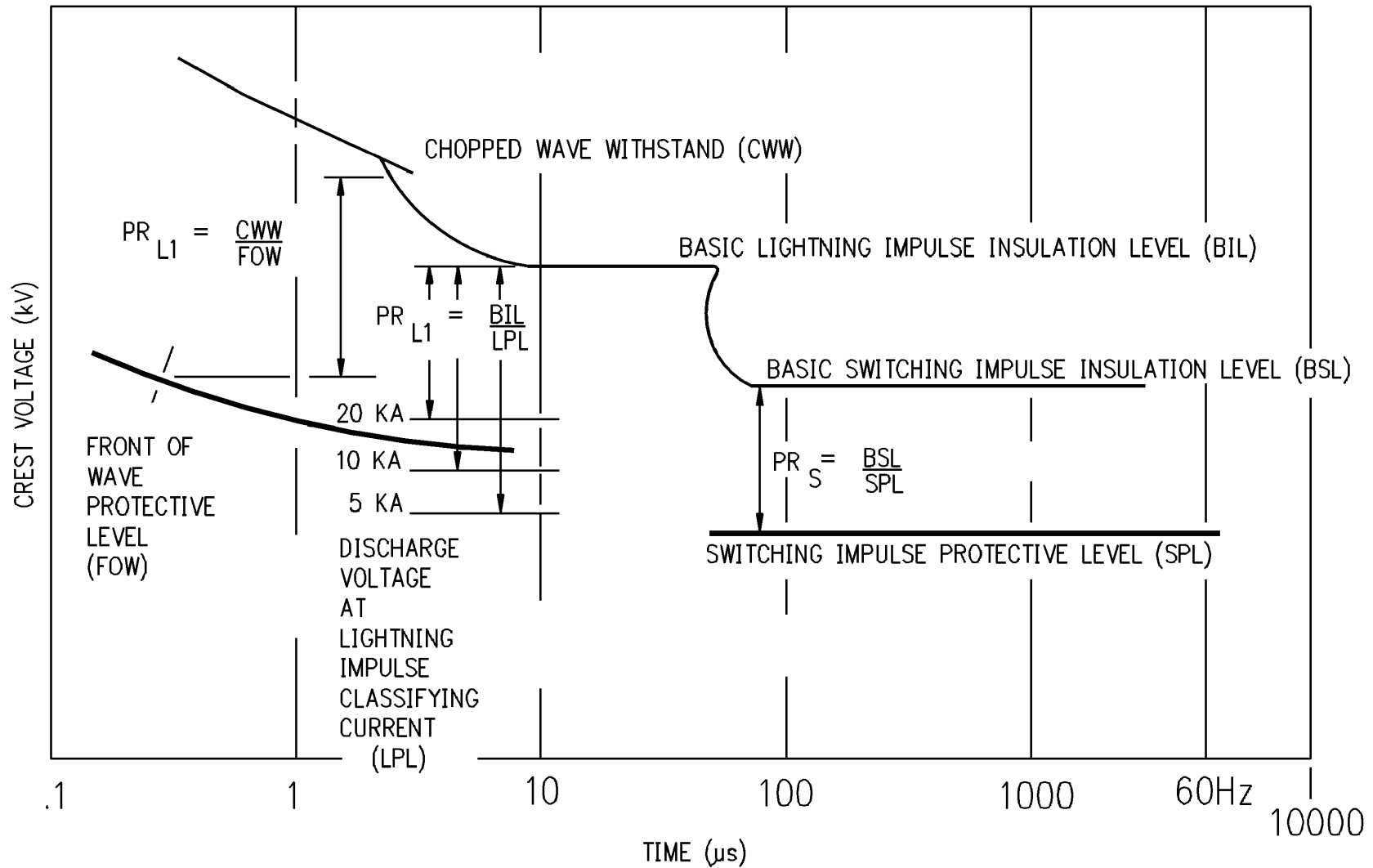
Figure 5-40: Typical Volt–Time Curve for Coordination of Arrester Protective Levels with Insulation Withstand Strength for Liquid-Filled Transformers. Ref. IEEE Std. C62.22-1991, Figure 8. Copyright © 1991. IEEE. All rights reserved.

Appendix B to IEEE Std. C62.22, COG for Various Conditions, contains additional information regarding coefficients of grounding.

Appendix C, Calculations of Surge Arrester Separation Distances, provides additional discussion and calculation procedures for determining the degree of protection when the surge arrester is separated from the equipment that is being protected.

5.8.7.10 **Guide for the Application of Metal Oxide Surge Arresters for Alternating-Current Systems** (see IEEE Std. 62.22 for details). An example of surge arrester selection will be worked out along with each guide step to illustrate the procedure. The example is arrester selection for a 230 kV substation coordinated with the transformer BIL. The 230 kV substation is supplied by one 230 kV line. Both the substation and the line are effectively shielded. This is the same example used with the silicon-carbide arresters.

5.8.7.10.1 <u>Conditions for Application</u>: The conditions are as indicated in Section 5.8.6.8 and as follows:

$E_{LL\,(MAX)} = 242$ kV $\quad$ $E_{LG(MAX)} = 140$ kV
Coefficient of grounding (COG): $\quad$ R1 = R2 = 0.1 * X1, R0/X1 = 0.8, X0/X1 = 2.5
COG = 75
$E_{LG(MAX\,TOV)} = 181$ kV for less than 1 sec during fault conditions (242 * 0.75 = 181)
Possible transformer BILs to investigate (kV): $\quad$ 900, 825, 750, 650
Impulse currents to consider (kA): 5, 10, 20
Switching surge: Not applicable for transformer

5.8.7.10.2 <u>Arrester Selection</u>: Minimum MCOV rating for the application is 140 kV equal to the $E_{LG(MAX)}$. Table 5-57 indicates this rating is a standard rating and, as such, is chosen as the initial MCOV rating for the arrester.

The temporary overvoltage is a maximum line-to-ground voltage of 181 kV for less than 1 second. The TOV is evaluated to determine if adjustments are to be made to the arrester selection. The per unit applied voltage based on the MCOV rating is 181/140 = 1.29. Figure 5-39 indicates that 1.29 per unit voltage may be applied to the arrester for more than 100 seconds. The magnitude and duration of the TOV do not warrant increasing the MCOV rating of the arrester.

Figure 5-41 indicates the insulation coordination for the 230 kV transformer protected with a typical metal oxide arrester. The protection curves for the selected transformer BILs are plotted along with the applicable points for the 140 kV MCOV arrester. The discharge current voltage levels and the switching surge voltage levels are indicated. The protective margins for the BILs and the surge levels are indicated. The protective ratios realized by the protective levels of the arrester substantially exceed the recommended ratios of 20 percent for the front-of-wave and lightning impulse levels, and 15 percent for the switching surge level.

Figure 5-42 shows curves for a 152 kV MCOV surge arrester with a corresponding duty-cycle rating of 192 kV, the same as the example used for the silicon-carbide arrester. The protective ratios realized by the protective levels of the arrester substantially exceed the recommended ratios of 20 percent for the front-of-wave and lightning impulse levels, and 15 percent for the switching surge level.
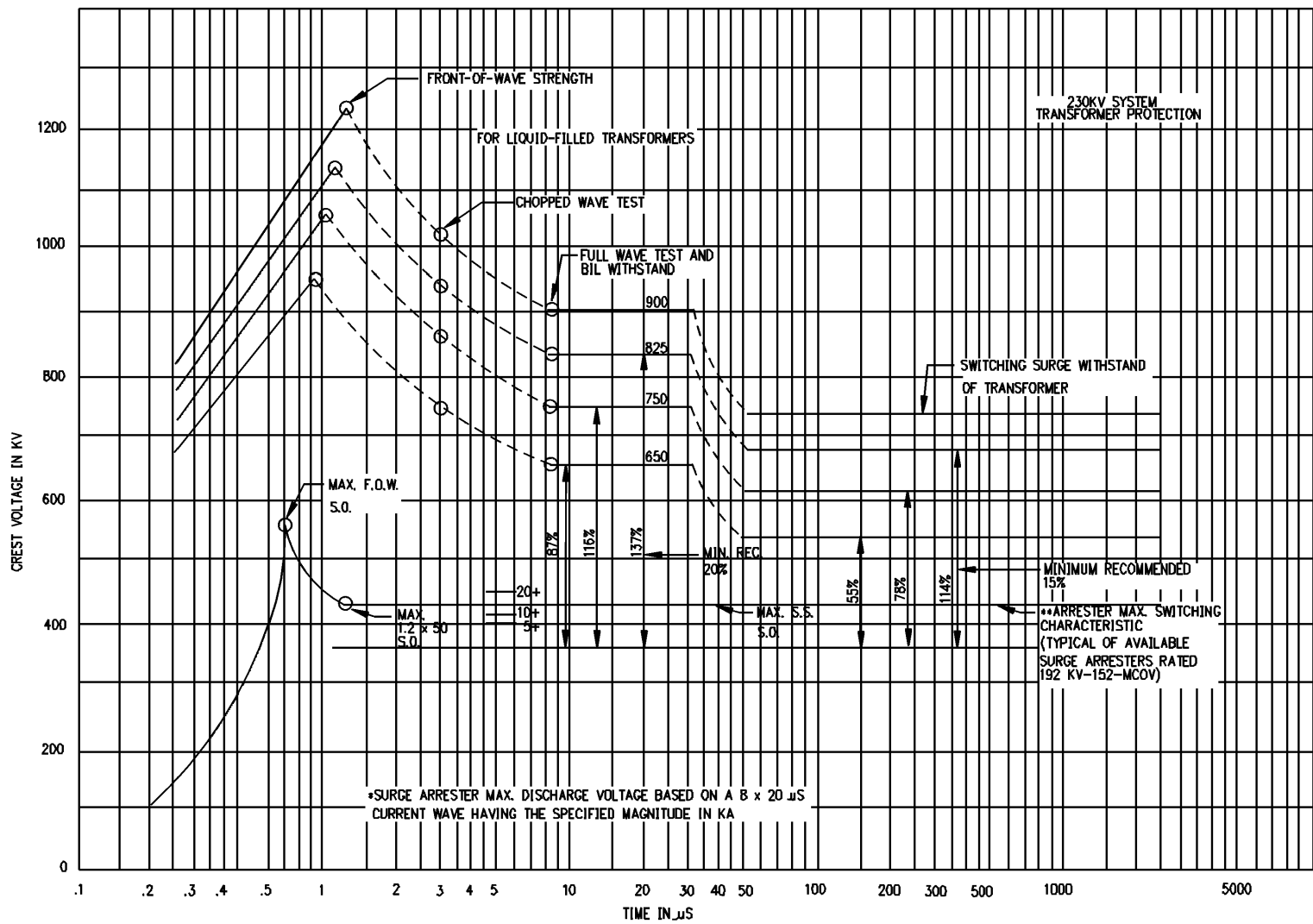
Note: ** MCOV Peak Value: $152 \times \sqrt{2} = 215$ kV

Figure 5-41: Typical Volt–Time Curves for Coordination of 152 kV MCOV Metal Oxide Surge Arrester Protective Levels with Insulation Withstand Strength

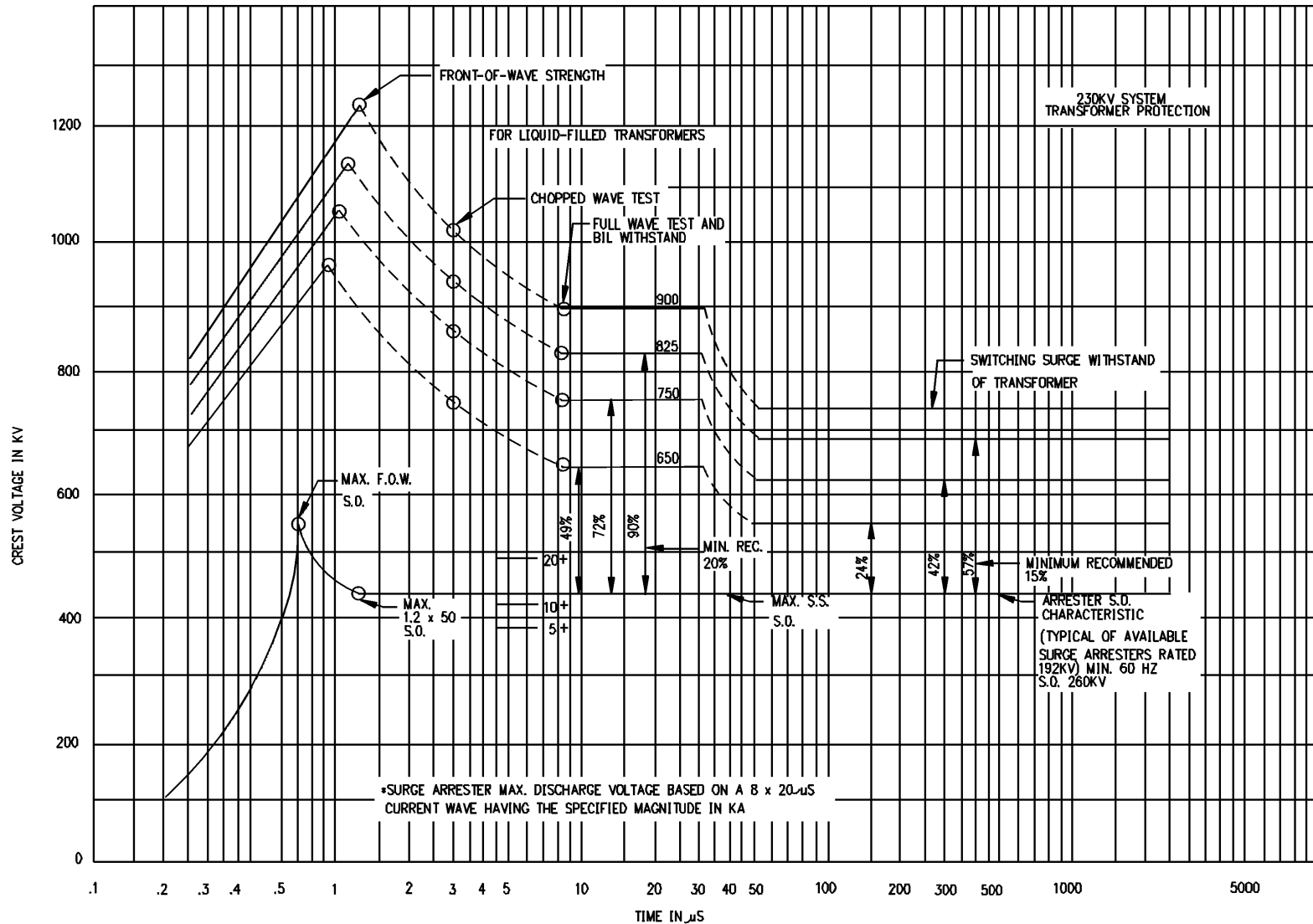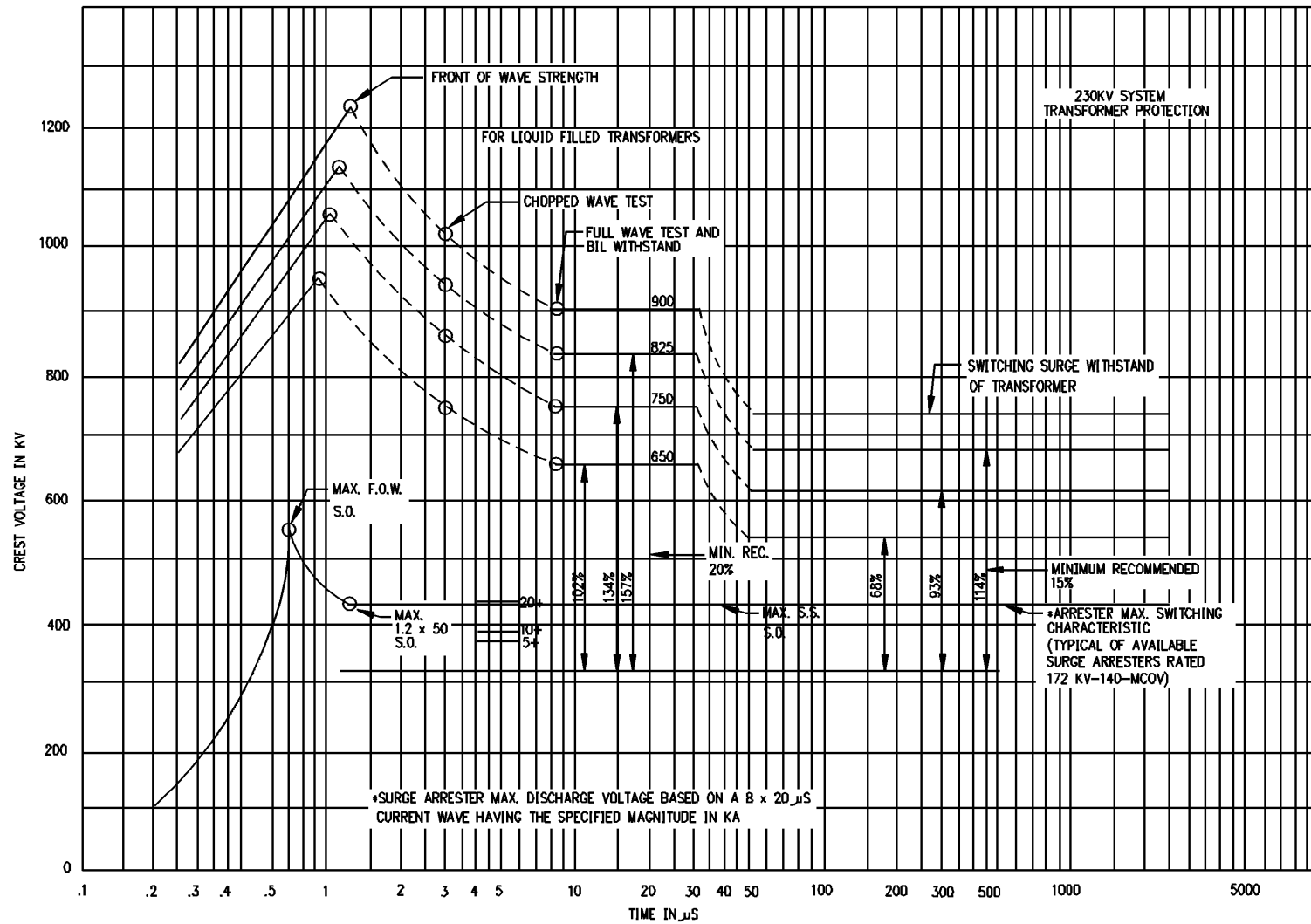Note: ** MCOV Peak Value: * 140 x $\sqrt{2}$ = 198 kV

Figure 5-42: Typical Volt-Time Curves for Coordination of 140 kV MCOV Metal Oxide Surge Arrester
Protective Levels with Insulation Withstand Strength

Substantial improvement in protective margins is realized with the use of metal oxide arresters. Protection provided by two ratings of arresters is shown: 192 kV, which corresponds to the arrester rating in Figure 5-35, and a 172 kV arrester, which corresponds to an MCOV rating of 140 kV, the minimum recommended rating for the 230 kV voltage class.

5.8.8 Location

5.8.8.1   General: In general, surge arresters should be located at or near the main transformers on both the high- and low-voltage sides. It may be desirable to also locate arresters at the line entrances or, in some cases, on a bus that may be connected to several lines. They should be located to give maximum possible protection to all major substation equipment.

In many cases, the arresters protecting the main transformer may be mounted directly on the transformer.

Lightning strokes can produce surges with steep wave fronts, voltage gradients, reflections, or oscillations and high rates of rise of current, which can result in large differences in the line-to-ground voltage between even closely spaced points. It is extremely important to locate the arresters as close as practical to the apparatus requiring protection. The arrester lead length should be kept as short as practical. If possible, the arrester should be connected directly to the jumper connecting the equipment to the system. Following is a general guide for determining maximum separation distances between arrester lead tap and transformer, considering the effect of arrester lead length.

5.8.8.2 Arrester Separation Distance and Lead Length

5.8.8.2.1   Impressed Voltage: The voltage impressed on the substation transformer after arrester operation may be much higher than the arrester discharge voltage if either arrester separation distance (S) or lead length (L) is excessive. Consequently, these factors have to always be considered in applying arresters. Application curves have been developed to facilitate this.

5.8.8.2.2   Separation Distance: Arrester separation distance (S) is defined as the distance from the line arrester lead junction to the transformer bushing. Voltage reflections result when the discharge voltage traveling as a wave arrives at the transformer. If the arrester is very close to the transformer, these reflections are cancelled almost instantaneously by opposite polarity reflections from the arrester. As the separation distance increases, the cancellation becomes less and less effective, and the voltage at the transformer may increase to almost twice the arrester discharge voltage.

5.8.8.2.3   Lead Length: Arrester lead length (L) is defined as the total length of the conductor from the junction of the surge arrester lead with the line or transformer circuit to physical ground, but not including the length of the arrester itself. When the arrester discharges, surge current flows to ground over the lead length. The resulting voltage drop, L di/dt, is proportional to the lead length and adds to the arrester discharge voltage.

5.8.8.2.4   Surge Voltage Increase: The increase in surge voltage due to separation distance and lead length may be evaluated by the method given in AIEE Transactions Paper 63-229. It will be satisfactory, however, to use the application curves from this reference, which are reproduced as Figures 5-43, 5-44, and 5-45, to determine maximum lead lengths and separation distances for high-side arresters, provided that modern arresters are used. For this purpose, any arrester manufactured in the United States during or after 1960 may be considered modern.

NO.	NOMINAL SYSTEM VOLTAGE-kV	CRITICAL LINE FLASHOVER-kV	TRANS- FORMER BIL - kV	ARRESTERS RATING	TYPE
1	23	500	150	25	INT
2	34.5	600	200	30	INT
3	34.5	600	200	37	STA
4	34.5	600	200	37	INT
5	46	750	250	40	INT
6	46	750	250	50	STA
7	46	750	250	50	INT
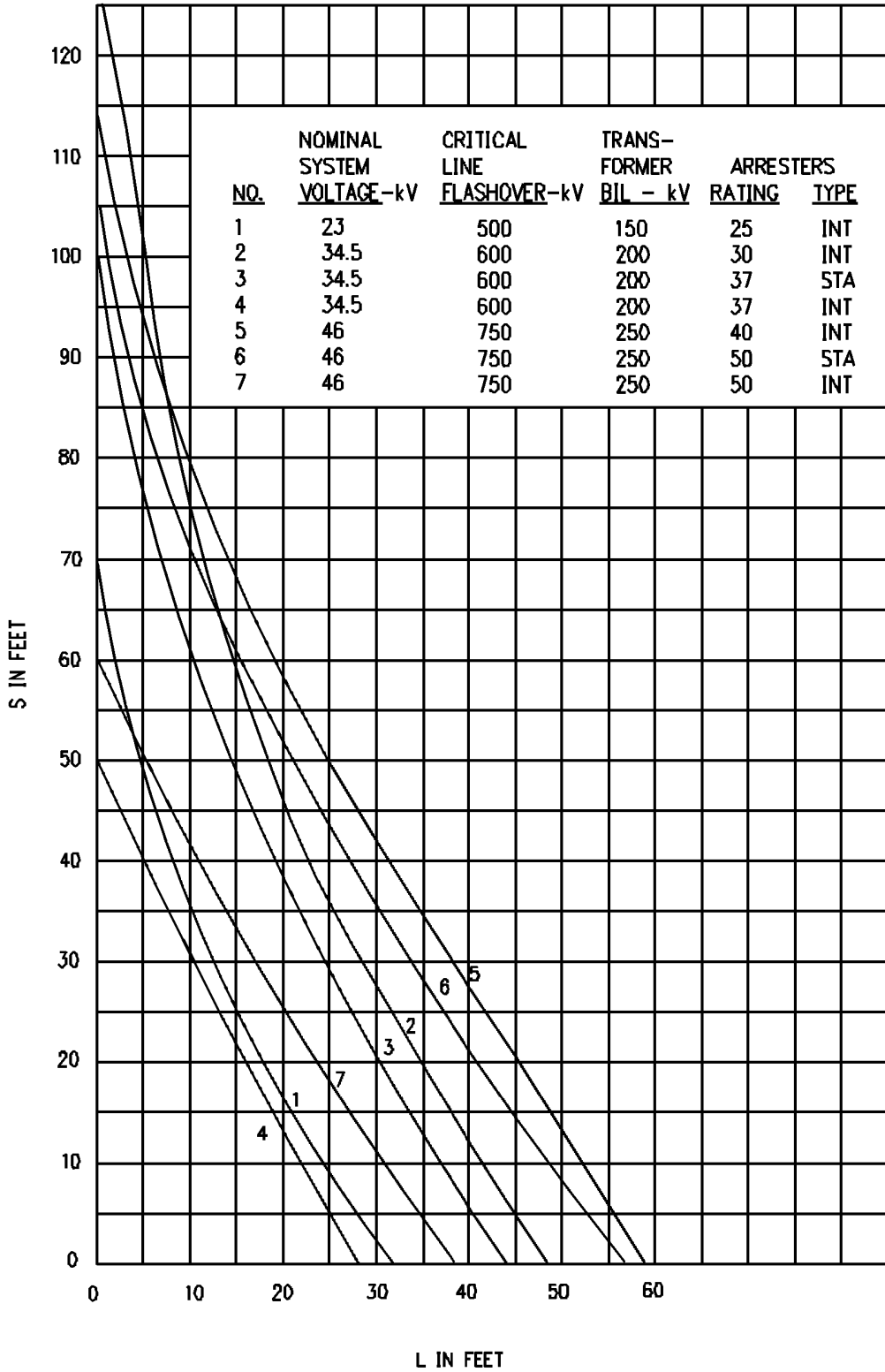
Figure 5-43: Maximum Safe Separation Distance of Lightning Arresters from Protected Equipment—
Nominal System Voltage 23 kV Through 46 kV (L = Arrester Lead Length, S = Separation).
Ref. IEEE Std. C62.22-1991. Copyright © 1991. IEEE. All rights reserved.

NO.	NOMINAL SYSTEM VOLTAGE-kV	CRITICAL LINE FLASHOVER-kV	TRANS- FORMER BIL - kV	ARRESTERS RATING	TYPE
8	69	1020	350	60	STA
9	69	1020	350	60	INT
10	69	1020	350	73	STA
11	69	1020	350	73	INT
12	69	600	350	73	INT
13	115	1220	450	97	STA
14	115	760	550	121	STA
15	138	1380	550	109	STA
16	138	930	650	145	STA
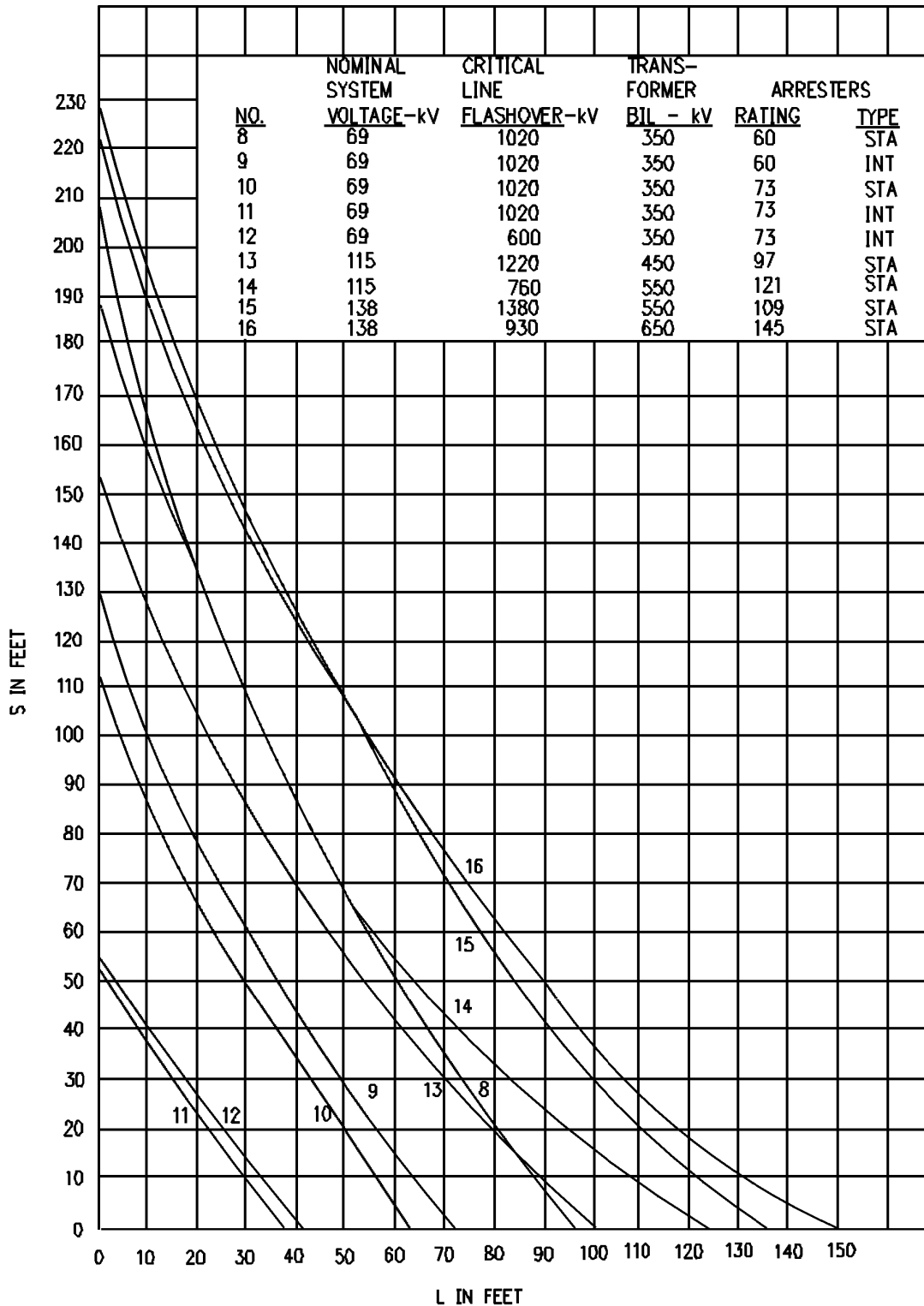
Figure 5-44: Maximum Safe Separation Distance of Lightning Arresters from Protected Equipment—
Nominal System Voltage 69 kV Through 138 kV (L = Arrester Lead Length, S = Separation).
Ref. IEEE Std. C62.22-1991. Copyright © 1991. IEEE. All rights reserved.

NO.	NOMINAL SYSTEM VOLTAGE-kV	CRITICAL LINE FLASHOVER-kV	TRANS- FORMER BIL - kV	ARRESTERS RATING	TYPE
17	161	1020	650	145	STA
18	161	1020	750	169	STA
19	230	1440	900	195	STA
20	230	1750	1050	242	STA
21	230	1440	1050	242	STA
22	345	1600	1050	258	STA
23	345	1600	1050	264	STA
24	345	1600	1175	258	STA
25	345	1600	1175	264	STA
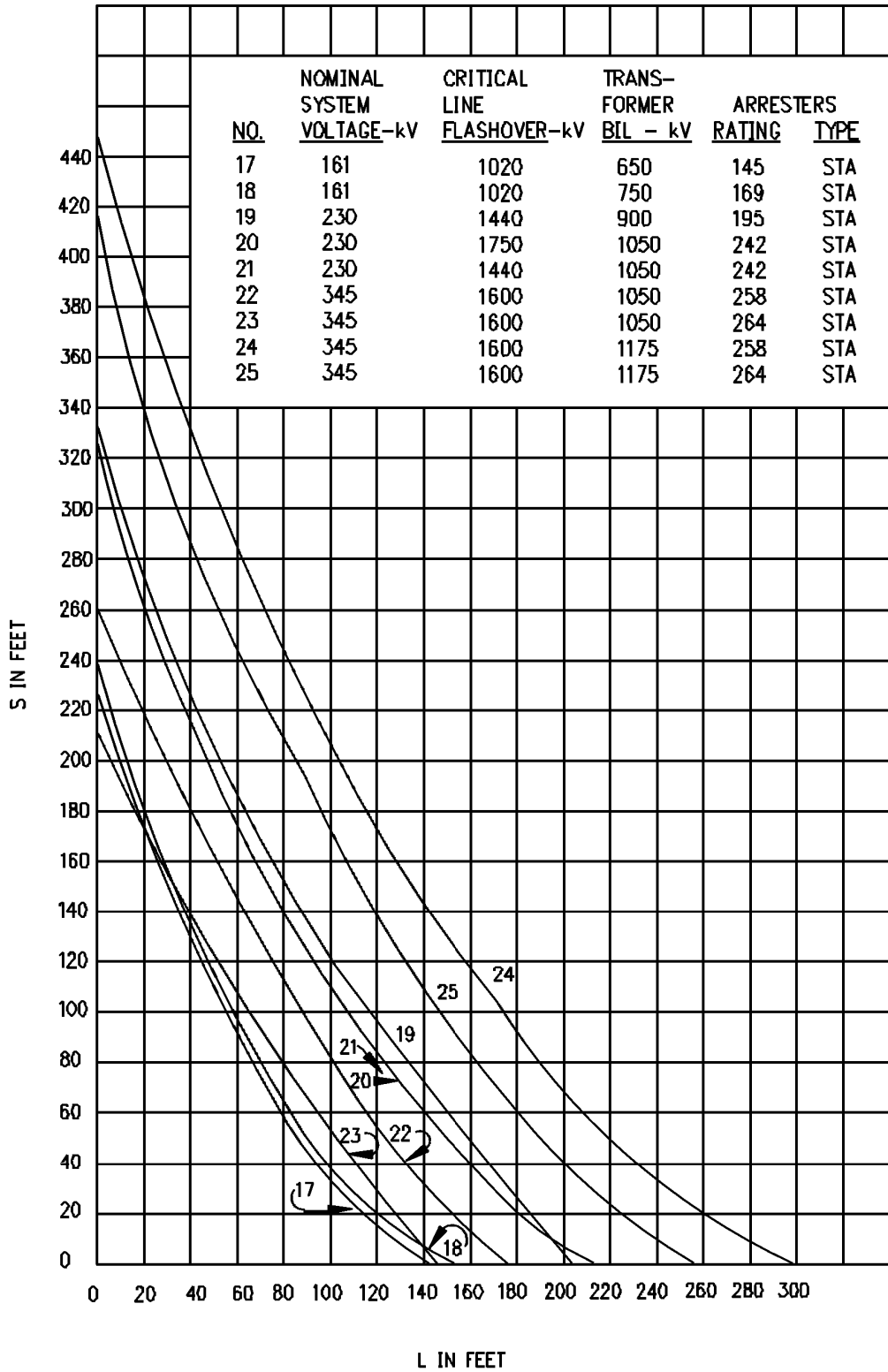
Figure 5-45: Maximum Safe Separation Distance of Lightning Arresters from Protected Equipment— Nominal System Voltage 161 kV Through 345 kV(L = Arrester Lead Length, S = Separation).
Ref. IEEE Std. C62.22-1991. Copyright © 1991. IEEE. All rights reserved.

5.8.8.3   Special Situations

5.8.8.3.1   On smaller substations with high-side fuses, the arrester should be located on the line side of the fuse so as to prevent the lightning discharge from passing through the fuse.

5.8.8.3.2   Arresters need not be installed on the line side of high-voltage air-break switches. However, they should be connected close enough to protect the switch adequately when the switch is closed. Line entrance gaps may be used on the line side for protection when the switch is open. See Section 5.8.9, Protection at Line Entrances.

5.8.8.3.3   Arresters of the valve type may be installed on the low-voltage distribution bus. They should be installed on the load side of the feeder overcurrent device (recloser, fuse, or circuit breaker) and any related disconnecting switch.

5.8.8.3.4   Continuous metallic sheath cables from substation to overhead lines should be protected by arresters at the junction, and should be grounded effectively at the base of the cable terminal structure and directly to the cable sheath. If the overhead line is unshielded, additional protective devices may be required a few spans before the junction.

The cable sheath should be bonded to the substation ground at the substation end. It may also be necessary to install arresters at the substation equipment end if the cable is such that two times the protection level of the junction arrester exceeds 80 percent of the substation BIL. This is due to reflection at the equipment end.

5.8.8.3.5   On high-voltage wye-connected transformers with ungrounded neutral, voltage reflections at the neutral can approach two times the voltage applied simultaneously at the line terminals. It is therefore necessary to employ a surge arrester from neutral to ground to limit these surge voltages, especially if the transformer has graded insulation. The rating of the arrester should be approximately 1.2 times the normal line-to-neutral system voltage.

5.8.9 <u>Protection at Line Entrances</u>

Lightning wave fronts may approach 1000 kV/µs, resulting in a gradient of 3.3 kV/m difference in line-to-ground potential. Most, however, do not exceed 500 kV/µs, and this value is considered a basis for good practice. At open circuit points, these waves are reflected back at nearly double the original rate of rise, increasing the possibility of a flashover or equipment damage close to that point. It is apparent that protection should be considered for the line entrances on large substations, especially where line breakers and disconnect switches may be open, constituting dead-end reflections. Surge arresters will provide the most effective means of protection, but line entrance gaps may be sufficient. Line entrance protective gaps may be considered as an economical alternative to surge arresters at substation entrances of all overhead lines 23 kV and above to provide additional protection for substation insulation under the following conditions:

1. When steep front incoming surges would break down insulation near the line entrance or on the bus (station arresters may be far too distant to provide adequate protection);
2. When part of the station insulation is isolated from protective influence of the station arresters by switching; and
3. When the station arrester has been damaged or otherwise removed from service so that its protection is not available

Note that the operation of a gap places a fault on the system that has to be cleared by a circuit breaker, recloser, or fuse, remote from the line end in question. The engineer, along with operations personnel, should evaluate the suitability of this type of operation.

5.8.10 References

AIEE Transactions Paper 63-229, "Simplified Method for Determining Permissible Separation Between Arresters and Transformers."

ANSI Std. C84.1, "Voltage Ratings for Electric Power Systems and Equipment (60Hz)."

ANSI/IEEE Std. C62.2, "Guide for Application of Gapped Silicon-Carbide Surge Arresters for Alternating-Current Systems."

ANSI/IEEE Std. C62.92, "IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems Part I – Introduction."

IEEE Std. C62.1, "Standard for Gapped Silicon-Carbide Surge Arresters for Alternating-Current Power Circuits."

IEEE Std. C62.11, "Standard for Metal-Oxide Surge Arresters for Alternating-Current Power Circuits."

IEEE Std. C62.22, "Guide for the Application of Metal Oxide Surge Arresters for Alternating-Current Systems."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

Westinghouse Electric Corp., *Transmission and Distribution Reference Book*, Pittsburgh: Westinghouse Electric Corp., 1950.

5.9 AUTOMATIC CIRCUIT RECLOSERS

5.9.1 General

This section covers single- and three-phase alternating-current automatic circuit reclosers.

An automatic circuit recloser is a self-controlled protective device used to interrupt and reclose automatically an alternating-current circuit through a predetermined sequence of opening and reclosing followed by resetting, lockout, or hold closed. Figures 5-46 and 5-47 show single- and three-phase reclosure, respectively.

5.9.1.1 Purpose: Reclosers are installed to provide maximum continuity of service to distribution loads, simply and economically, by removing a permanently faulted circuit from the system or by instant clearing and reclosing on a circuit subjected to a temporary fault caused by lightning, trees, wildlife, or similar causes. Unlike fuse links, which interrupt either temporary or permanent faults indiscriminately, reclosers are able to distinguish between the two types of faults, permanent and temporary. They give temporary faults repeated chances to clear or to be cleared by a subordinate protective device. If the fault is not cleared, the recloser recognizes the fault as permanent and operates to lock out or, in some applications, hold closed (see Section 5.9.5.4).

UNIVERSAL CLAMP TYPE
TERMINALS
Accept copper or aluminum
conductors horizontally or
vertically.

COVER-CLAMPED
BUSHINGS
Wet-process porcelain; can
be field replaced.

NAMEPLATES
Show complete recloser
data.

O-RING GASKET
Forms positive moisture-
proof seal between head
casting and tank.

HYDRAULIC PUMP AND
LOCKOUT PISTON
Counts operations; resets
operating program.

INSULATING SUPPORTS
Epoxy-fiberglass; provide
mechanical and dielectric
strength to support
hydraulic and interrupting
mechanisms.

INTERRUPTER ASSEMBLY
Provides fast arc extinction.

MOVING CONTACTS
Provide double-break
interruption; have long-life,
copper-tungsten alloy tips.

LIFTING STRAP
Facilitates hoisting
during installation and
maintenance.

OPERATIONS COUNTER
Records all recloser trip
operations; large, easy-to-
read figures.

SLEET HOOD
Houses manual operating
handle, non-reclosing lever,
and operations counter.

NON-RECLOSING
HANDLE
Under sleet hood;
switchstick operable; when
pulled down, sets recloser to
lockout after one operation.

MANUAL OPERATING
HANDLE
Provides indication of
locked-out recloser; permits
manual opening and closing.

BYPASS GAP
Protects series-trip coil from
lightning surges.

SERIES TRIP-SOLENOID
Trips recloser when current
greater than minimum-trip
value flows.

ARC SHIELD
Protects operating coil from
contact arcing and resultant
gases.

Figure 5-46: Typical Single-Phase Hydraulically Controlled Oil Circuit Breaker.
Courtesy of Cooper Power Systems.

OIL DIP STICK
Aids in checking oil level.

RECEPTACLE
Provides connection
for control cable.

MANUAL OPERATING HANDLE
Provides manual opening
and lockout.

CONTACT POSITION
INDICATOR

NAMEPLATES
Supply complete recloser data.

INTERRUPTERS
Self-generating; vented for fast
arc-extinction.

LIFTING STRAPS
Used for hoisting recloser or lift-
ing mechanism out of tank.

CLAMP-TYPE TERMINALS
Accept NO. 1/0—500 MCM
cable in horizontal or vertical
position.

BUSHINGS
Wet-process porcelain, glaze
color is light gray, Munsell 5BG
7.0/0.4

O-RING GASKET
Of Buna-N is confined, and pro-
vides positive weatherproof seal
between head casting and tank
under all operating conditions.

CLOSING SOLENOID
Closes contacts and charges
opening springs.

MOVING CONTACTS
Have copper-tungsten alloy tips
for long life.

Figure 5-47: Recloser with Single-Phase Tripping and Three-Phase Lockout.
Courtesy of Cooper Power Systems.

5.9.1.2   Application: Automatic circuit reclosers are used in distribution substations and on branch feeders to protect distribution circuits and to switch them. (see Figure 5-48). Their proper application requires a study of the load and short-circuit characteristics of both the protecting and the protected equipment. This includes high-voltage fuses or other protection in the supply to a substation transformer bank, a circuit breaker or reclosers at the distribution voltage supplying the feeder at the substation, various line reclosers, sectionalizers, line fuses, the wire arc burn-down characteristic at the fault location, ground resistance, etc. In selecting reclosers, it is recommended that the procedure outlined in ANSI Std. C37.61, Paragraph 4.3, be followed.
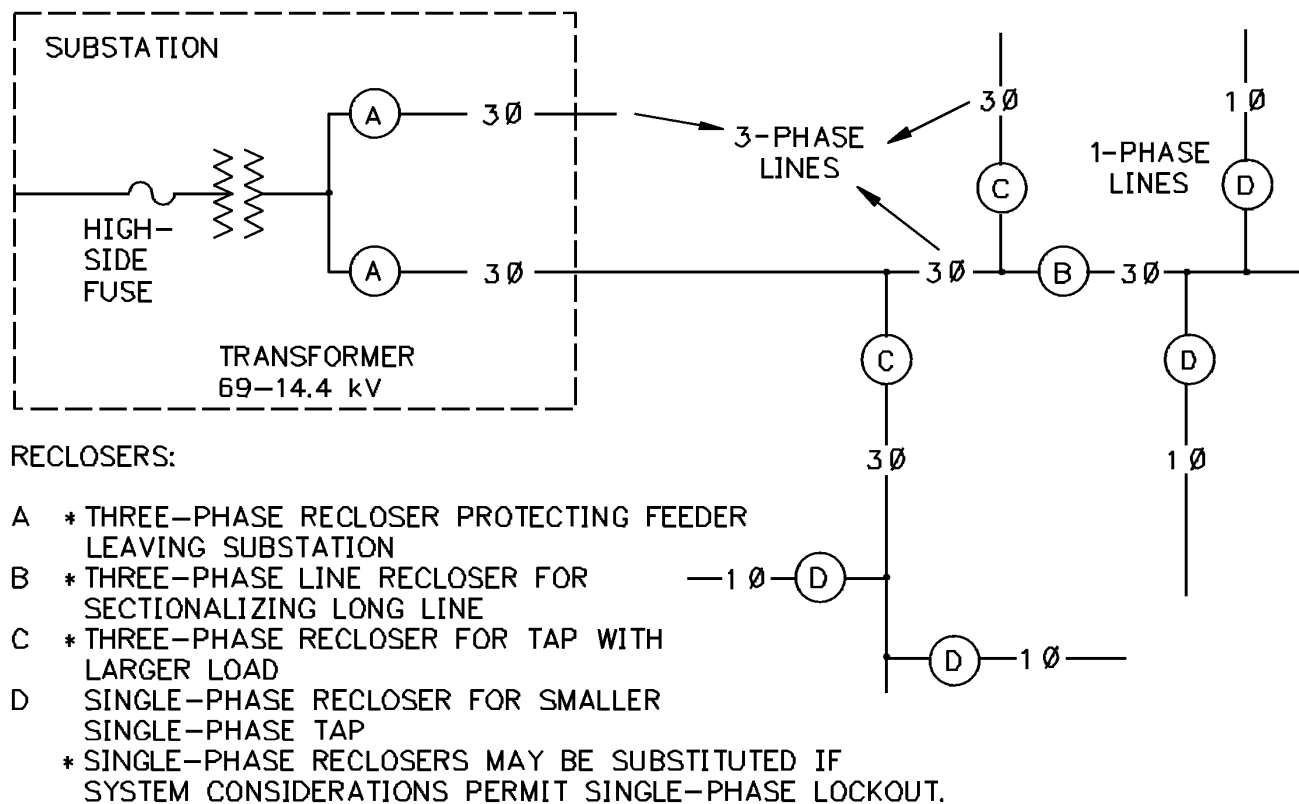
Figure 5-48: Typical Line Diagram of Distribution Circuit Showing Application of Reclosers

5.9.1.3 Service Conditions: Reclosers are suitable for operation at their standard rating within an ambient temperature range of –30ºC to +40ºC (–22ºF to 104ºF) and at altitudes not exceeding 1000 meters (3300 feet). They may be applied at higher or lower temperatures, hydraulic slowed at 32ºF, but performance may be affected and the manufacturer should be consulted regarding special considerations for such applications. They also may be applied at altitudes higher than 1000 meters (3300 feet), provided that corrections (reductions) are made in impulse insulation level, rated maximum voltage, and rated continuous current. Correction factors (multipliers) are given in Table 5-59, Columns 3 and 4. Reclosers designed for standard temperature rise may be used above an altitude of 1000 meters

(3300 feet) at normal current rating without exceeding ultimate standard temperature limits, provided that the ambient temperature does not exceed the maximum +40ºC limit reduced by the correction factor given in Table 5-59, Column 5.

Table 5-59: Altitude Correction for Automatic Circuit Reclosers.
Ref. ANSI/IEEE Std. C37.60–1981, Table 1.
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Altitude		Correction Factor (Multiplier)		
(1)	(2)	(3)	(4)	(5)
Feet	Meters	Voltage Rating	Current Rating	Ambient Temp.
3300	1000	1.00	1.00	1.00
4000	1200	0.98	099	0.99
5000	1500	0.95	0.99	0.98
10000	3000	0.80	0.96	0.92
16000	4900	0.63	0.93	0.85

The rated interrupting current, current-related required capabilities, and rated interrupting time are not affected by altitude.

5.9.1.4   Standards: Applicable ANSI Standards (listed below) are comprehensive and valuable references when automatic circuit reclosers (ACRs) are being considered. Consult RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers," for manufacturers' types of ACRs.

- ANSI/IEEE C37.60, "Requirements for Automatic Circuit Reclosers for Alternating-Current Systems"

- ANSI C37.61, "Guide for the Application, Operation and Maintenance of Automatic Circuit Reclosers"

5.9.2 Recloser Classifying Features

5.9.2.1   Single-Phase or Three-Phase: Both single- and three-phase reclosers are available to satisfy application requirements.

5.9.2.1.1   Single-Phase Reclosers: Single-phase reclosers are used to protect single-phase lines, such as branches or taps of a three-phase feeder. They can also be used on three-phase circuits where the load is predominantly single phase. Thus, when a permanent phase-to-ground fault occurs, one phase can be locked out while service is maintained to the remaining two-thirds of the system.

5.9.2.1.2   Three-Phase Reclosers: Three-phase reclosers are used where lockout of all three phases is required for any permanent fault. They are also used to prevent single phasing of three-phase loads, such as large three-phase motors. Three-phase reclosers have two modes of operation.

5.9.2.1.2.1   The first, single-phase trip and three-phase lockout, consists of three single-phase reclosers mounted in a single tank, with mechanical interconnection for lockout only. Each phase operates

independently for overcurrent tripping and reclosing. If any phase operates to lockout condition due to a permanent fault, the mechanical linkage trips open the other two phases and locks them open. Thus, extended single-phase energization of three-phase loads is prevented. This type of operation is provided for smaller recloser types.

5.9.2.1.2.2   Larger reclosers make use of the second mode of operation: three-phase trip with three-phase lockout. For any fault—single-phase-to-ground, phase-to-phase, or three-phase—all contacts operate simultaneously for each trip operation. The three phases, mechanically linked together for tripping and reclosing, are operated by a common mechanism.

5.9.2.2   **Control Intelligence:** The intelligence that enables a recloser to sense overcurrents, select timing operation, time the tripping and reclosing functions, and finally lock out, is provided by its control. There are two basic types of control schemes used: integral "hydraulic" control or "electronic" control located in a separate cabinet. A recloser employs one of these controls.

5.9.2.2.1   Hydraulic Recloser Control: Hydraulic recloser control is used in single-phase reclosers and in smaller ratings of three-phase reclosers. It is built as an integral part of the recloser. With this type of control, an overcurrent is sensed by a trip-coil connected in series with the line. When the overcurrent flows through the coil, a plunger is drawn into the coil to trip open the recloser contacts. Timing and sequencing are accomplished by pumping oil through separate hydraulic chambers or ducts.

5.9.2.2.2   Electronic Recloser Control: Electronic recloser control is used with some single-phase reclosers and larger three-phase reclosers. Compared to the hydraulic control, it is more flexible, more easily adjusted, and more accurate. The electronic control, housed in a cabinet separate from the recloser, conveniently permits changing timing, trip current levels, and sequences of recloser operations without de-energizing or untanking the recloser. A wide range of accessories are available from metering capabilities on some models to modifying the basic operation, solving many different application problems.

Line current is sensed by special sensing current transformers in the recloser. The recloser and control are connected by a multiconductor control cable that carries sensing transformer secondary currents to the control and the necessary trip and reclose signals from the control to the recloser. A dc battery either supplies the control or provides backup, ensuring adequate operating power under all fault conditions. Most reclosers require an external ac source either to charge the dc battery or provide control power.

5.9.2.3   **Tripping:** Series coil and non-series coil tripping are characteristics of individual classifications of reclosers.

5.9.2.3.1   Series Coil Tripping: Series coil tripping is used on hydraulically controlled single-phase reclosers and three-phase reclosers. Sensing of fault current is provided by a series-connected solenoid coil (magnetic actuator) that carries its rated line current. When a fault occurs, tripping is initiated by the solenoid plunger. The plunger, normally held at rest by the closing springs, is pulled into the coil and causes overtoggling of trip springs in the operating mechanism that opens the recloser contacts.

Tripping simultaneously charges closing springs that then close or reclose the recloser when the proper closing signal is present, thus making the recloser ready for another tripping operation.

5.9.2.3.2   Non-Series Coil Tripping: Non-series coil tripping is used on some single-phase vacuum reclosers and some three-phase reclosers. It may consist of a tripping solenoid, energized from an

external power supply, that over-toggles tripping springs in the same way as performed by the series trip solenoid. It may also consist of a tripping spring simply released by a small tripping solenoid also externally energized. In both cases, the tripping spring is previously charged by a closing solenoid or closing motor during a closing or reclosing operation of the recloser. Other technologies do not utilize spring charging, relying on the solenoid to perform the tripping operation.

5.9.2.4 Closing: Various methods of closing and reclosing are available, depending on the recloser selected.

5.9.2.4.1 Spring Closing: Spring closing is utilized on most single-phase and some three-phase reclosers. In each case, the closing spring is charged during a previous tripping operation.

5.9.2.4.2 Solenoid Closing: Solenoid closing is utilized on some single-phase and some three-phase reclosers. The solenoid coil may be high-voltage ac and connected line to grounded neutral or it may be low-voltage dc energized from a battery. A low-voltage rectifier accessory is also available to permit use of local ac power supply for closing. Some methods utilize solenoid closing to charge the tripping springs in preparation for the next tripping operation.

5.9.2.4.3 Motor Closing: Motor closing is utilized on some three-phase reclosers. The motor charges the closing springs and forces their overtoggle to close the recloser. The closing spring action simultaneously charges the tripping springs. The motor is energized from an external power supply.

5.9.2.5 Interrupter Types: Reclosers utilize either oil, vacuum, or SF_6 as the interrupting medium.

5.9.2.5.1 Oil Interruption: Oil interruption is utilized on most single-phase and some three-phase reclosers. Reclosers utilizing oil for current interruption use the same oil for basic insulation. Most reclosers with hydraulic control also use the same oil for timing and counting functions.

5.9.2.5.2 Vacuum Interruption: Vacuum interruption is utilized on a few single-phase and some three-phase reclosers. It has the advantages of lower maintenance frequency and minimum external force reaction during interruption. Some vacuum reclosers may utilize oil as the basic insulating medium, depending on the recloser selected.

5.9.2.5.3 SF_6 Interruption: SF_6 interruption is utilized on some three-phase reclosers. In addition to having the same advantages as vacuum interruption, SF_6 is a better insulating medium than oil or air.

NOTE: The term "Type" is a manufacturer's designation to identify each particular group or family of reclosers that it produces. It covers the major classifying features and certain rating and performance characteristics.

RUS IP 202-1 contains a listing of RUS accepted recloser manufacturers, some on conditional basis.

5.9.3 Recloser Ratings

Automatic circuit reclosers are rated in terms of various voltages, frequency, continuous current, minimum tripping current, interrupting current, and making current. In operating a recloser, the limitations imposed by a given recloser rating should not be exceeded in any respect; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

5.9.3.1 Voltage Rating

5.9.3.1.1 <u>Nominal Voltage</u>: Nominal voltage specifies the nominal system voltage to which the recloser is intended to be applied.

5.9.3.1.2 <u>Rated Maximum Voltage</u>: Rated maximum voltage indicates the highest voltage at which the recloser is designed to operate. Voltage ratings of automatic circuit reclosers are shown in ANSI/IEEE Std. C37.60, "IEEE Standard Requirements for Overhead, Pad Mounted, Dry Vault, and Submersible Automatic Circuit Reclosers and Fault Interrupters for AC Systems," (Tables 5-60, 5-61, and 5-62).

NOTE: Some reclosers can be operated at system voltages lower than rated voltage. Series coil, hydraulically operated reclosers can be applied at a lower voltage without modification, and in such cases may gain an increase in interrupting current capability. Non-series coil—shunt coil closing, spring tripping—reclosers can be applied at a lower voltage by installing a closing coil of the appropriate system voltage rating. No change is necessary if the closing coil is low voltage and is supplied from an external ac or dc auxiliary power source. Consult manufacturers and their literature for proper application of reclosers at voltages lower than rated voltage.

5.9.3.1.3 <u>Rated Impulse Withstand Voltage</u>: Rated impulse withstand voltage of reclosers is a performance characteristic specified in ANSI/IEEE Std. C37.60 as a test requirement. This test demonstrates the ability of the recloser to withstand lightning and other fast impulse voltages. The voltage wave is a standard 1.2 x 50 µs wave and may be either positive or negative polarity.

5.9.3.2 Rated Frequency: The rated frequency of reclosers is 60 Hz. Consult the manufacturer if operation at other frequencies is being considered.

5.9.3.3 Rated Continuous Current: The rated continuous current is the magnitude of current in rms amperes that the recloser is designed to carry continuously. The present continuous current ratings of automatic circuit reclosers are shown in ANSI/IEEE Std. C37.60, Tables 5-60, 5-61, and 5-62. In many cases, the basic continuous current rating of a given recloser is limited by the series trip solenoid coil rating installed in the recloser. Therefore, as load current requirement increases, it is only necessary to replace the solenoid coil with one having a larger rating. See ANSI/IEEE Std. C37.60; Tables 5-63, 5-64, and 5-65.

Table 5-60: Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current,
Rated Impulse Withstand Voltage, and Performance Characteristics of Oil Reclosers.
Ref. ANSI/ IEEE Std. C37.60-1981, Table 2. Copyright © 1981. IEEE. All rights reserved.

				Low-Frequency Insulation Level Withstand Test* kV rms		Current Ratings, Amperes		Standard Operating Duty* Percent of Interrupting Rating						
			Rated Impulse Withstand Voltage* (kV) Crest				Symmetrical Interrupting** at Rated Maximum Volts	15 – 20		45 - 55		90 - 100		Total Number of Unit Operations
Line No.	Nominal System Voltage (kV) rms	Rated Maximum Voltage (kV) rms		1 min Dry	10 s Wet	Continuous, 60 Hz		Minimum X/R	Number of Unit Operations	Minimum X/R	Number of Unit Operations	Minimum X/R	Number of Unit Operations	
Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
						Single-Phase Reclosers								
1	14.4	15.0	95	35	30	50	1250	2	40	4	40	8	20	100
2	14.4	15.5	110	50	45	100	2000	2	32	5	24	10	12	68
3	14.4	15.5	110	50	45	280	4000	3	32	6	20	12	12	64
4	14.4	15.5	110	50	45	560	10000	4	28	8	20	15	10	58
5	24.9	27.0	150	60	50	100	2500	2	32	5	24	12	12	68
6	24.9	27.0	150	60	50	280	4000	3	32	6	20	13	12	64
7	34.5	38.0	150	70	60	560	8000	4	28	8	20	15	10	58
						Three-Phase Reclosers								
8	14.4	15.0	95	35	30	50	1250	2	40	4	40	8	20	100
9	14.4	15.5	110	50	45	100	2000	2	32	5	24	10	12	68
10	14.4	15.5	110	50	45	280	4000	3	32	6	20	12	12	64
11	14.4	15.5	110	50	45	400	4000	3	32	6	20	12	12	64
12	14.4	15.5	110	50	45	560	8000	3	28	7	20	14	10	58
13	14.4	15.5	110	50	45	560	16000	4	16	8	8	16	4	28
14	14.4	15.5	110	50	45	560	16000	4	28	8	20	16	10	58
15	14.4	15.5	110	50	45	1120	16000	4	28	8	20	16	10	58
16	24.9	27.0	150	60	50	100	2500	2	32	5	24	12	12	68
17	24.9	27.0	150	60	50	560	8000	4	28	8	20	15	10	58
18	24.9	27.0	150	60	50	1120	8000	4	28	8	20	15	10	58
19	24.9	27.0	150	60	50	560	12000	4	28	8	20	15	10	58
20	34.5	38.0	150	70	60	400	6000	4	28	8	24	15	10	62
21	34.5	38.0	150	70	60	560	16000	4	28	8	20	15	10	58
22	34.5	38.0	150	70	60	1120	12000	4	28	8	20	15	10	58
23	46.0	48.3	250	105	95	560	10000	4	28	8	20	15	10	58
24	69.0	72.5	350	160	140	560	8000	4	28	8	20	16	10	58

*These are performance characteristics specified as test requirements in this standard.
**See Table 3 [Table 5-63] for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

Table 5-61: Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage, and Performance Characteristics of Reclosers with Vacuum Interrupters.
Ref. ANSI/ IEEE Std. C37.60-1981, Table 4. Copyright © 1981. IEEE. All rights reserved.

				Low-Frequency Insulation Level Withstand Test* kV rms		Current Ratings (A)		Standard Operating Duty*						
								Percent of Interrupting Rating						
							Symmetrical Inter-rupting** at	15 – 20		45 – 55		90 - 100		
Line No.	Nominal System Voltage, kV rms	Rated Maximum Voltage, kV rms	Rated Impulse Withstand Voltage,* kV Crest	1 min. Dry	10 s Wet	Contin-uous, 60 Hz	Rated Maximum Volts	Mini-mum X/R	Number of Unit Operations	Mini-mum X/R	Number of Unit Operations	Mini-mum X/R	Number of Unit Operations	Total Number of Unit Operations
Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
						Single-Phase Reclosers								
1	14.4	15.5	110	50	45	200	2000	2	52	5	68	10	18	138
						Three-Phase Reclosers								
2	14.4	15.5	110	50	45	200	2000	2	52	5	68	10	18	138
3	14.4	15.5	110	50	45	400	6000	3	48	7	60	14	16	124
4	14.4	15.5	110	50	45	560	12000	4	44	8	66	15	16	116
5	14.4	15.5	110	50	45	800	12000	4	44	8	56	15	16	116
6	14.4	15.5	110	50	45	560	16000	4	44	8	52	16	16	112
7	14.4	15.5	110	50	45	800	16000	4	44	8	52	16	16	112
8Δ	14.4	15.5	110	50	45	1120	16000	4	44	8	52	16	16	112
9	24.9	27.0	125	60	50	560	10000	3	44	7	56	14	16	116
10Δ	34.5	38.0	150	70	60	560	12000	4	44	8	56	15	16	116

* These are performance characteristics specified as test requirements in this standard.
**See Table 5 [Table 5-64] for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.
Δ These lines have been approved as Suggested Standard for Future Design.
NOTE: The Standard operating duty represents half-life as measured by contact erosion. Refer to the manufacturer's method for determining permissible contact erosion.

Table 5-62: Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage and Performance Characteristics of Pad-Mounted, Dry-Vault and Submersible Reclosers, and Non- Reclosing Fault Interrupters, All with Vacuum Interrupters. Ref. ANSI/ IEEE Std. C37.60-1981, Table 6. Copyright © 1981. IEEE. All rights reserved.

			Rated Impulse Withstand Voltage (kV) Crest	Low-Frequency Insulation Level Withstand Test** kV rms		Current Ratings, (A)		Standard Operating Duty* Percent of Interrupting Rating							
	Nominal System Voltage (kV) rms	Rated Maximum Voltage (kV) rms				Maxi-mum Con-tinuous, 60 Hz	Symmet-rical Inter-rupting at Rated Maximum V	15 – 20		45 - 55		90 - 100		Total Number of Unit Operations	Withstand Test Voltage kV – dc 15 min.
Line No.				1 min Dry	10 s Wet			Mini-mum X/R	Number of Unit Operations	Mini-mum X/R	Number of Unit Operations	Mini-mum X/R	Number of Unit Operations		
Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
Three-Phase Reclosers															
SSFD 1	14.4	15.5	95	35		200	8000	1	44	2	56	4	16	116	53
SSFD 2	14.4	15.5	95	35		560	6000	3	48	7	60	14	16	124	53
3	14.4	15.5	95	35		560	12000	4	44	8	56	15	16	116	53
SSFD 4	14.4	15.5	95	35		560	12000	1	44	2	52	4	16	112	53
SSFD 5	24.9	27.0	125	40		200	16000	1	44	2	52	4	16	112	78
6	24.9	27.0	125	40		560	10000	3	28	7	20	14	10	58	78

* These are performance characteristics specified as test requirements in this standard.

** See Table 7 [Table 5-65] for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

NOTE: This standard operating duty represents half-life as measured by contact erosion. Refer to manufacturer's methods for determining permissible contact erosion.

Table 5-63: Continuous Current and Interrupting Current Ratings of Oil Reclosers.
Ref. ANSI/ IEEE Std. C37.60-1981, Table 3. Copyright © 1981. IEEE. All rights reserved.

	Interrupting Current Rating in Amperes at Rated Maximum Voltage													
	Single-Phase Series Coil Reclosers							Three-Phase Series Coil Reclosers						
Con-tinuous Current Rating (A)	Recloser Line No.							Recloser Line No.						
	1	2	3	4	5	6	7	8	9	10	11	12-17	16	20
	Rated Maximum Voltage, kV													
	15.0	15.5	15.5	15.5	27.0	27.0	38.0	15.0	15.5	15.5	15.5	15-27	27.0	34.0
5	125	200	—	—	200	—	—	125	200	—	—	—	200	—
10	250	400	—	—	400	—	—	250	400	—	—	—	400	—
15	375	600	—	—	600	—	—	375	600	—	—	—	600	—
25	625	1000	1500	—	1000	—	—	625	1000	1500	1500	—	1000	1500
35	875	1400	2100	—	1400	—	—	875	1400	2100	2100	—	1400	2100
50	1250	2000	3000	—	2000	3000	—	1250	2000	3000	3000	—	2000	3000
70	—	2000	4000	—	2500	4000	—	—	2000	4000	4000	—	2500	4200
100	—	2000	4000	6000	2500	4000	6000	—	2000	4000	4000	6000	2500	6000
140	—	—	4000	8400	—	4000	8000	—	—	4000	4000	8000	—	6000
200	—	—	4000	10 000	—	4000	8000	—	—	4000	4000	8000	—	6000
280	—	—	4000	10 000	—	4000	8000	—	—	4000	4000	8000	—	6000
400	—	—	—	10 000	—	—	8000	—	—	—	4000	8000	—	6000
560	—	—	—	10 000	—	—	8000	—	—	—	—	8000	—	—

	Three-Phase Non-Series Coil Reclosers												
Minimum Trip Setting (A)	Recloser Line No.												
	11	12	13	14	15	17	18	19	20	21	22	23	24
	Rated Maximum Voltage, kV												
	15.5	15.5	15.5	15.5	15.5	27.0	27.0	27.0	38.0	38.0	38.0	48.3	72.5
100	3000	—	—	—	—	—	—	—	3000	3000	—	3000	3000
140	4000	—	—	—	—	—	—	—	4200	4200	—	4200	4200
200	4000	6000	6000	6000	—	6000	6000	6000	6000	6000	6000	6000	6000
280	4000	8000	8400	8400	—	8000	8000	8400	6000	8400	8400	8400	8000
400	4000	8000	12 000	12 000	12 000	8000	8000	12 000	6000	12 000	12 000	10 000	8000
560	4000	8000	16 000	16 000	16 000	8000	8000	12 000	6000	16 000	12 000	10 000	8000
800	4000	8000	16 000	16 000	16 000	8000	8000	12 000	6000	16 000	12 000	10 000	8000
1120	—	8000	16 000	16 000	16 000	8000	8000	12 000	—	16 000	12 000	10 000	8000
1600	—	—	—	—	16 000	—	8000	—	—	—	12 000	—	—
2240	—	—	—	—	16 000	—	8000	—	—	—	12 000	—	—

NOTE: For interrupting current ratings at other than rated voltage, consult the manufacturer. The interrupting current ratings of reclosers are not generally on a constant kVA basis.

Table 5-64: Continuous Current and Interrupting Current Ratings of Reclosers
with Vacuum Interrupters.
Ref. ANSI/ IEEE Std. C37.60-1981, Table 5. Copyright © 1981. IEEE. All rights reserved.

	Interrupting Current Rating in Amperes at Rated Maximum Voltage				
	Single-Phase Series Coil Reclosers		Three-Phase Series Coil Reclosers		
Continuous Current Rating, Amperes	Recloser Line No. 1		Recloser Line No. 2	4	9
	Rated Maximum Voltage, kV 15.5		Rated Maximum Voltage, kV 15.5	15.5	27.0
5	200		200	—	—
10	400		400	—	—
15	600		600	—	—
25	1000		1000	—	—
35	1400		1400	—	—
50	2000		2000	3000	3000
70	2000		2000	4200	4200
100	2000		2000	6000	6000
140	2000		2000	8400	8400
200	2000		2000	12000	10000
280	—		—	12000	10000
400	—		—	12000	10000
560	—		—	12000	10000

	Three-Phase Non-Series Reclosers							
	Recloser Line No.							
Minimum Trip Setting, Amperes	3	4	5	6	7	8	9	10
	Rated Maximum Voltage, kV							
	15.5	15.5	15.5	15.5	15.5	15.5	27.0	38.0
100	3000	3000	3000	3000	—	—	3000	3000
140	4200	4200	4200	4200	—	—	4200	4200
200	6000	6000	6000	6000	—	—	6000	6000
280	6000	8400	8400	8400	—	—	8400	8400
400	6000	12 000	12 000	12 000	12 000	12 000	10 000	12 000
500	6000	12000	12000	16000	16000	16000	10000	12000
800	6000	12000	12000	16000	16000	16000	10000	12000
1120	—	12000	12000	16000	16000	16000	10000	12000
1600	—	—	12000	—	16000	16000	—	—
2240	—	—	—	—	16000	—	—	—

NOTE: For interrupting current ratings at other than rated voltage, consult the manufacturer. The interrupting current ratings of reclosers are not generally on a constant kVA basis.

Table 5-65: Continuous Current and Interrupting Current Ratings of Pad-Mounted,
Dry-Vault, and Submersible Reclosers, and Non-Reclosing Fault Interrupters,
All with Vacuum Interrupters. Ref. ANSI/ IEEE Std. C37.60-1981, Table 7.
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Continuous Current Rating (A)	Interrupting Current Rating in Amperes at Rated Maximum Voltage					
	Three-Phase Series Coil Reclosers					
	Recloser Line No.					
	1	2	3	4	5	6
	Rated Maximum Voltage, kV					
			15.5			27.0
50			3000			3000
70			4200			4200
100			6000			6000
140			8400			8400
200			12000			10000
280			12000			10000
400			12000			10000
560			12000			10000

Minimum Trip Setting (A)	Three-Phase Non-series Coil Reclosers					
	Recloser Line No.					
	1	2	3	4	5	6
	Rated Maximum Voltage, kV					
	15.5	15.5	15.5	15.5	27.0	27.0
100	6000	6000	3000	3000	3000	3000
140	8000	3000	4200	4200	4200	4200
200	8000	4200	6000	6000	6000	6000
280	8000	6000	8400	8400	8400	8400
400	8000	6000	12000	12000	12000	10000
560	--	6000	12000	16000	16000	10000
800	--	6000	12000	16000	16000	10000
1120	--	6000	12000	16000	16000	10000

5.9.3.4 Rated Minimum Tripping Current

5.9.3.4.1 The rated minimum tripping current is the minimum current at which a magnetically operated series coil recloser will perform a tripping operation. Standard tripping pickup is 200 percent of the continuous current rating of the recloser coil. Some reclosers are adjustable above or below the standard tripping pickup value.

5.9.3.4.2 The minimum tripping current for shunt trip hydraulically controlled reclosers is as described for series reclosers. With electronically controlled reclosers, the minimum trip rating is variable and has no relation to the rated continuous current. Information on specific reclosers should be obtained from the manufacturer.

The differential between minimum trip and continuous current ratings normally provides sufficient margin for load inrush current pickup after an extended outage on a feeder circuit.

5.9.3.5   Rated Interrupting Current: The rated interrupting current is the maximum rms symmetrical current that a recloser is designed to interrupt under the standard operating duty, circuit voltage, and specified circuit constants. See ANSI/IEEE Std. C37.60, Tables 5-60 through 5-65. This rating is stated on the nameplate. It is based on the capability of reclosers to interrupt the corresponding asymmetrical

current in circuits having minimum X/R values as given in Column 13 of Tables 5-60, 5-61, and 5-62 with a normal frequency recovery voltage equal to the rated maximum voltage of the recloser.

> X/R is the ratio of reactance to resistance of a circuit at rated frequency. The rms value of asymmetrical fault current at any time after initiation of the fault is dependent upon the instantaneous voltage existing at the moment the fault is initiated and upon the decrement of the direct current component, which is determined by the X/R value of the circuit.

Multiplying factors that produce the maximum rms value of asymmetrical current at one-half cycle corresponding to the rated interrupting current can be found in ANSI/IEEE Std. C37.60-1981, Section 5.6, "Rated Symmetrical Interrupting Current," page 17.

5.9.3.6   Rated Making Current: The rated making current is the same value as the rated interrupting current, including the corresponding asymmetry. The recloser has to be capable of closing and latching closed against the rated making current and holding closed until a tripping sequence is initiated.

5.9.4   Construction

Most automatic circuit reclosers consist of five major components: tank, bushings, mechanism, interrupter, and controls. Although Figures 5-46 and 5-47 refer to oil circuit reclosers, many reclosers consist of the same basic components.

5.9.4.1   Tank: The tank is that part of the recloser that houses the interrupter and tripping and closing mechanisms. The tank is usually made of steel and is rectangular for a three-phase recloser and cylindrical for a single-phase recloser. The top is usually an aluminum casting that supports the various components. Some new technologies do not utilize tanks. The interrupter may be enclosed in an epoxy bushing while the operating mechanism is enclosed in a steel housing.

5.9.4.2   Bushings: The bushings are the insulating structures including through-conductors with provision for mounting on the top of the recloser.

5.9.4.3   Operating Mechanism: The operating mechanism of an automatic circuit recloser provides the power to open, close, reclose, lock out, or hold closed the main contacts. The tripping mechanism is the device that releases the holding means and opens the main contacts. In most cases, the opening force is furnished by springs that are charged by the closing mechanism. An operating mechanism is shown in Figure 5-49.

The closing mechanism is a solenoid coil, springs, or a motor and gear arrangement. The closing force serves to close the main contacts and at the same time charges the opening springs. The lockout mechanism is the device that locks the main contacts in the open position following the completion of the sequence of operation. The hold-closed mechanism is the device that holds the main contacts in the closed position following the completion of a predetermined sequence of operation. It holds the main contacts closed as long as current flows in excess of a predetermined value. When the current is reduced below this value, the hold-closed mechanism resets to its initial position.
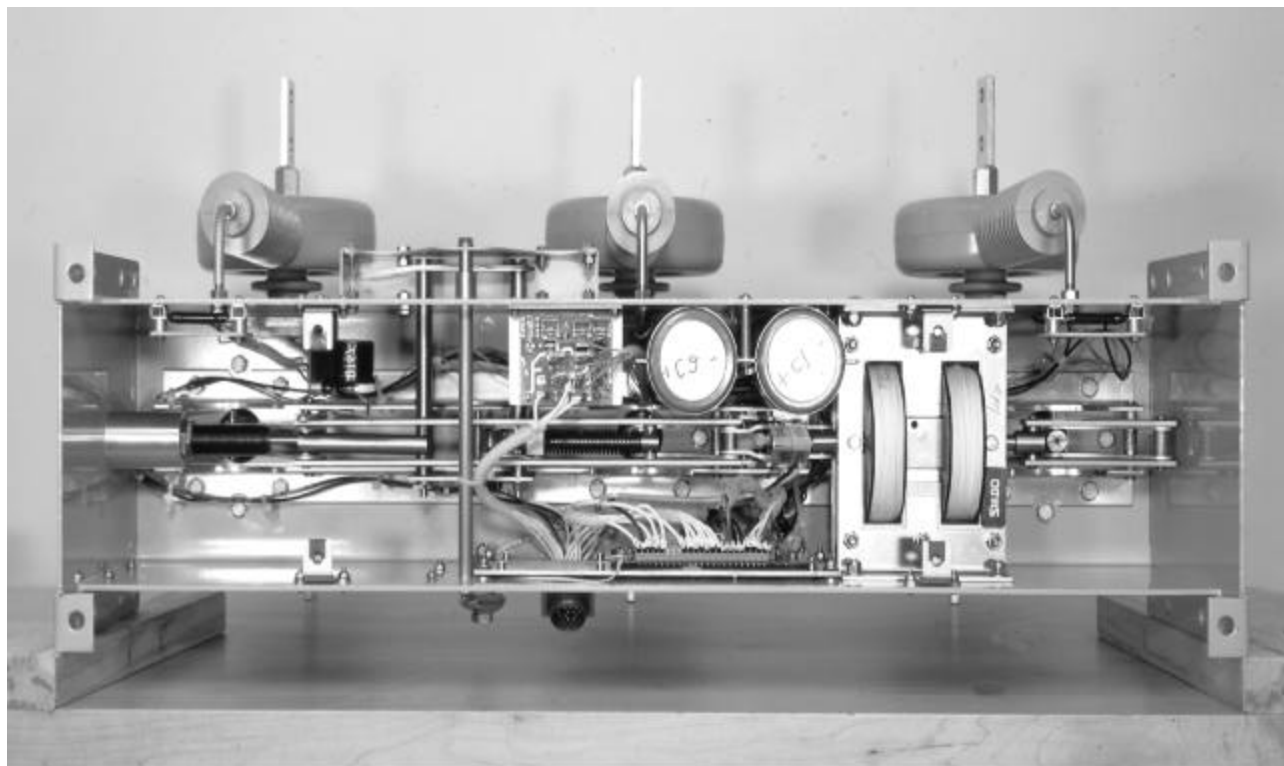
Figure 5-49: Operating Mechanism with Housing Cover Removed.
Courtesy of Cooper Power Systems.

5.9.4.4   Interrupter: The interrupter is that part of the recloser that contains separable contacts that operate within an interrupting unit. The physical configuration and method of interruption vary with manufacturer and recloser classification.

5.9.4.5   Control: Reclosers are provided with sequence control devices and operation integrator to change the recloser from instantaneous operations to time-delay operations and to lock out the recloser after a prescribed number of operations. Individual tripping operations of a recloser can be made to follow instantaneous or time-delay, time–current characteristics. Reclosers are normally set for one of the following sequences of operations:

    a.   Four time-delay operations
    b.   One instantaneous operation followed by three time-delay operations
    c.   Two instantaneous operations followed by two time-delay operations

A number of different sequence control devices may be roughly classed into three types: hydraulic, mechanical, or electronic. In the hydraulic type, an oil pump attached to the recloser plunger raises a trip piston a certain distance with each operation of the recloser. This trip piston establishes the sequence of fast and delayed tripping operations and eventually locks the recloser open. In the mechanical type, the trip piston is mechanically operated by the lift rod one notch at a time to accomplish this sequencing. The electronic type of control utilizes solid-state circuitry to provide the intelligence for performing all the command functions or automatic operation. Consult manufacturers' literature for ratings and available arrangements of electronic components.

5.9.5 Recloser Operation

When an overcurrent of sufficient magnitude flows through the trip coil or sensing current transformers, the tripping action is initiated and the contacts are opened. The recloser contacts then reclose following a predetermined length of time (see Figure 5-50 – ANSI/IEEE Std. C37.60-1981, Fig. 1). By the time the recloser has reassessed the circuit, the sequence control device has moved to count the trip operation. If the fault still persists on the circuit when the recloser closes, the tripping and reclosing sequence is repeated a predetermined number of times, as established by the sequence control device, until the recloser goes to either the lockout or the hold-closed position. If the fault has cleared from the circuit during any open-circuit period, however, the recloser closes and remains closed, and the sequence control device resets so that it is in position for the next sequence of operations (see Figure 5-51).
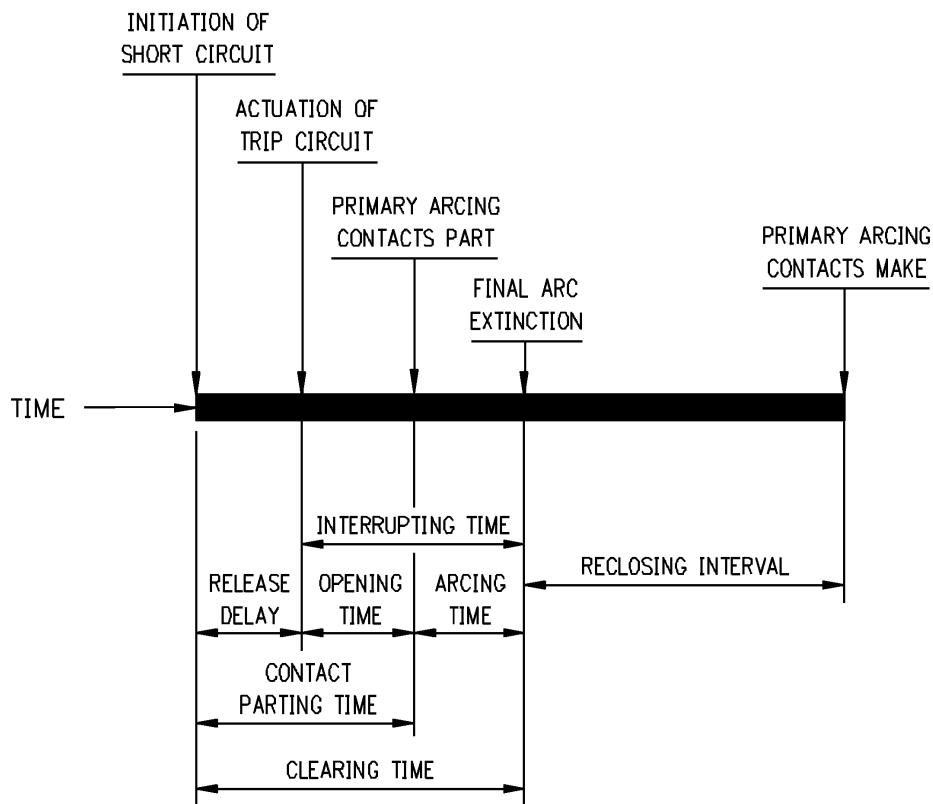
Figure 5-50: Unit Operation. Ref. ANSI/ IEEE Std. C37.60-1981, Figure 1.
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5.9.5.1 Manual Tripping: An automatic circuit recloser can be tripped manually by moving the manual-operating handle to the trip position by means of a hookstick, or by moving the control switch to the trip position if the recloser is provided with remote control. If the recloser has a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is manually tripped.

5.9.5.2 Manual Closing: An automatic circuit recloser can be closed manually by moving the manual-operating handle to the close position by means of a hookstick or, if the recloser is provided with remote
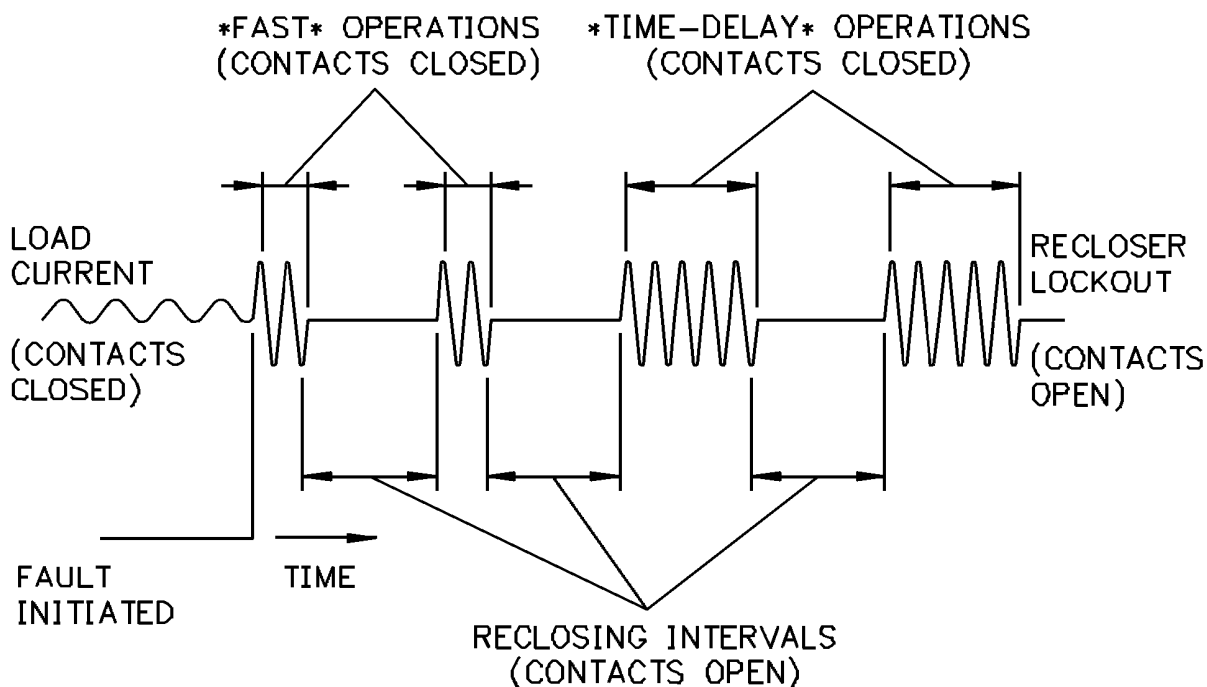
Figure 5-51: Recloser Operating Sequence Upon Occurrence of a Permanent Fault

control, by moving the control switch to the close position. If the recloser has a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is closed manually. After the automatic circuit recloser has been successfully closed, the automatic reclosing should be placed in service.

5.9.5.3 **Manual Reclosing After Lockout Operation:** Many reclosers in service are designed to lock out following a selected sequence of tripping and automatic reclosing operations. The theory behind this type of application is that, if a fault is temporary, it will be cleared during the instantaneous operation of the recloser. If the fault is permanent, the recloser goes into time-delay tripping operation and permits sectionalizing devices, such as fuses beyond the recloser, to open and isolate the fault. If a permanent fault should occur between the recloser and the next sectionalizing device out on the line, the recloser then goes to lockout and isolates the fault.

When a recloser appears to be locked out, the operator is always faced with the possibility that the recloser itself may have failed. The following procedure is recommended for reclosing of the recloser after a lockout operation.

5.9.5.3.1 Make a careful visual inspection for evidence of distress such as throwing of oil or damaged bushings.

5.9.5.3.2 Close the recloser with a hookstick, keeping the hook in the operating ring momentarily so that the recloser can be opened manually in case local trouble or failure becomes evident. If no local trouble develops and the recloser again locks out after going through its proper sequence, it should not be reclosed again until the entire circuit on the load side to all sectionalizing devices has been patrolled and cleared if necessary.

5.9.5.4 **Manual Reclosing After Hold-Closed Operation:** The recloser that is designed for hold-closed operation performs much the same function as the recloser that goes to lockout. It is normally set to trip instantaneously twice to permit a temporary fault to clear. If the fault is permanent, the recloser latches closed to permit the sectionalizing device nearest the fault to operate and isolate the fault. However, a fuse at the recloser opens the circuit when a permanent fault occurs between the hold-closed recloser and the next sectionalizing device out on the line. The fuse in series with the hold-closed recloser is normally installed on the supply side of the recloser so that it also protects against electrical failure in the recloser itself. To reclose a recloser after a hold-closed operation, the following procedure is recommended.

5.9.5.4.1 Make a careful visual inspection for evidence of distress such as throwing of oil or damaged bushings.

5.9.5.4.2 If inspection under Section 5.9.5.4.1 indicates that everything is in order, the operator should first open the recloser with a hookstick, and then replace the fuse and close the cutout to check the recloser on the supply side. If everything is in order, the operator should open the series cutout and close the recloser; then close the series cutout. If there is no local trouble and service is still not restored, then the load side to all sectionalizing devices should be patrolled to determine the cause of the tripout.

5.9.5.5 **Load Pickup:** The inrush current experienced in closing a recloser after a lockout operation may occasionally introduce some difficulties in getting the recloser to latch closed. The highest inrush current can originate from automatic starting motors or magnetizing current of transformers; however, these types of inrush currents are normally short lived (on the order of 3 to 30 cycles). Some makes of reclosers may operate on the instantaneous trip due to this inrush current and may have to open and automatically reclose, until the sequence of operation comes to the time-delay trip, before the recloser will stay closed. Other makes of reclosers, when reclosed after lockout, do not operate on the instantaneous trip but have one time-delay trip operation to lock out, which will normally override the inrush current and pick up the load. A cold-load pickup accessory is available on electronic controls for three-phase reclosers. This accessory temporarily increases the minimum pickup current to a sufficient value (usually double) to override the cold-load inrush current and allow the recloser to latch closed. Careful observation will indicate whether failure to hold the load is caused by a fault or by heavy overload. Instant and perhaps violent action would indicate a fault, whereas some delay might mean overload due to inrush current. In the latter case, sectionalizing to drop part of the load, rather than a patrol, may be necessary. In any case, if nothing is found on patrol, then sectionalizing is indicated.

5.9.6 Maintenance and Inspection

5.9.6.1 **Installation:** Before installing a recloser, check for external mechanical damage, oil level (oil-filled reclosers), operating sequence as specified, and the record reading on the operation counter. Periodic inspection and maintenance are essential to ensure efficient, trouble-free service of an automatic circuit recloser. Once an automatic circuit recloser is installed, it should be placed on a periodic schedule of test and inspection. Frequency of maintenance should be based on the manufacturer's recommendations, elapsed time in service, and number of operations. Many of the new vacuum technologies do not require the frequency of scheduled maintenance that traditional oil circuit reclosers do. Such test and inspection should cover timing tests and checking of bushings for cracks and of the tank for oil leakage, as well as recording the counter reading. Internal inspection should include contact maintenance or replacement; a check of all gears, linkages, timing devices; test of the oil, etc.

5.9.7 Mounting

Most reclosers, both single- and three-phase, are suitable for mounting on poles (see Figure 5-52) and substation structures. Single-phase reclosers can be mounted singularly or in clusters. Three-phase reclosers have mounting frames that are suitable for base mounting, pad-mount enclosure installation, or modification for pole or substation structure mounting.

Figure 5-52: Mounted Recloser. Courtesy of Cooper Power Systems.

5.9.8 References

ANSI Std. C37.61, "IEEE Standard Requirements for Overhead, Pad Mounted, Dry Vault, and Submersible Automatic Circuit Reclosers and Fault Interrupters for AC Systems."

ANSI Std. C42.100, *IEEE Standard Dictionary of Electrical and Electronic Terms*.

ANSI/IEEE Std. C37.60, "Requirements for Automatic Circuit Reclosers for Alternating-Current Systems."

Electrical Distribution – System Protection, 3d ed. Cooper Power Systems, 1990.

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

Shapleigh, D.R., "Economic Feeder Protection with Automatic Circuit Reclosers," *The Line* 76(3): 17.

5.10   INSTRUMENT TRANSFORMERS

5.10.1   General

This section applies to current and inductively coupled voltage transformers of types generally used in the measurement of electricity and in the control of equipment associated with the transmission and distribution of alternating current.

The primary function of an instrument transformer is stated in the definition provided in ANSI/IEEE Std. C57.13: "An instrument transformer is a transformer that is intended to reproduce in its secondary circuit, in a definite and known proportion, the current or voltage of its primary circuit with the phase relations substantially preserved."

Instrument transformers also provide insulation between the primary and secondary circuits and thus simplify the construction of measuring devices and provide safety for personnel using those devices.

Occasionally, instrument transformers serve another duty as bus supports, especially at the higher voltages where the cost of extra bus supports becomes significant. The manufacturer should always be consulted in such applications to determine what externally applied forces the product can withstand.

If necessary, a voltage transformer may be used for supplying power rather than for measurement. In such situations, it is usually possible to place burdens higher than the volt-ampere rating on the secondary circuit without excessive heating and consequent shortening of life. The limit of such burden is known as the Thermal Burden Rating, i.e., "The volt-ampere output that the transformer will supply continuously at rated secondary voltage without causing the specified temperature limits to be exceeded." The voltage transformer's accuracy of transformation will not be maintained for this type of use.

The primary national standard applicable to current and voltage transformers is ANSI/IEEE Std. C57.13, "IEEE Standard Requirements for Instrument Transformers." This standard covers all-important aspects, including terminology, general requirements, ratings, burdens, accuracy, construction, and test code.

5.10.2   Service Conditions

The standard ratings of instrument transformers are based on operation at the thermal rating of the instrument transformer for defined ambient temperature conditions, provided the altitude does not exceed 1000 meters (3300 feet).

Instrument transformers may be used at higher ambient temperatures, at altitudes higher than 1000 meters, or for other unusual conditions if the effects on performance are considered. Consult the manufacturer for specific applications.

5.10.2.1   Altitude: Table 5-33 in Section 5.5.3.5 shows the altitude correction factors to be used to account for the adverse effect of decreased air density on the insulation withstand capability. These correction factors modify the standard insulation classes shown in Table 5-66. A higher standard BIL may be required at high altitudes in order to obtain the insulation required for the voltage used.

The decreased air density at higher altitudes also affects heat dissipation and the permissible loading on instrument transformers. Current transformers may be operated at altitudes greater than 1000 meters if the current is reduced below rated current by 0.3 percent for each 100 meters the altitude exceeds

Table 5-66: Basic Impulse Insulation Levels and Dielectric Tests
Ref. IEEE Std. C57.13-1993, Table 2. Copyright © 1993. IEEE. All rights reserved.

See Table 5-69 for current transformers with the same dielectric test requirements as power circuit breakers.

Maximum System Voltage (kV)	Nominal System Voltage (kV)	BIL and Full Wave Crest (kV) *	Chopped Wave Minimum Time to Crest Flashover (kV) & (μs)		Power Frequency Applied Voltage Test (kV rms)	Wet 60 Hz 10 s Withstand (kV rms)**	Minimum Creepage Distance (in.) & (mm)	
.66	.6	10	12	—	4	—	—	—
1.2	1.2	30	36	1.5	10	6‡	—	—
2.75	2.4	45	54	1.5	15	13‡	—	—
5.6	5	60	69	1.5	19	20‡	—	—
9.52	8.7	75	88	1.6	26	24‡	—	—
15.5	15	95	110	1.8	34	30‡	—	—
15.5	15	110	130	2	34	34	11	(279)
25.5	25	125	145	2.25	40	36‡	15	(381)
25.5	25	150	175	3	50	50	17	(432)
36.5	34.5	200	230	3	70	70	26	(660)
48.3	46	250	290	3	95	95	35	(890)
72.5	69	350	400	3	140	140	48	(1220)
121	115	450	520	3	185	185	66	(1680)
121	115	550	630	3	230	230	79	(2010)
145	138	650	750	3	275	275	92	(2340)
169	161	750	865	3	325	315	114	(2900)
242	230	900	1035	3	395	350	140	(3500)
242	230	1050	1210	3	460	445	170	(4320)
362	345	1300	1500	3	575	—	205	(5210)
550	500	1675	1925	3	750	—	318	(8080)
550	500	1800	2070	3	800	—	318	(8080)
800	765	2050	2360	3	920	—	442	(11200)

* The selection of the lower BIL for a given nominal system voltage for a marked ratio in Tables 5-73 through 5-77 also reduces other requirements as tabulated above. The acceptability of these reduced requirements should be evaluated for the specific instrument transformer design and application.
** For test procedures, see IEEE Std. 21-1976.
‡ These values are requirements for distribution transformer bushings in IEEE C57.12.00-1993.

1000 meters. Voltage transformers may be operated at higher altitudes only after consultation with the manufacturer.

5.10.2.2   Temperature: Table 5-67 provides the limits of temperature rise for instrument transformers, including the average winding temperature and hottest-spot winding temperature rises.

For 30ºC average ambient temperature conditions, the temperature of the cooling air (ambient temperature) does not exceed 40ºC (104ºF), and the average temperature of the cooling air for any 24-hour period does not exceed 30ºC.

Instrument transformers may also be rated for 55ºC ambient temperature for use inside enclosed switchgear, provided the ambient temperature of the cooling air on the inside of enclosed switchgear does not exceed 55ºC. See ANSI Std. C37.20, "Switchgear Assemblies including Metal-Enclosed Bus," and NEMA Std. SG5, "Power Switchgear Assemblies," for further information.

Table 5-67: Limits of Temperature Rise.* Ref. IEEE Std. C57.13-1993, Table 4.

Type of Instrument Transformer	30°C Ambient		55°C Ambient	
	Average Winding Temperature Rise Determined by Resistance Method (°C)	Hottest-Spot Winding Temperature Rise (°C)†	Average Winding Temperature Rise Determined by Resistance Method (°C)	Hottest-Spot Winding Temperature Rise (°C)
55°C Rise	55‡	65	30	40
65°C Rise	65‡	80	40	55
80°C Rise Dry-Type	80	110	55	85

* Temperature rise of current transformers that are a part of high-voltage power circuit breakers or power transformers shall be in accord with ANSI C37.04-1979 or IEEE C57.12.00-1993, respectively.
† Temperature rise of other metallic parts shall not exceed these values.
‡ Temperature rise at the top of the oil in sealed transformers shall not exceed these values.

Current transformers designed for 55°C temperature rise above 30°C ambient temperatures are given a continuous-thermal-current rating factor (RF). The RF is multiplied by the rated current to indicate the current that can be carried continuously without exceeding the standard temperature limitations. Figure 5-53 shows the permissible loading for given average cooling air temperatures and RFs. As an example, a current transformer with an RF of 1.5 could be used at 150 percent of rated current at 30°C average ambient temperature and 100 percent at 60°C average ambient temperature without exceeding the temperature limitations of the current transformer.

Voltage transformers can be operated at higher ambient temperatures only after consultation with the manufacturer.

5.10.3 Accuracy

To be a useful part of a measurement system, instrument transformers have to change the magnitude of the voltage or current that is being measured without introducing any unknown errors of measurement into the system. The accuracy of transformation should, therefore, be either a known value so that the errors can be included in the computation of the overall measurement, or the errors have to be within the limits of a specified small value so they may be disregarded.

The accuracy obtainable with an instrument transformer depends on its design, circuit conditions, and the burden imposed on the secondary. Accuracy is measured in terms of its true value and phase angle under specified operating conditions.

5.10.3.1 Accuracy Classes for Metering Service: Accuracy classes for metering service have been established that limit the transformer correction factor (TCF) to specified values when the metered load has a power factor of 0.6 lagging to 1.0. The standard accuracy classes for metering service and corresponding TCF limits for current and voltage transformers are shown in Table 5-68. Higher accuracy classes (e.g., 0.15) are available from some manufacturers.
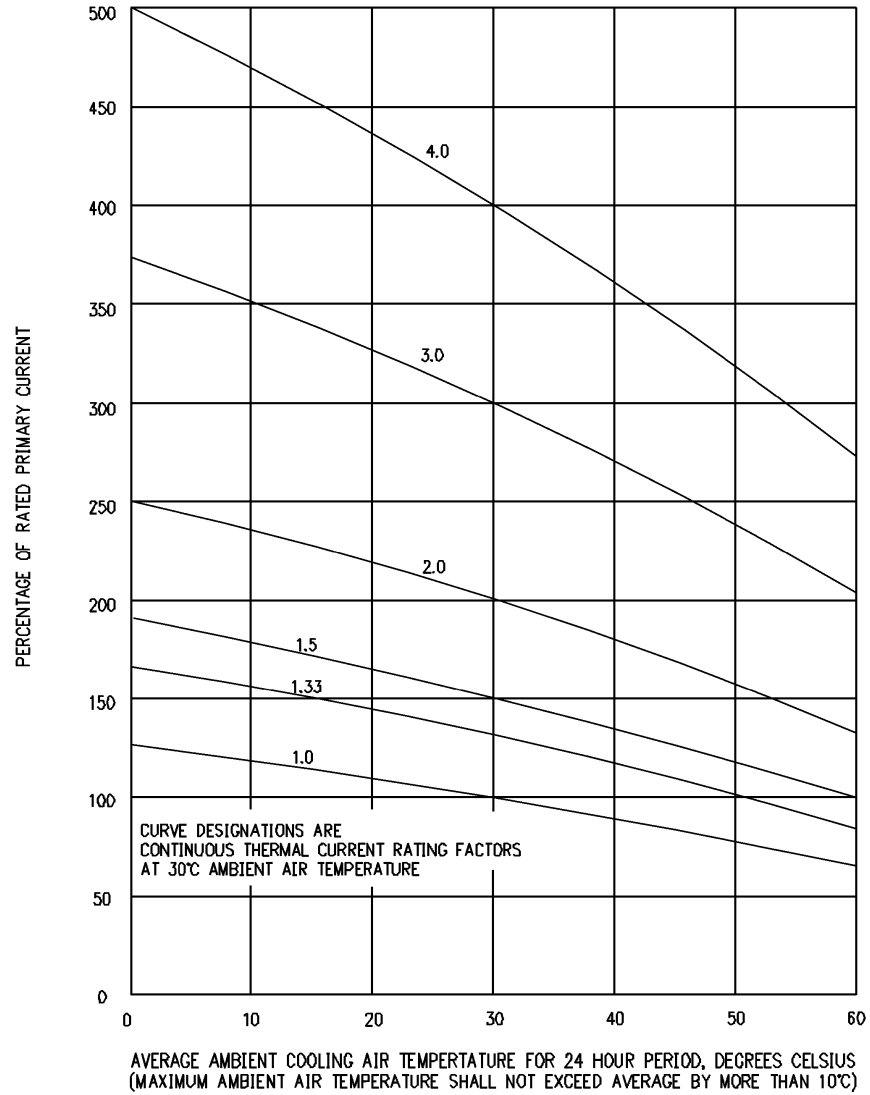
Figure 5-53: 55°C Rise Current Transformer Basic Loading Characteristics (in Air).
Ref. IEEE Std. C57.13-1993, Figure 1.
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Table 5-68: Standard Accuracy Class for Metering Service and Corresponding Limits of
Transformer Correction Factor (0.6 to 1.0 Power Factor (Lagging) of Metered Load).
Ref. IEEE Std. C57.13-1993, Table 6. Copyright © 1993. IEEE. All rights reserved.

| Metering Accuracy Class | Voltage Transformers (At 90 to 100 Percent Rated Voltage) | | Current Transformers | | | |
| | | | At 100% Rated Current* | | At 10% Rated Current | |
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
0.3	0.997	1.003	0.997	1.003	0.994	1.006
0.6	0.994	1.006	0.994	1.006	0.988	1.012
1.2	0.988	1.012	0.988	1.012	0.976	1.024

*   For current transformers the 100 percent rated current limit also applies at the current corresponding to the continuous thermal current rating factor.

5.10.3.2   Transformer Correction Factor: The transformer correction factor for a current or voltage transformer is the ratio correction factor (RCF) multiplied by the phase angle correction factor for a specified primary circuit power factor.

5.10.3.3   Ratio Correction Factor: The ratio correction factor is the ratio of the true ratio to the marked ratio.

5.10.3.4   Phase Angle Correction Factor: The phase angle correction factor is the ratio of the true power factor to the measured power factor. It is a function of both the phase angles of the instrument transformers and the power factor of the primary circuit being measured.

The phase angle correction factor corrects for the phase displacement of the secondary current or voltage, or both, due to the instrument transformer phase angles.

Phase angle of an instrument transformer is the phase displacement, in minutes, between the primary and secondary values.

5.10.4   Secondary Burdens

As defined in ANSI/IEEE Std. C57.13, burden for an instrument transformer is "that property of the circuit connected to the secondary winding that determines the active and reactive power at the secondary terminals. The burden is expressed either as total ohms impedance with the effective resistance and reactive components, or as the total volt-amperes and power factor at the specified value of current or voltage, and frequency."

The burden on the secondary circuit of an instrument transformer affects the accuracy of the device. Accordingly, the burdens of the various meters and other instruments on the secondary have to be known. This information is usually obtained from data sheets issued by the manufacturers.

For many purposes, such as when the burdens are known to be well within the rated burden capability of the transformer, or when accuracy is not a concern, it is sufficient to add arithmetically the volt-ampere burden of the individual devices. If the burden is expressed as an impedance value, the volt-ampere burden can be calculated from the relationship expressed in Equation 5-10:

> Equation 5-10
> $$VA = E^2/Z_b$$

Where:
   E =   Voltage drop across the burden
   Z_b =   Burden impedance

For more accurate purposes, and when the actual burdens approach the limits of the burden rating, the total burden should be determined by adding the individual burdens vectorially (taking power factors into account).

5.10.5   Construction

All instrument transformers have external terminals or leads to which the high-voltage or primary circuit and the secondary circuits are connected. These terminals are marked to indicate the polarity of the

windings.

When letters are used to indicate polarity, the letter H shall be used to distinguish the terminals of the primary winding. The letters X, Y, Z, W, V, U are used to identify the terminals of up to six secondary windings, respectively.

In addition to the letters, each terminal is numbered (e.g., H1, H2, X1, X2). Letters followed by the same number are of the same polarity.

If multiple primary windings are provided, the H terminals are numbered with consecutive pairs of numbers (H1-H2, H3-H4, etc.). The odd-numbered terminals are of the same polarity.

When taps are provided in the secondary windings, the terminals of each winding are numbered consecutively (X1, X2, X3, etc.). The lowest and highest numbered terminals indicate the full winding with intermediate numbers indicating the taps. When the X1 terminals are not in use, the lower number of the two terminals used is the polarity terminal.

5.10.6   Current Transformers

A current transformer is an instrument transformer intended to have its primary winding connected in series with the conductor carrying the current to be measured or controlled. The ratio of primary to secondary current is roughly inversely proportional to the ratio of primary to secondary turns and is usually arranged to produce either five amperes or one ampere (IEC Standard) in the full tap of the secondary winding when rated current is flowing in the primary.

Current transformers can be included in two general categories: metering service and relay service. As a rule, current transformers designed for metering service should not be used for relay applications or system protection. Likewise, current transformers designed for relay service should not be used for high-accuracy metering applications.

Current transformers designed for relay service are fabricated with large cores, which allows the current transformer to replicate the primary current during fault (high primary current) conditions. The large core requires a high exciting current, which limits the accuracy of the current transformer, especially for low primary currents.

Current transformers designed for metering service have smaller cores with small or negligible exciting currents, which enables the current transformer to be highly accurate at normal load currents. However, the smaller core saturates (secondary current is not a replica of the primary current) at currents slightly above rated current. A current transformer designed for metering service may not reliably operate protective devices during fault conditions.

Current transformers can be supplied with single-ratio, dual-ratio, or multi-ratio secondary windings. A multi-ratio current transformer is one from which more than one ratio can be obtained by the use of taps on the secondary winding.

5.10.6.1   Types: Various types of current transformers are available. Figures 5-54 and 5-55 display several types of current transformers.

Figure 5-54: Bushing, Window, and Wound-Type Current Transformers.
Courtesy of Kuhlman Electric – Instrument Transformer Division, Versailles, Kentucky.
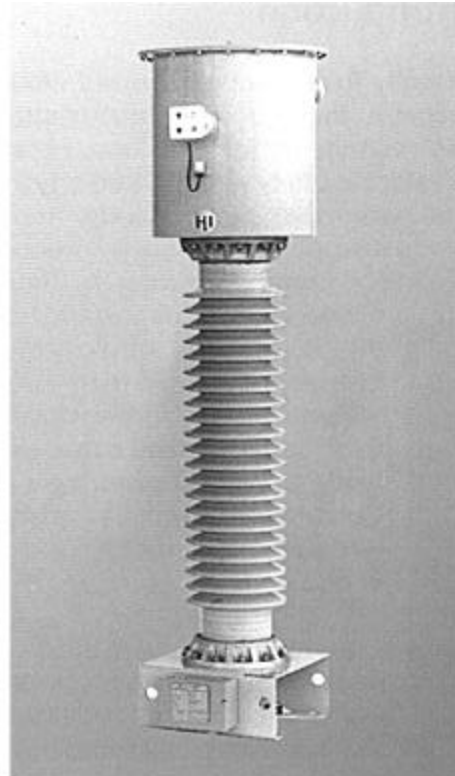
Figure 5-55: High-Voltage Current Transformers.
Courtesy of Haefely Trench, Scarborough, Ontario, Canada

5.10.6.1.1 Bar: A bar-type current transformer is one that has a fixed, insulated straight conductor in the form of a bar, rod, or tube that is a single primary turn passing through the magnetic circuit and that is assembled to the secondary, core, and winding.

5.10.6.1.2 Bushing: A bushing-type current transformer is one that has a round core and a secondary winding insulated from and permanently assembled on the core but has no primary winding or insulation for a primary winding. This type of current transformer is for use with a fully insulated conductor as the primary winding.

5.10.6.1.3 Double-Secondary: A double-secondary current transformer is one that has secondary coils each on a separate magnetic circuit with both magnetic circuits excited by the same primary winding. Multiple-secondary (three or more) current transformers are also manufactured.

5.10.6.1.4 Window/Donut: A window- or donut-type current transformer is one that has a secondary winding insulated from and permanently assembled on the core, but has no primary winding as an integral part of the structure. Complete or partial insulation is provided for a primary winding in the window through which one or more turns of the line conductor can be threaded to provide the primary winding.

5.10.6.1.5 Wound: A wound-type current transformer is one that has a fixed primary winding mechanically encircling the core; it may have one or more primary turns. The primary and secondary windings are completely insulated and permanently assembled on the core as an integral structure.

5.10.6.1.6 Others: Other types are available in addition to those listed. Descriptions can be found in manufacturers' literature.

5.10.6.2 **Ratings:** Ratings are used to specify the operating characteristics and construction of the current transformer. The following paragraphs provide the terms used to express the ratings for current transformers. ANSI/IEEE Std. C57.13 is a source of additional information for some ratings.

5.10.6.2.1 BILs: Basic impulse insulation levels (BILs) in terms of full wave test voltages, nominal system voltages, and maximum line-to-ground system voltages are shown in Tables 5-66 and 5-69. Table 5-69 also provides the BILs, maximum system voltage, and maximum line-to-ground voltages for applications requiring current transformers to have the same dielectric test requirements as power circuit breakers.

Table 5-69: Basic Impulse Insulation Levels and Dielectric Tests for Current Transformers with the
Same Dielectric Test Requirements as Outdoor Power Circuit Breakers.*
Ref. IEEE Std. C57.13-1993, Table 3. Copyright © 1993. IEEE. All rights reserved.

Low Frequency (kV, rms)			Impulse Test 1.2 x 50 µs Wave (kV, Crest)[†]					Minimum Creep Distance	
Rated max.	1 min. dry	10 s wet	Full wave withstand	Interrupter full wave	2 µs withstand	3 µs withstand	Switching impulse insulation level	(mm)	(in.)
121	260	230	550B[‡]	412	710	632	Not req'd	1780	70
145	310	275	650B	488	838	748	Not req'd	2130	84
169	365	315	750B	552	968	862	Not req'd	2490	93
242	425	350	900B	675	1160	1040	Not req'd	3560	140
362	555	Not req'd	1300B	975	1680	1500	825	5310	209
550	860	Not req'd	1800B	1350	2320	2070	1175	8080	318
800	960	Not req'd	2050B	1540	2640	2360	1425	11200	442

*See IEEE Std. C37.09-1979 for impulse and applied potential test procedures.
[†]No flashovers are permitted on current transformers.
[‡]The letter "B" values are established by ANSI C37.06-1987 for current transformers that have the same requirements as power circuit breakers.

5.10.6.2.2   Current Ratings: Current ratings are shown in Table 5-70 (for other than bushing type) and Table 5-71 (multi-ratio bushing type).

Table 5-70: Ratings for Current Transformers with One or Two Ratios.
Ref. IEEE Std. C57.13-1993, Table 7. Copyright © 1993. IEEE. All rights reserved.

		Current Ratings (A)		
Single Ratio		Double Ratio With Series-Parallel Primary Windings	Double Ratio with Taps in Secondary Winding	
10:5	800:5	25 x 50:5	25 / 50:5	
15:5	1200:5	50 x 100:5	50 / 100:5	
25:5	1500:5	100 x 200:5	100 / 200:5	
40:5	2000:5	200 x 400:5	200 / 400:5	
50:5	3000:5	400 x 800:5	300 / 600:5	
75:5	4000:5	600 x 1200:5	400 / 800:5	
100:5	5000:5	1000 x 2000:5	600 / 1200:5	
200:5	6000:5	2000 x 4000:5	1000 / 2000:5	
300:5	8000:5		1500 / 3000:5	
400:5	12 000:5		2000 / 4000:5	
600:5				

Table 5-71: Current Transformer Ratings, Multi-Ratio Type.
Ref. IEEE Std. C57.13-1993, Table 8. Copyright © 1993. IEEE. All rights reserved.

Current Ratings (A)	Secondary Taps	Current Ratings (A)	Secondary Taps
600:5		3000:5	
50:5	X2 - X3	300:5	X3 - X4
100:5	X1 - X2	500:5	X4 – X5
150:5	X1 - X3	800:5	X3 – X5
200:5	X4 – X5	1000:5	X1 – X2
250:5	X3 – X4	1200:5	X2 – X3
300:5	X2 - X4	1500:5	X2 – X4
400:5	X1 – X4	2000:5	X2 – X5
450:5	X3 – X5	2200:5	X1 – X3
500:5	X2 – X5	2500:5	X1 – X4
600:5	X1 – X5	3000:5	X1 – X5
1200:5		4000:5	
100:5	X2 – X3	500:5	X1 – X2
200:5	X1 – X2	1000:5	X3 – X4
300:5	X1 – X3	1500:5	X2 – X3
400:5	X4 – X5	2000:5	X1 – X3
500:5	X3 – X4	2500:5	X2 – X4
600:5	X2 – X4	3000:5	X1 – X4
800:5	X1 – X4	3500:5	X2 – X5
900:5	X3 – X5	4000:5	X1 – X5
1000:5	X2 – X5		
1200:5	X1 – X5		
2000:5		5000:5	
300:5	X3 – X4	500:5	X2 – X3
400:5	X1 – X2	1000:5	X4 – X5
500:5	X4 – X5	1500:5	X1 – X2
800:5	X2 – X3	2000:5	X3 – X4
1100:5	X2 – X4	2500:5	X2 – X4
1200:5	X1 – X3	3000:5	X3 – X5
1500:5	X1 – X4	3500:5	X2 – X5
1600:5	X2 – X5	4000:5	X1 – X4
2000:5	X1 – X5	5000:5	X1 – X5

5.10.6.2.3   Standard Burdens: Standard burdens for current transformers are shown in Table 5-72.
The first five burdens listed are burdens for which metering accuracy classes have been assigned, and the
last four are for relay accuracy.

5.10.6.2.4   Accuracy Ratings: Accuracy ratings are given for each standard burden for which the
current transformer is designed. Table 5-68 lists the accuracy classes and corresponding limits for
transformer correction factors for current transformers for metering service.

For example, the accuracy rating of a current transformer for metering service might be 0.3B-0.1 and
B-0.2, and 0.6B-0.5. Based on these ratings, the transformer will maintain 0.3 accuracy class limits for
standard burdens of B-0.1 and B-0.2 and maintain 0.6 accuracy class limits for a standard burden of
B-0.5. The standard metering burdens, with the characteristics shown by Table 5-72, are 0.1, 0.2, 0.5,
0.9, and 1.8.

Table 5-72: Standard Burdens for Current Transformers with 5 A Secondaries.*
Ref. IEEE Std. C57.13-1993, Table 9. Copyright © 1993. IEEE. All rights reserved.

Burden Designation†	Resistance (Σ)	Inductance (mH)	Impedance (Σ)	Volt-Amperes (at 5 A)	Power Factor
		Metering Burdens			
B-0.1	0.09	0.116	0.1	2.5	0.9
B-0.2	0.18	0.232	0.2	5.0	0.9
B-0.5	0.45	0.580	0.5	12.5	0.9
B-0.9	0.81	1.04	0.9	22.5	0.9
B-1.8	1.62	2.08	1.8	45.0	0.9
		Relaying Burdens			
B-1	0.5	2.3	1.0	25	0.5
B-2	1.0	4.6	2.0	50	0.5
B-4	2.0	9.2	4.0	100	0.5
B-8	4.0	18.4	8.0	200	0.5

* If a current transformer is rated at other than 5 A, ohmic burdens for specification and rating may be derived by multiplying the resistance and inductance of the table by $[5/(\text{ampere rating})]^2$, the VA at rated current and the power factor remaining the same.
† These standard burden designations have no significance at frequencies other than 60 Hz.

5.10.6.2.5 Relay Accuracy: Relay accuracy ratings (or classes) are designated by a classification and a secondary voltage terminal rating as follows:

   a. C or K classification means the transformer ratio can be calculated according to ANSI/IEEE Std. C57.13, Paragraph 8.1.10. In other words, the true ratio of the transformer (primary current to secondary current) can be readily determined for each application using the marked ratio and typical excitation curves.
   b. T classification means the transformer ratio have to be determined by test. The manufacturer has to supply test data to determine performance.
   c. The secondary terminal voltage rating is the voltage that the transformer will deliver to a standard burden listed in Table 5-72 at 20 times normal secondary current (and also at any current from 1 to 20 times rated current at any lesser burden) without exceeding 10 percent ratio error.

For example, relay accuracy class C400 means that the ratio can be calculated and that the ratio error will not exceed 10 percent at any current from 1 to 20 times normal secondary current if the burden does not exceed 4.0 ohms (4.0 ohms x 5 amperes x 20 times normal current = 400 volts).

Standard secondary terminal voltage ratings are 10, 20, 50, 100, 200, 400, and 800 volts.

5.10.6.2.6 Tapped Secondary or Multi-Ratio Current Transformer: For current transformers with tapped secondaries or multi-ratio secondaries, the accuracy class applies only to the full secondary winding unless specifically stated otherwise. Performance on lower taps may be significantly reduced and limited. Use of the lower taps should be avoided if possible.

5.10.6.2.7 Continuous Thermal Current Rating Factors: Continuous thermal current rating factors shall be 1.0, 1.33, 1.5, 2.0, 3.0, or 4.0, based on 30ºC ambient temperature.

5.10.6.2.8 Short-Time Current Ratings: Short-time current ratings (mechanical and thermal) are described in ANSI/IEEE Std. C57.13, Paragraph 6.6. The ratings represent the short-time (typically

1 second) primary current the current transformer can withstand with the secondary windings short circuited without damage or exceeding temperature limitations.

5.10.6.3 Open-Circuit Secondary Voltage: Dangerously high voltages (more than 3500 volts for Class 1) can exist at the open circuit of current transformer secondary circuits, and appropriate measures have to be taken for safety and insulation withstand capability. Always short the secondary windings of current transformers when not in use.

5.10.6.4 Application Data Required for Metering Service: The following information has to be available for calculating the performance of current transformers for metering service:

- Typical ratio correction factor and phase angle curves for the standard burdens for which accuracy ratings are assigned
- Mechanical and thermal short-time ratings

5.10.6.5 Application Data Required for Relaying Service: The following information has to be available for calculating the performance of current transformers for relaying service:

- Relaying accuracy classification
- Mechanical and thermal short-time ratings
- Resistance of secondary winding to determine value for each published ratio
- For Class C and K transformers, typical excitation curves
- For Class T transformers, typical overcurrent ratio curves

5.10.7 Voltage Transformers

A voltage transformer or potential transformer is an instrument transformer intended to have its primary winding connected in shunt with a power supply circuit, the voltage of which is to be measured or controlled.

5.10.7.1 Types: There are several types of voltage transformers available. Figure 5-56 displays several voltage transformers.

5.10.7.1.1 A cascade-type voltage transformer is a single high-voltage line terminal voltage transformer with the primary winding distributed on several cores with the cores electromagnetically coupled by coupling windings and the secondary winding on the core at the neutral end of the high-voltage winding. Each core of this type of transformer is insulated from the other cores and is maintained at a fixed potential with respect to ground and the line-to-ground voltage.

5.10.7.1.2 A double-secondary voltage transformer is one that has two secondary windings on the same magnetic circuit insulated from each other and the primary. Either or both of the secondary windings may be used for measurements or control.

5.10.7.1.3 A grounded-neutral, terminal-type voltage transformer is one that has the neutral end of the high-voltage winding connected to the case or mounting base.

5.10.7.1.4 An insulated-neutral, terminal voltage transformer is one that has the neutral end of the high-voltage winding insulated from the case or base and connected to a terminal that provides insulation for a lower voltage insulation class than required for the rated insulation class of the transformer.

Figure 5-56: Voltage Transformers.
Courtesy of Kuhlman Electric, Instrument Transformer Division, Versailles, Kentucky.

5.10.7.1.5   A single high-voltage line, terminal voltage transformer is one that has the line end of the primary winding connected to a terminal insulated from ground for the rated insulation class. The neutral end of the primary winding may be connected as described in Sections 5.10.7.1.3 or 5.10.7.1.4.

5.10.7.1.6   A two-high-voltage line, terminal voltage transformer is one that has both ends of the high-voltage winding connected to separate terminals that are insulated from each other, and from other parts of the transformer, for the rated insulation class of the transformer.

5.10.7.2   Ratings: The following paragraphs describe the terms and figures used to express the ratings of voltage transformers.

5.10.7.2.1   BILs in terms of full wave test voltages, primary voltage ratings, and marked ratios are shown in Tables 5-73 through 5-77.

The standard voltage transformers listed in the tables are divided into Groups 1, 2, 3, 4, and 5.

Group 1: Designed for 100 percent of rated primary voltage across the primary winding when connected line-to-line, line-to-ground, or line-to-neutral.

Group 2: Designed for line-to-line service, but may be used line-to-ground or line-to-neutral at a voltage across the primary winding equal to the rated line-to-line voltage divided by $\sqrt{3}$. This restriction is due to insulation limitations from line to ground.

Group 3: Designed for line-to-ground service only and having two secondaries. The neutral terminal may be an insulated or grounded type.

Group 4: Designed for line-to-ground service in indoor applications only. The neutral terminal may be an insulated or grounded type.

Group 5: Designed for line-to-ground service only in outdoor applications. The neutral terminal may be an insulated or grounded type. Similar to Group 3 except single ratio and includes lower voltage classes.

Table 5-73: Ratings and Characteristics of Group 1 Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 10.

Group 1 voltage transformers are for application with 100 percent of rated primary voltage across the primary winding when connected line-to-line or line-to-ground. (For typical connections, see Figs 6A and 6B in IEEE C57.13-1993.)

Group 1 transformers shall be capable of operation at 125 percent of rated voltage on an emergency basis (this capability does not preclude the possibility of ferroresonance), provided the burden, in volt-amperes at rated voltage, does not exceed 64 percent of the thermal burden rating, without exceeding the following average winding temperatures: 105°C for 55°C rise types, 115°C for 65°C rise types, and 130°C for 80°C rise types. This will result in a reduction of life expectancy.

Rated Primary Voltage for Rated Voltage Line-to-Line (V)	Marked Ratio	Basic Impulse Insulation Level (kV Crest)
120 for 208Y	1:1	10
240 for 416Y	2:1	10
300 for 520Y	2.5:1	10
120 for 208Y	1:1	30
240 for 416Y	2:1	30
300 for 520 T	2.5:1	30
480 for 832Y	4:1	30
600 for 1040Y	5:1	30
2400 for 4160Y	20:1	60
4200 for 7280Y	35:1	75
4800 for 8320Y	40:1	75
7200 for 12 470Y	60:1	110 or 95
8400 for 14 560"Y	70:1	110 or 95

NOTE: Voltage transformers connected line-to-ground on an ungrounded system cannot be considered to be grounding transformers and should not be operated with the secondaries in closed delta because excessive currents may flow in the delta.

Table 5-74: Ratings and Characteristics of Group 2 Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 11.
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Group 2 voltage transformers are primarily for line-to-line service, and may be applied line-to-ground or line-to-neutral at a winding voltage equal to the primary voltage rating divided by $\sqrt{3}$. (For typical connections, see Figs. 6C and 6D in IEEE C57.13-1993.)

Rated Primary Voltage for Rated Voltage Line-to-Line (V)	Marked Ratio	Basic Impulse Insulation Level (kV Crest)
120 for 120Y	1:1	10
240 for 240Y	2:1	10
300 for 300Y	2.5:1	10
480 for 480Y	4:1	10
600 for 600Y	5:1	10
2400 for 2400Y	20:1	45
4800 for 4800Y	40:1	60
7200 for 7200Y	60:1	75
12 000 for 12 000Y	100:1	110 or 95
14 400 for 14 400Y	120:1	110 or 95
24 000 for 24 000Y	200:1	150 or 125
34 500 for 34 500Y	300:1	200 or 150
46 000 or 46 000Y	400:1	250
69 000 for 69 000Y	600:1	350

NOTE: Voltage transformers connected line-to-ground on an ungrounded system cannot be considered to be grounding transformers and should not be operated with the secondaries in closed delta because excessive currents may flow in the delta.

Table 5-75: Ratings and Characteristics of Group 3 Outdoor Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 12. Copyright © 1993. IEEE. All rights reserved.

Group 3 voltage transformers are for line-to-ground connection only and have two secondaries. They may be insulated-neutral- or grounded-neutral-terminal type.

Ratings through 161 000 Grd Y/92 000 shall be capable of the $\sqrt{3}$ times rated voltage (this does not preclude the possibility of ferroresonance) for 1 min. without exceeding 175°C temperature rise for copper conductor or 125°C rise for EC aluminum. Ratings 230 000 Grd Y /138 000 and above shall be capable of operation at 140 percent of rated voltage with the same limitation of time and temperature. (For typical connections, see Fig. 6E of IEEE C57.13-1993.) Group 3 transformers shall be capable of continuous operation at 110 percent of rated voltage, provided the burden in volt-amperes at this voltage does not exceed the thermal burden rating.

Rated Voltage (V)	Marked Ratio	Basic Impulse Insulation Level (kV Crest)
24 940 Grd Y/14 400	120/200 and 120/200:1	150 or 125
34 500 Grd Y/20 125	175/300 and 175/300:1	200
46 000 Grd Y/27 600	240/400 and 240/400:1	250
69 000 Grd Y/40 250	350/600 and 350/600:1	350
115 000 Grd Y/69 000	600/1000 and 600/1000:1	550 or 450
138 000 Grd Y/80 500	700/1200 and 700/1200:1	650 or 550
161 000 Grd Y/92 000	800/1400 and 800/1400:1	750 or 650
230 000 Grd Y/138 000	1200/2000 and 1200/2000:1	1050 or 900
345 000 Grd Y/207 000*	1800/3000 and 1800/3000:1	1300 or 1175
500 000 Grd Y/287 500*	2500/4500 and 2500/4500:1	1800 or 1675
750 000 Grd Y/431 250*	3750/6250 and 3750/6250:1	2050

 * The higher figures 362 000, 550 000, and 800 000 are the maximum rated primary voltage values as designated for use with extra-high-voltage systems by the ANSI C92 Committee.

NOTES:
(1) The double voltage ratio is usually achieved by a tap in the secondary; in such cases the nonpolarity terminal of the winding shall be the common terminal.
(2) Voltage transformers connected line-to-ground on an ungrounded system cannot be considered to be grounding transformers and should not be operated with the secondaries in closed delta because excessive currents may flow in the delta.

Table 5-76: Ratings and Characteristics of Group 4 Indoor Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 13. Copyright © 1993. IEEE. All rights reserved.

Group 4 voltage transformers are for line-to-ground connection only. They may be insulated-neutral- or grounded-neutral-terminal type. (For typical connections of Group 4A, see Fig. 6f. For typical connections of Group 4B, see Fig. 6g in IEEE C57.13-1993.)

Group 4 voltage transformers shall be capable of continuous operation at 110 percent of rated voltage, provided the burden, in volt-amperes at this voltage, does not exceed the thermal burden rating. Group 4A voltage transformers shall be capable of operation at 125 percent of rated voltage on an emergency basis (this capability does not preclude the possibility of ferroresonance), provided the burden, in volt-amperes at rated voltage, does not exceed 64 percent of the thermal burden rating, without exceeding the following winding temperatures: 105°C for 55°C rise types, 115°C for 65°C rise types, and 130°C for 80°C rise types. (This will result in a reduction of normal life expectancy.) The manufacturer may be consulted for information about a possible higher rating.

Rated Primary Voltage for Rated Voltage Line-to-Line (V)	Marked Ratio	Basic Impulse Insulation Level (kV Crest)
Group 4A: For Operation at Approximately 100 Percent of Rated Voltage		
4160 Grd Y/2400	20:1	60
7200 Grd Y/4200	35:1	75
8320 Grd Y/4800	40:1	75
12 470 Grd Y/7200	60:1	110 or 95
14 560 Grd Y/8400	70:1	110 or 95
Group 4B: For Operation at Approximately 58 Percent of Rated Voltage		
4160 Grd Y/4200	35:1	60
4800 Grd Y/4800	40:1	60
7200 Grd Y/7200	60:1	75
12 000 Grd Y/12 000	100:1	110 or 95
14 400 Grd Y/14 400	120:1	110 or 95

NOTE: Voltage transformers connected line-to-ground on an ungrounded system cannot be considered to be grounding transformers and should not be operated with the secondaries in closed delta because excessive currents may flow in the delta.

Table 5-77: Ratings and Characteristics of Group 5 Outdoor Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 14. Copyright © 1993. IEEE. All rights reserved.

Group 5 voltage transformers are for line-to-ground connection only, and are for use outdoors on grounded systems. They may be insulated-neutral- or grounded-neutral-terminal type. They shall be capable of operation at 140 percent of rated voltage for 1 min. without exceeding 175°C temperature rise for copper conductor or 125°C rise for EC aluminum conductor (this will result in a reduction of normal life expectancy). (For typical connections see Fig. 6h in IEEE C57.13-1993.)
Group 5 voltage transformers shall be capable of continuous operation at 110 percent of rated voltage, provided the burden, in volt-amperes at this voltage, does not exceed the thermal burden rating. This capability does not preclude the possibility of ferroresonance.

Rated Primary Voltage for Rated Voltage Line-to-Line (V)	Marked Ratio	Basic Impulse Insulation Level (kV Crest)
7200 for 12 470 Gnd Y	60:1	110
8400 for 14 560 Gnd Y	70:1	110
12 000 for 20 800 Gnd Y	100:1	150 or 125
14 400 for 25 000 Gnd Y	120:1	150 or 125
20 125 for 34 500 Gnd Y	175:1	200 or 150

Typical primary connections for the voltage transformers of Groups 1, 2, and 3 are shown in Figure 5-57.

5.10.7.2.2   A voltage transformer shall be assigned an accuracy class rating (see ANSI/IEEE Std. C57.13) for each of the standard burdens for which it is designed. For example, an accuracy rating may be 0.3W and X, 0.6Y, and 1.2Z. The values 0.3, 0.6, and 1.2 indicate the accuracy class and represent the percent deviation (maximum and minimum) from the rated voltage. The designations W, X, Y, and Z are standard burdens.

Standard burdens for voltage transformers for accuracy rating purposes are given in Table 5-78. The burdens are expressed in volt-amperes at a specified power factor at either 120 or 69.3 volts.

Table 5-78: Standard Burdens for Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Table 15. Copyright © 1993. IEEE. All rights reserved.

	Characteristics on Standard Burdens*		Characteristics on 120 V Basis			Characteristics on 69.3 V Basis		
Designation	Volt-Amperes	Power Factor	Resistance (Ω)	Inductance (H)	Impedance (Ω)	Resistance (Ω)	Inductance (H)	Impedance (Ω)
W	12.5	0.10	115.2	3.04	1152	38.4	1.01	384
X	25	0.70	403.2	1.09	576	134.4	0.364	192
M	35	0.20	82.3	1.07	411	27.4	0.356	137
Y	75	0.85	163.2	0.268	192	54.4	0.0894	64
Z	200	0.85	61.2	0.101	72	20.4	0.0335	24
ZZ	400	0.85	30.6	0.0503	36	10.2	0.0168	12

*   These burden designations have no significance except at 60 Hz.
NOTE: For rated secondary voltages from 108 V through 132 V or from 62.4 V through 76.2 V, the standard burdens for accuracy tests within ±10% of rated voltage are defined by the characteristic burden impedances at 120 V or 69.3 V respectively. For other rated secondary voltages, the standard burdens for accuracy tests within ±10% of rated voltage are defined by the characteristic burden volt-amperes and power factor. The characteristic volt-amperes apply at rated secondary voltage and appropriate impedances are required. When transformers with rated secondary volts from 108 V through 132 V are tested at secondary voltages within ±10% of ½ times rated voltage, the standard burdens for accuracy tests are defined by the characteristic burdens impedances at 69.3 V. When transformers with other rated secondary volts are to be tested at secondary voltages within ±10% of 1/13 times rated voltage, the standard burdens for accuracy tests are defined by the characteristic burden volt-amperes and power factor. The characteristic volt-amperes apply at 1/13 times rated voltage, for a given standard burden; the burden impedances are lower and the changes in accuracy resulting from burden current are greater than at rated voltage.

NOMINAL 3-PHASE SYSTEMS

VOLTAGE TRANSFORMERS
GROUP 1-2400/4160Y

**2400 V SYSTEM-
NEUTRAL
GROUNDED OR
UNGROUNDED**

2400 V   2400 V
2400 V

(A)

THE ABOVE
TRANSFORMERS
MAY BE CONNECTED
LINE TO LINE ON
A 2400 V SYSTEM

OR

**4160 V WYE SYSTEM-
NEUTRAL
GROUNDED OR
4 WIRE**

4160 V 4160 V
4160 V   2400 V 2400 V
2400 V

(B)

LINE TO NEUTRAL
ON A 4160 V
SYSTEM

GROUP 2 RATED VOLTAGE 14,400 V

14 400 V   14 400 V
14 400 V

(C)

**2400 V SYSTEM-
NEUTRAL
GROUNDED OR
UNGROUNDED**

THE ABOVE
TRANSFORMERS
MAY BE CONNECTED
LINE TO LINE ON
A 14 400 V SYSTEM
BUT ARE LIMITED
BY INSULATION

TO

14 400 V   14 400 V
14 400 V   8314 V
8314 V
8314 V

(D)

LINE TO NEUTRAL
CONNECTION ON
THE SAME SYSTEM

GROUP 3 RATED VOLTAGE 69 000 GRD Y/40 250

**69 000 WYE
SYSTEM-
NEUTRAL
GROUNDED OR
UNGROUNDED**

69 000 V   69 000 V
69 000 V   39 837 V
39 837 V
39 837 V

(E)

ONE PRIMARY
TERMINAL OF EACH
TRANSFORMER
IS NOT FULLY
INSULATED AND
MUST BE CONNECTED
TO GROUND

Figure 5-57: Typical Primary Connections for Voltage Transformers.
Ref. IEEE Std. C57.13-1993, Figures 6 A, B, C, D & E. Copyright © 1993. IEEE. All rights reserved.

Accuracy classes are based on the requirement that the transformer correction factor shall be within specified limits when the power factor of the metered load has any value from 0.6 lag to 1.0, from zero burden to the specified standard burden and at any voltage from 90 to 110 percent of the rated transformer voltage. Accuracy classes and corresponding limits of TCF are shown in Table 5-68.

5.10.7.2.3   The thermal burden rating of a voltage transformer shall be specified in terms of the maximum burden that the transformer can carry at rated secondary voltage without exceeding the temperature rise above 30°C (86°F) ambient permitted by Table 5-67.

5.10.7.3   Application Data: The following information has to be obtained from the manufacturer to accurately determine operating characteristics and limits:

- Typical ratio and phase angle curves for rated primary voltage, plotted for the standard burdens and for the same numerical burdens with unity power factor, from zero burden to the maximum standard burden volt-amperes of the transformer
- Accuracy ratings for all standard burdens up to and including the maximum standard burden rating of the transformer
- Thermal burden rating

5.10.8   Combination Units

5.10.8.1   Combined Instrument Transformers: Combined instrument transformers, sometimes called metering units, include a voltage transformer and current transformer in a single free-standing unit. These units are used primarily in metering applications where a dedicated voltage transformer and current transformer are used for revenue metering.

Each instrument transformer in the combined instrument transformer has to meet the requirements and ratings of ANSI/IEEE Std. C57.13 for the application. Ratings are provided for each instrument transformer in the combined unit.

These units have the advantage of cost savings by eliminating a set of support structures and foundations and reducing substation space requirements. A disadvantage of the combined instrument transformers is a failure of one component requires the entire unit to be removed from service and repaired or replaced.

5.10.8.2   Power Voltage Transformers: Another type of combination unit called a power voltage transformer combines an auxiliary power transformer with instrument voltage transformers.

A common primary winding is included with multiple secondary windings in a single free-standing unit. One or more of the secondary windings are rated for power application, typically 10 kVA to 100 kVA. Additional secondary windings are also included and can be rated either metering or relay accuracy classes with standard burdens as given in Table 5-78.

The advantage of these devices is cost saving by eliminating a set of support structures and reducing space requirements. The devices are also useful at remote switching stations or high-voltage substations where no local distribution service is available for station service. One disadvantage of the power voltage transformer is the loss of accuracy in the metering or relaying secondary windings when the power secondary winding is loaded. Consult the manufacturer to determine the effects of power winding load on the performance of the voltage transformer.

5.10.9 <u>Tests</u>

5.10.9.1   Routing Tests: Paragraph 4.7.2 of ANSI/IEEE Std. C57.13 lists the minimum routine tests an instrument transformer receives at the factory to ensure the instrument transformer meets the specified requirements. The routine tests include applied potential dielectric tests, induced potential tests, accuracy tests, and polarity checks. Additional tests are performed by the manufacturer for each transformer design (type tests) and are not performed on every transformer. These tests are listed in ANSI/IEEE Std. C57.13, Paragraph 4.7.3.

5.10.9.2   Test Procedures: Section 8 of ANSI/IEEE Std. C57.13 describes the methods recommended for testing an instrument transformer. Although most of these tests are usually performed only in the factory, there may be occasions when the user will perform some of them in the user's own testing facility or in the field. It is recommended that Section 8 be consulted for guidance and precautions whenever such tests are planned.

5.10.10 <u>References</u>

ANSI Std. C37.04, "Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

ANSI Std. C37.06, "Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis—Preferred Ratings and Related Required Capabilities."

ANSI Std. C37.20, "Switchgear Assemblies Including Metal-Enclosed Bus."

ANSI/IEEE Std. C57.13, "Standard Requirements for Instrument Transformers."

ANSI/IEEE Std. C57.13.1, "Guide for Field Testing of Relaying Current Transformers."

ANSI/IEEE Std. C57.13.2, "Conformance Test Procedures for Instrument Transformers."

ANSI/IEEE Std. C57.13.3, "Guide for the Grounding of Instrument Transformer Secondary Circuits and Cases."

IEEE Std. 37.09, "Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis."

IEEE Std. C57.12.00, "IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers."

NEMA Std. SG 5, "Power Switchgear Assemblies."

5.11   COUPLING CAPACITORS AND COUPLING CAPACITOR VOLTAGE TRANSFORMERS

5.11.1   General

Both coupling capacitors and coupling capacitor voltage transformers are single-phase devices that utilize one or more capacitor units, usually mounted on a base, to couple a communication signal to a high-voltage power line.

Coupling capacitors (CCs) are used in conjunction with line traps and line tuners for power line carrier (PLC) communication over high-voltage power lines. A CC with an electromagnetic unit is called a Coupling Capacitor Voltage Transformer (CCVT). CCVTs can be used to supply voltage for metering and protection applications similar to a voltage transformer.

The ANSI Standard applicable to the power line coupling capacitors is ANSI Std. C93.1, "Power Line Coupling Capacitors and Coupling Capacitor Voltage Transformers (CCVT) Requirements." This standard covers such items as definitions, service conditions, ratings, testing, and manufacturing requirements.

5.11.2   Coupling Capacitors

Coupling capacitors are primarily used for coupling power line carrier communication equipment to a high-voltage power line. A coupling capacitor used for power line carrier coupling is shown schematically in Figure 5-58. As indicated in Figure 5-58, a coupling capacitor will usually consist of the following equipment and accessories.
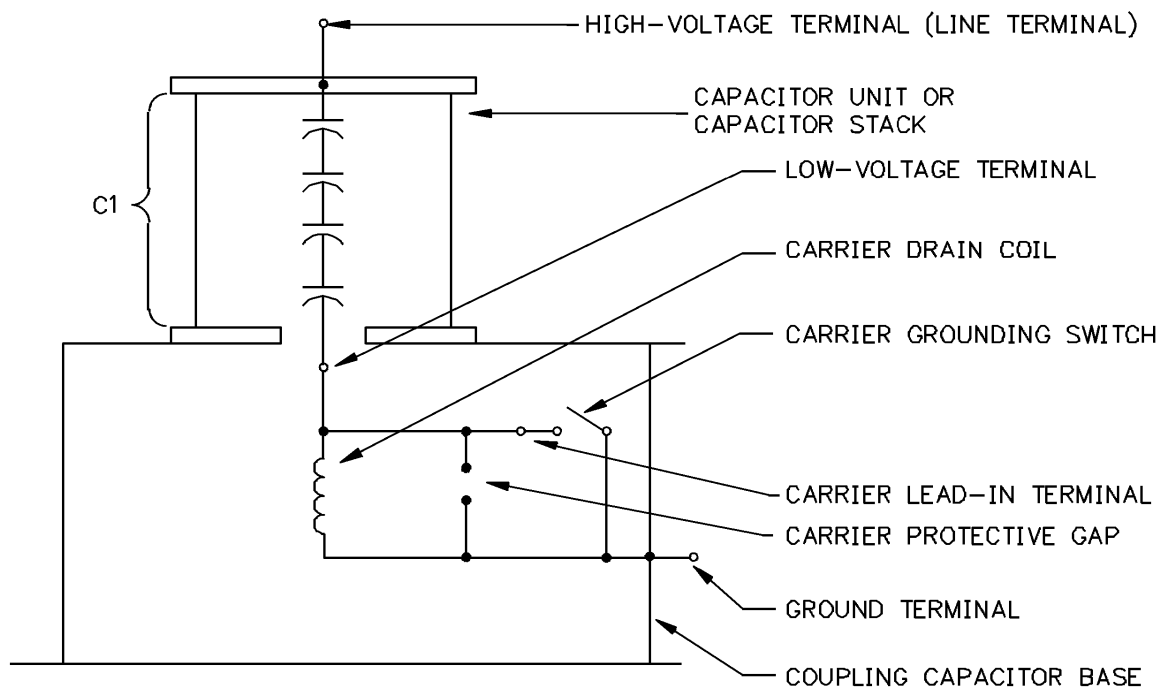
Figure 5-58: Coupling Capacitor with Carrier Accessories. Ref. ANSI Std. C93.1-1990, Figure A1.

5.11.2.1   Capacitor Stack: An assembly of one or more capacitor units. The capacitor units are enclosed in an oil-filled, sealed porcelain shell and typically mounted on a supporting base.

5.11.2.2   Base: A supporting enclosure beneath the capacitor stack that may include accessories for functional or protective purposes.

5.11.2.3   Drain Coil: An inductor connected between the low-voltage terminal and the ground terminal to provide low impedance to the 60 Hz frequency current and high impedance to the carrier frequency current.

5.11.2.4   Carrier Grounding Switch: The grounding switch is connected across the low-voltage and ground terminals and is used to bypass the drain coil during inspection or maintenance. It is operated externally by hook stick from ground elevation. It does not interrupt the operation of the high-voltage line or, when used, the voltage transformer components; however, closing the carrier grounding switch may affect the accuracy of the voltage transformer components.

5.11.2.5   Protective Gap: Spaced electrodes connected between the low-voltage and ground terminals for limiting transient overvoltages.

5.11.2.6   Lead-in Terminal: The terminal to which the coaxial cable from the power line carrier line tuning equipment is connected.

5.11.2.7   High-Voltage Terminal or Line Terminal: The terminal connected to the high-voltage power line. This terminal may also be connected on the line side of a line tram. Fusing of the high-voltage terminal is not necessary.

5.11.2.8   Low-Voltage Terminal: The terminal at the lower end of the capacitor stack located within the base.

5.11.2.9   Ground Terminal: The terminal on the exterior of the base connected directly to the ground grid.

5.11.2.10   Space Heater: A space heater may be provided in the base for prevention of condensation.

5.11.2.11   Space for Future Voltage Transformer Components: Provisions may be supplied for installing the electromagnetic unit for future conversion to a CCVT.

5.11.3   <u>Coupling Capacitor Voltage Transformers</u>

Coupling capacitor voltage transformers, commonly termed capacitor voltage transformers (CVTs), are devices used for coupling to a power line to provide low voltage(s) for the operation of relays and metering instruments. Power line carrier accessories or provisions for future installation of carrier accessories may be included in the base.

Coupling capacitor voltage transformers are commonly supplied without carrier accessories, especially at voltages above 115 kV, as a more economical alternative to inductive voltage transformers. Coupling capacitor voltage transformers can be provided with the same ratings and accuracy as inductive voltage transformers.

However, because of the energy-storage capability of capacitors, sudden reductions in the power line voltage may result in momentary distortion of the CCVT secondary voltage. The amount of distortion is related to CCVT capacitance and the burden (secondary load) value and configuration. Modern CCVT designs are available to minimize this problem.

A schematic representation of a typical CCVT with carrier coupling accessories is shown in Figure 5-59. In addition to the carrier coupling accessories described above for a coupling capacitor, a CCVT may include the following equipment and accessories.
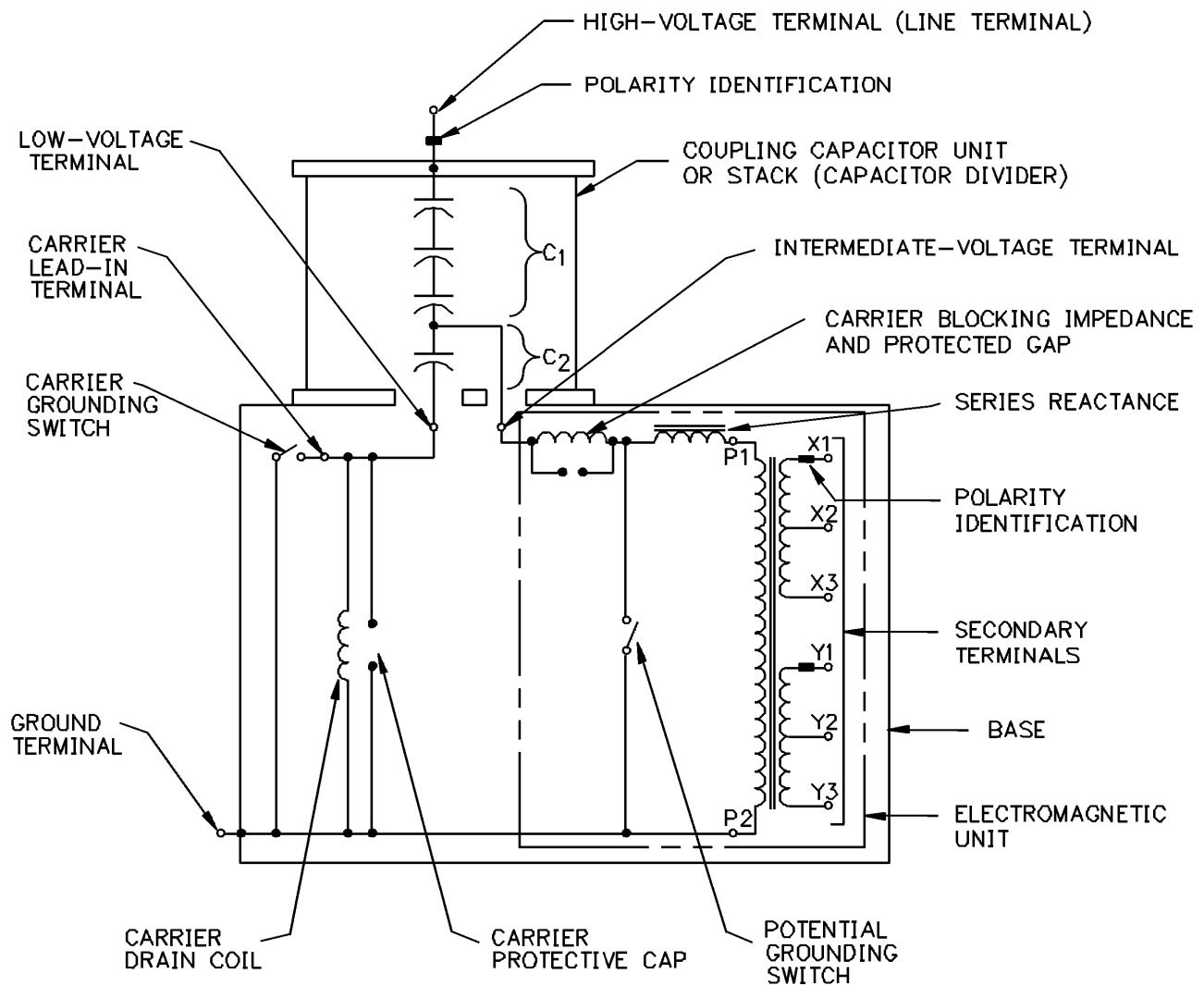
NOTE: ELECTROMAGNETIC UNIT OVERVOLTAGE PROTECTIVE GAPS AND FERRORESONANCE SUPPRESSION NETWORKS ARE NOT INCLUDED IN THIS DIAGRAM.

Figure 5-59: Typical Coupling Capacitor Voltage Transformer with Carrier Coupling Accessories.
Ref. ANSI Std. C93.1-1990, Figure A2.

5.11.3.1   Capacitor Divider: In the capacitor stack, the units are divided to form two capacitances connected in series (C_1 and C_2). The point between the two capacitances is tapped to provide a voltage proportional to the power line voltage. The tapped connection is brought to a terminal in the base designated as the intermediate-voltage terminal. The electromagnetic unit is connected between the intermediate-voltage terminal and the ground terminal.

5.11.3.2   Transformer: The transformer is the portion of the electromagnetic unit that provides a reproduction of the power line voltage at the secondary terminals of the transformer. Transformers commonly have two or more secondary windings. Each secondary winding is typically rated 120 volts line-to-neutral with a tap rated 69.3 volts line-to-neutral.

5.11.3.3   Secondary Terminals: The secondary terminals of the voltage transformer are connected for metering, protection, and control functions. The secondary circuits are typically fused although a common practice is to not fuse critical protection circuits when reliability is the key consideration. Some manufactures provide CCVTs that are designed to withstand a secondary short circuit continuously and do not require fusing; however, never intentionally short circuit the secondary of any CCVT. Also, the secondary windings of CCVTs should not be connected in a closed delta because excessive current may circulate in the delta.

5.11.3.4   Choke Coil or Blocking Impedance: The transformer is connected to the intermediate-voltage terminal through the choke coil or carrier blocking impedance. The choke coil prevents carrier frequencies from entering the electromagnetic unit. A protective gap is provided across the choke coil to limit voltage surges.

5.11.3.5   Series Reactor: A series reactor may be included in the electromagnetic unit to increase the inductive reactance of the electromagnetic unit to approximately equal the capacitive reactance of the CCVT at the power frequency.

5.11.3.6   Potential Grounding Switch: The potential grounding switch is connected between the capacitor divider intermediate-voltage terminal and the ground terminal. When closed, the potential grounding switch removes the electromagnetic unit from service. Closing the switch does not interrupt the operation of the high-voltage line or the carrier equipment. Like the carrier grounding switch, the potential grounding switch is located externally on the base and operated from elevation by hook stick.

5.11.3.7   Transformer Overvoltage Protection: Protective gaps or other means are provided to limit overvoltages in the transformer.

Older CCVTs may contain additional accessories for adjusting the voltage and capacitance of the unit. These accessories may be located in a separate cabinet mounted close to the base, usually on the same supporting structure. The accessories were required because, as the capacitors age, the voltage and capacitance values of the CCVT drift and require periodic calibration. Modern CCVT designs and materials have eliminated the need for these adjustments.

Different manufactures may use different components and arrangements to obtain secondary voltages representative of the power line voltage at the required accuracy. Manufacturers may also be able to provide specialty CCVTs for unusual applications.

Figure 5-60 shows several CCVTs installed in substations with and without wave traps. Consult with manufacturers for the options available for installation of wave traps with coupling capacitors and CCVTs.

5.11.4 Service Conditions

ANSI Std. C93.1 defines the usual service conditions for which CC and CCVT manufacturers are required to design their equipment. Consult the manufacturer when service conditions are unusual or exceed the limits stated below.

5.11.4.1 Temperature: Coupling capacitors and CCVTs are designed for outdoor service at ambient temperatures from –40°C to +45°C (–40°F to +113°F). The maximum mean temperature for a one-hour period is +45°C. Other limits are +40°C mean over 24 hours and +30°C mean over one year.

5.11.4.2 Altitude: Maximum altitude is 1000 meters (3300 feet). Dielectric strength is decreased at higher altitudes approximately 5 percent for each 500 meters above 1000 meters.

5.11.4.3 Frequencies: The power frequency is 60 Hz. The carrier frequency range is 30 to 500 kHz.

5.11.4.4 Unusual Service Condition: The service condition is considered unusual if the equipment will be exposed to damaging or explosive fumes; excessive, abrasive, or explosive dust; steam; or salt spray. Applications that require special consideration by the manufacturer include use in high-voltage power cable systems and gas-insulated substations.

5.11.5 Ratings

5.11.5.1 Voltage: The standard voltage ratings and associated insulation levels for CCs and CCVTs are provided in Table 5-79. Table 5-79 includes system voltage ratings, insulation withstand voltage levels for impulse and switching surges, power frequency withstand voltages, and minimum leakage distance of the capacitor porcelain. The right-hand columns show the standard performance reference voltage and marked ratios for CCVTs.

Table 5-79 shows that standard CCs and CCVTs are rated for line-to-ground service and possess full BILs for each nominal system voltage level. The full BIL is used partly due to standardization but also in recognition of the fact that these devices are usually located at line terminations and thus are more exposed to incoming power line surges.

Figure 5-60: Coupling Capacitor Voltage Transformers With and Without Wave Trap.
Courtesy of Haefely Trench, Scarborough, Ontario, Canada.

Table 5-79: Voltage Ratings, Dielectric Strengths, Leakage Distances, and Marked Ratios
for CCs and CCVTs.
Ref. ANSI Std. C93.1-1990, Table 3. Reproduced with permission of the
National Electrical Manufacturers Association.

Nominal System Voltage (Note 1) (kV)	Maximum System Voltage (Note 2) (kV)	Maximum Rated Volatge (Note 3) (kV)	Minimum Power-Frequency Withstand Voltage (kV) 1 Minute Dry	10 Second Wet	Minimum Basic Impulse Insulation Level (BIL) (kV)	Minimum Basic Switching Impulse Insulation Level (BSL) (kV)	Minimum Leakage Distance (inches(mm))	CCVT Performance Reference Voltage (Note 4) (Volts)	Marked Ratio (Note 4) Lower Ratio	Higher Ratio
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
34.5	36.2	21	85	72	200	--	26 (660)	20125	175:1	300:1
46	48.3	28	110	95	250	--	35 (890)	27600	240:1	400:1
69	72.5	42	165	140	350	--	48 (1220)	40250	350:1	600:1
115	121	70	265	230	550	--	79 (2010)	69000	600:1	1000:1
138	145	84	320	275	650	--	92 (2340)	80500	700:1	1200:1
161	169	98	370	325	750	--	114 (2900)	92000	800:1	1400:1
230	242	140	525	460	1050	--	154 (3910)	138000	1200:1	2000:1
345	362	209	785	680	1550	975	230 (5840)	207000	1800:1	3000:1
500	550	318	900	780	1800	1300	350 (8890)	287500	2500:1	4500:1
765	800	462	1200	1050	2425	1675	510 (12950)	431250	3750:1	6250:1

NOTES:

(1) Values from 34.5 kV through 230 kV correspond to the preferred nominal system voltages given in ANSI C84.1-1989, and values from 345 kV through 765 kV to typical "nominal" voltages given in ANSI C92.2-1987.

(2) Values from 36.2 kV through 242 kV correspond to the maximum voltage of the tolerable zone for voltages at substations and on transmission systems given in ANSI C84.1-1989, and values from 362 kV through 800 kV to the preferred maximum system voltages given in ANSI C92.2-1987.

(3) These values are phase-to-ground voltage corresponding to maximum system voltages divided by $\sqrt{3}$.

(4) For CCVTs in this table that have a double ratio achieved by means of a tap in the secondary winding(s), the nonpolarity end of the winding shall be the common terminal. Application of performance reference voltage between the high-voltage terminal and the ground terminal will result in 115 volts across the secondary windings having the lower ratio.

5.11.5.2 Thermal: The thermal burden rating of a CCVT is expressed in terms of the maximum burden a CCVT can supply at maximum voltage without exceeding the temperature limitations of the CCVT. The burden, expressed in volt-amperes, is given for each secondary winding. For CCVTs with multiple secondary windings, a total thermal burden (primary winding thermal burden) is also provided. If a single thermal rating is provided, it is applicable to any distribution of secondary volt-amperes.

5.11.5.3 Accuracy: Accuracy ratings are a means of expressing the conformity of the values obtained at the CCVT secondaries to the values calculated using the marked ratios. Accuracy classes have been established that define accuracy limits, in terms of ratio correction factor (RCF) and phase angle. The RCF is the ratio of the true ratio to the marked ratio. Standard accuracy classes include 0.3, 0.6, and 1.2 classes.

Each secondary winding is assigned an accuracy class for the standard burden for which it was designed. Burdens for accuracy rating are expressed in volt-amperes at a specified lagging power factor and given a letter designation, as shown in Table 5-80. These values are applicable at either 120 or 69.3 volts.

Table 5-80: Burdens for Accuracy Rating.
Ref. ANSI Std. C93.1-1990, Table 5. Reproduced with permission of the
National Electrical Manufacturers Association.

Burdens*			Characteristics on 120-Volt Basis			Characteristics on 69.3-Volt Basis		
Designa-tion	Volt-Amperes	Power Factor	Resistance (ohms)	Inductance (henries)	Impedance (ohms)	Resistance (ohms)	Inductance (henries)	Impedance (ohms)
M	35	0.20	82.3	1.07	411	27.4	0.356	137
W	12.5	0.10	115.2	3.04	1152	38.4	1.01	384
X	25	0.70	403.2	1.09	576	134.4	0.364	192
Y	75	0.85	163.2	0.268	192	54.4	0.0894	64
Z	200	0.85	61.2	0.101	72	20.4	0.0335	24
ZZ	400	0.85	30.6	0.0503	36	10.2	0.0168	12

* The burden designations have no significance at frequencies other than 60 Hz.

The accuracy rating of the typical CCVT will usually apply to the total burden on the device regardless of how that burden is divided among the secondary windings, provided that any burden limit on any winding is not exceeded.

CCVTs are classified for either relaying service or metering service. Metering service CCVTs has to maintain the stated accuracy for primary voltages between 90 percent of the performance reference voltage and maximum rated voltage. Metering service CCVTs shall be assigned an accuracy class of 0.3, 0.6, or 1.2 for each winding.

Relaying service CCVTs are always assigned an accuracy class of 1.2R. Relaying service CCVTs have additional requirements for maintaining accuracy limits under varying frequency conditions and low-voltage conditions.

5.11.5.4 Capacitance: CCs and CCVTs are usually classified as "high capacitance" or "extra-high capacitance," depending on the value of the high-voltage capacitance. The high-voltage capacitance C_1 is the capacitance between the high-voltage and intermediate-voltage terminals. Available ratings are listed in manufacturers' catalogs.

The typical "high-capacitance" unit can be equipped for broadband carrier coupling, and some units can be furnished for one- or two-frequency carrier coupling. High-capacitance CCVTs can be supplied with

an accuracy class of 0.3, 0.6, or 1.2. Burden capability ranges up to 200 VA. They are not suitable for revenue metering, but can be used for relaying and SCADA systems.

The typical "extra-high capacitance" device is particularly applicable on the higher voltage systems, 115 kV and above, where the increased capacitance rating is desired to provide a low impedance path for carrier signals. It is also the only type of CCVT suitable for revenue metering, when specified with an accuracy class of 0.3. Burden capability ranges up to 400 VA.

The higher capacitance devices are generally more expensive than the lower capacitance devices. However, capacitance can usually be equated to performance. In general, the higher the capacitance of the device, the better its performance characteristics will be.

The "extra-high capacitance" CCVT is particularly applicable at high-voltage and extra-high-voltage interconnections between two utilities where revenue metering from the primary transmission line is essential and where broadband coupling is desired between carrier transmitter–receiver equipment and the power line.

5.11.6   Tests

Section 6 of ANSI Std. C93.1 fully describes the various test conditions, routine tests, and design tests performed on CCs and CCVTs.

Two routine production tests that are to be made on each completed capacitor unit (i.e., an assembly of capacitor elements in a single container with accessible connections) are as follows:

5.11.6.1   Capacitance and Dissipation Factor Measurements: Capacitance and dissipation factor measurements up to rated maximum voltage and frequency before and after dielectric tests.

Dissipation factor is the tangent of the angle delta by which the phase difference between the voltage applied to the capacitor and resulting current deviates from 90 degrees. The dissipation factor is usually expressed as a percentage.

5.11.6.2   Dielectric Tests: Every capacitor is subjected to a power-frequency withstand voltage test, applied between the high-voltage and ground terminals in accordance with the values shown in Table 5-79, column 4.

Other routine tests include verification of the protective gap sparkover settings, accuracy, and polarity. For accuracy tests, ratio and phase angle measurements are made at the performance reference voltage and power frequency at the maximum burden for each rated accuracy class and at zero burden.

When testing a CCVT or during operation, never energize the CCVT from the secondary winding. The CCVT may be damaged by the voltages and currents that develop in the CCVT.

5.11.7   References

ANSI Std. C93.1, "Power Line Carrier Coupling Capacitors and Coupling Capacitor Voltage
        Transformers (CCVT) Requirements."

5.12   MOBILE UNITS

A mobile unit substation or mobile transformer is one in which all the components are mounted on a highway trailer or railcar. These units may be readily moved from one location to another by a tractor or locomotive. Mobile units are used to provide supplementary service during seasonal and temporary load conditions and as spares for existing installations during periods of outage due to equipment breakdowns or planned maintenance and construction. Their use can permit a higher quality of maintenance, more safely and at less cost, and reduce system investment in overall transformer capacity.

The actual makeup of a mobile unit will depend on factors such as the intended scope of application, degree of flexibility and reliability desired, physical size and weight restrictions, safety, and economics. Each user will have to determine the correct blend of these factors for his system.

5.12.1   Feasibility

The purchase of a mobile unit should be supported by an economic study proving this method of providing service continuity to be less expensive than other methods (such as individual spare transformers or looped feeder lines) that can provide comparable reliability of service.

The study should consider carefully the kVA capacity and voltages of the substation transformers to be spared by the mobile unit. There is a practical limit to the flexibility that should be attempted in one unit. Two (or more) units may be the best answer on some systems where the variety of substations is great.

The design of many mobile units is restricted by the opposing requirements of larger transformer capacity, higher primary voltages, and highway limitations on physical size and weight. Although it is generally desirable to obtain the maximum capacity from the transformer section of a mobile unit, it is the transformer kVA that has to be limited in most cases since, for a given mobile unit, the other components tend to remain the same in size and weight, regardless of kVA.

Since highway restrictions vary from state to state, it is difficult for a manufacturer to adopt a standard design for a mobile unit. Therefore, close coordination should be exercised among the purchaser, the design engineers, and the state highway commissions.

In attempting to meet all the requirements desired, it is important that all necessary safety clearances between phases and phase-to-ground be maintained in accordance with Chapter 4. Basic insulation levels and surge protection should be selected and coordinated in accordance with good modern practice and the specific system where the mobile unit will be used (see Section 5.2, Power Transformers, and Section 5.8, Surge Arresters).

5.12.2   Mobile Transformers

This is a transformer, usually three-phase, mounted on a trailer or semi-trailer together with cooling equipment such as an oil pump, heat exchanger, fans, etc. It is intended for application in a substation as a spare transformer in place of permanently installed transformers that may have failed or that may be undergoing maintenance. Other uses include provision of extra kVA capacity during temporary heavy load situations.

Switchgear, circuit breakers, or reclosers may or may not be included. It is recommended, however, that both high- and low-voltage surge arresters be mounted either on the transformer or on the trailer since the transformer, when in use, may be too far from the substation arresters to be protected adequately.

The availability of a mobile three-phase transformer as a spare permits a saving in the purchase of substation transformers. Instead of buying four single-phase transformers in order to have a spare in each substation, a power system can save a substantial part of this cost by buying one three-phase transformer and depending on the mobile unit for a spare. Because of the much higher cost of the mobile unit, this saving can be realized only if the system operates several substations having approximately the same kVA size and compatible voltage requirements.

5.12.3   Mobile Substations

A mobile substation may include, in addition to the transformer, air switches, surge arresters, high-voltage fuses, reclosers or breakers, voltage regulating equipment, control power and instrument transformers, meters and relays, and a control cabinet and various accessories to permit it to operate as a complete substation independent of any permanent ground-mounted equipment. Thus, it can be used not only as a spare transformer but can replace an entire substation that has been damaged or can serve as a temporary substation in a new location until a permanent substation can be built.

One limitation of a mobile substation is the number of outgoing distribution circuits that can be provided conveniently. Mobile substations can generally provide only one or two distribution circuits without an auxiliary switching structure or other supplementary equipment mounted on a separate trailer.

5.12.4   Phase Rotation Indicators

Three-phase units should be equipped with suitable phase rotation indicators or relays to ensure that power supplied to distribution circuits has the same phase rotation as that supplied from the permanent substation. Relays should also be provided to prevent reverse rotation of the fan and pump motors. Reversing switches should be added to these motors so that they can adapt to the phase rotation of the power supply.

5.12.5   Other Considerations

5.12.5.1   Impedance: To reduce size and weight, the transformers in mobile units are usually designed for forced-cooled operation with higher impedances based on the forced-cooled kVA rating than are normal for most self-cooled power transformers. These impedances sometimes are as high as 12 to 15 percent. This usually makes it impractical to continuously operate a mobile unit in parallel with a ground-mounted unit unless a sacrifice in total kVA available from the paralleled units is acceptable.

A general rule is that, for proper division of load, the impedances of transformers connected in parallel should be as close as possible and in no case differ by more than 7.5 percent. (For example, consider a transformer with a nameplate impedance of 7 percent. The allowable variation of impedance in a paralleled unit is 7.5 percent of the nameplate impedance or 0.525 percent. The paralleled transformer, therefore, should have an impedance between 6.475 percent and 7.525 percent.) If this limitation is not observed, the transformers will not divide the load proportionately, so the transformer having the lower impedance (on a common base) may be seriously overloaded. The higher characteristic impedance of mobile units on a forced-cooled base also causes a greater voltage drop under load and places a heavier duty on voltage regulating equipment.

Temporarily paralleling the mobile unit with the ground-mounted unit should be acceptable. Consideration should be given to the risk involved due to increased short-circuit levels. Equipment ratings should be checked to ensure safe operation.

5.12.5.2   Cooling System: Mobile units customarily use a forced oil–forced air cooling system that is more complex than the self-cooled system common in permanent substations.

CAUTION: Before this additional fan and pump load is placed on the substation station power system, its capacity should be carefully checked. Several features are desirable in the cooling system to reduce operating difficulties and to facilitate maintenance and repair:

5.12.5.2.1   Valves: Valves should be installed in the oil piping between the heat exchanger and the transformer tank. These allow maintenance of the forced oil cooling equipment without drawing down oil in the transformer tank.

5.12.5.2.2   Relay: A flow-type relay should be installed in the forced oil system to sound an alarm or trip the breaker if oil circulation is blocked. If oil circulation or cooling is lost, a mobile unit has no load-carrying capability and it can remain energized only for a few hours without load before excessive overheating would occur.

Fan and pump motors should have individual disconnecting switches to expedite fault location.

5.12.5.2.3   Oil Piping: The oil piping should preferably have welded joints and flange connections. Threaded connections are not recommended for mobile units because of possible loosening during transport.

5.12.5.3   Primary and Secondary Connections: Connections from mobile units to permanent substations or to overhead lines should be as short as possible. Insulated cables of the shielded type may be used where connections are quite long or exposed enough so that bare conductors may be a hazard. Cables should be equipped with suitable terminations (stress cones, potheads) at each end. Because of the expense of higher voltage (69 kV and above) cable and terminations, it is especially desirable that the primary connections be short so that bare vertical jumpers can be used safely. The ease with which connections can be made is a major factor in determining the speed with which a mobile unit may be put into service. It may be desirable to store at the substation any large pieces of equipment required to complete the installation, such as temporary wood poles, insulators, etc.

5.12.5.4   Alarm Connections: The mobile unit's alarm circuits should be temporarily connected to the substation alarm bus. Alarm indications should be considered for such items as hot oil temperature, low oil level, high combustible gas content, breaker lockout, security gate open or unlocked, and any other important indications of abnormal conditions.

5.12.5.5   Safety Considerations: A mobile unit has to always be considered as live and dangerous when in an operating position. Great care should be exercised in grounding the trailer and neutrals. Effective barriers around and under live parts should be provided wherever necessary. Interlocks should be considered to prevent energizing the unit if any required barriers are not properly in place. Additionally, a fence should be constructed around the entire mobile unit unless its operating position lies inside the substation's security fence.

Because of the different application of mobile units as compared to regular substation components, it is often acceptable to consider the mobile unit as a tool that is to some extent expendable. This approach will permit reasonable deviation from strict application of many major, basic electrical properties.

Reduced insulation levels, higher temperature ratings, higher impedance, more extreme overloading (into the loss-of-life range), and reduced clearances can all be considered as possible tradeoffs to obtain more transformer kVA capacity and voltage selection flexibility. Other optimal application considerations may be found through discussions with suppliers of mobile units. As mentioned earlier, minimum safety requirements should not be sacrificed to obtain other advantages.

5.12.5.6   Protection: In designing the protection for a mobile unit, consideration should be given to two factors that distinguish it from the normal substation situation:

1. A mobile unit is much more expensive.
2. The temporary nature and perhaps hurried installation may increase the probability of a fault.

Both factors may dictate a better than normal protection scheme.

5.12.5.7   Installation Requirements of Mobile Units: Chapter 4, Physical Layout, discusses many of the considerations for installation of mobile units at the substation.

5.12.6   Accessories Included with the Mobile Unit

All accessories necessary for proper operation of the mobile unit should be placed at convenient locations on the trailer. Accessories that are readily available at the locations where the unit is expected to be used may be omitted. Determining which accessories to mount on board will require a careful study of all sites as well as space availability on the trailer.

Types of accessories to be considered include power cable and connectors, grounding cables and connectors, power supply transformers, control batteries, heaters, lights, plug outlets, spare fuses, fencing, and special equipment or tools for mobile unit components and the trailer.

CHAPTER 6
SITE DESIGN

6.1 GENERAL

The objective of site work design for a substation yard is to provide an easily accessible, dry, maintenance-free area for the installation and operation of electrical substation equipment and structures. Factors related to the actual location of the substation site are covered in Chapter 2.

The engineer should make a personal site inspection before the design is started. The engineer should take advantage of the natural drainage and topographical features in the design consistent with the electrical layout since coordination of the two is essential.

6.2 TYPES OF GRADED YARDS

There are generally three basic profiles for substation yards:

1. Flat—most prevalent (Figure 6-1)
2. Sloped—occasionally required (Figure 6-2)
3. Stepped—seldom required (Figure 6-3)
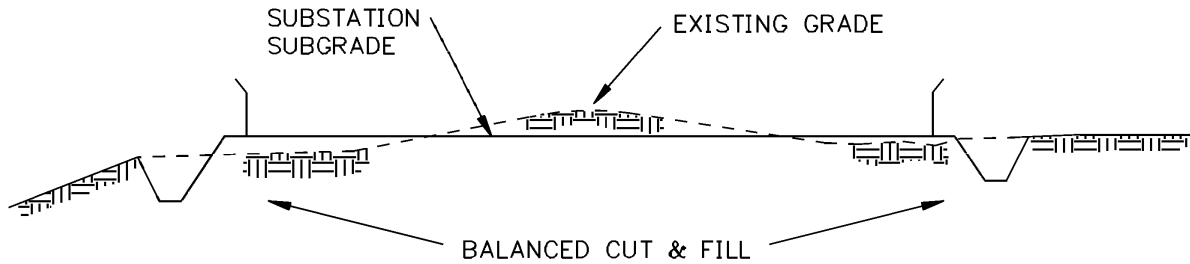
Figure 6-1: Flat Yard
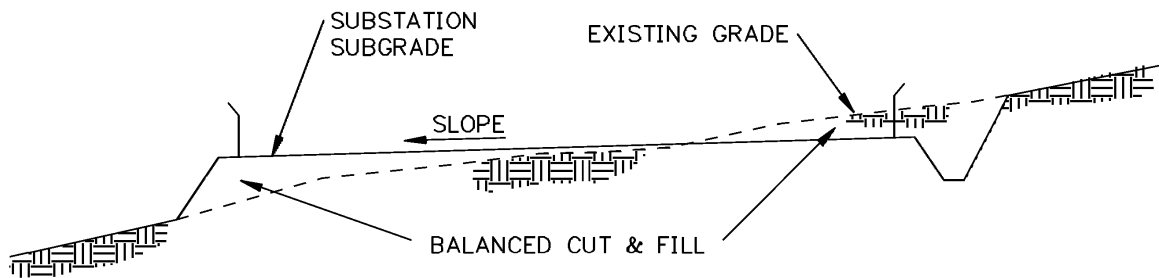
Figure 6-2: Sloped Yard on Moderately Sloped Site
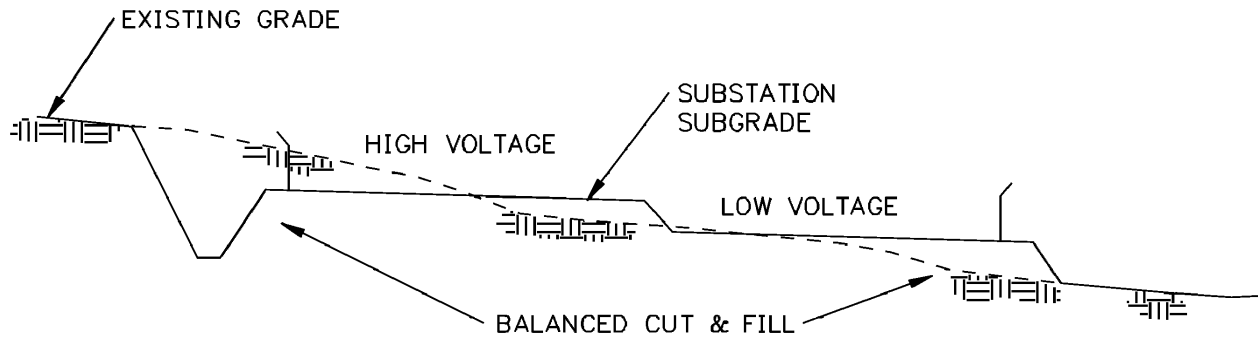
Figure 6-3: Stepped Yard

6.2.1 Flat Yards

The basic flat yard is more desirable for the layout and operational function of a substation. It permits uniformity in foundation elevations and structure heights. Unless there are property restrictions, severe topographical features, subterranean rock, or other considerations dictate otherwise, the yard should be graded nominally flat. (See Section 6.4, Drainage Considerations.)

6.2.2 Sloped Yards

Occasionally, property restrictions or economic considerations will outweigh the desirability for a flat yard, and a continuously sloping yard may be advantageous.

6.2.3 Stepped Yards (Two or More Levels)

Stepped yards are usually created by extreme property restrictions, adverse mountainous terrain, or underlying rock formations making excavation uneconomical.

Modification of any of the three types may be necessary to arrive at the optimum yard design. Sloped and stepped sites entail extra design considerations and close coordination with the electrical layout. There may be more structures required and variable foundation elevations.

6.3 PRELIMINARY REQUIREMENTS

The following lists some of the basic information required for the site preparation design for a substation yard:

    a.   Area maps (aerial photos if available)
    b.   Topographic drawing of immediate area showing:

        1.   Ground elevations on a grid system at 15m (50-foot) spacing
        2.   Location and elevation of existing roads, railroads, ditch inverts, and culverts
        3.   Location of pertinent overhead or underground utilities, particularly the exact location and depth of any pipelines

4. Property plan (legal description of property)
5. Location of the area's drainage exits
6. High water elevation in area, if any
7. Flood zone designation with base flood elevation, if any

c. Soil borings in immediate site area

6.4 DRAINAGE CONSIDERATIONS

6.4.1 Stormwater Management

Review state and local government regulations for stormwater management requirements. Many local governments have adopted storm drainage criteria and require that stormwater detention or retention basins be provided, and a few require zero discharge from the site.

6.4.2 Surface Drainage System

Generally all three profiles lend themselves to a surface runoff system. Such a system consists of a gently sloping (0.5 percent to 0.75 percent) ground surface so that the water drains to the edge of the yard or to shallow ditches within the yard. The ditches may discharge into culverts or shallow open channels removing the runoff from the yard.

6.4.3 Closed Drainage System

A closed drainage system is a network of catch basins and storm sewer pipe that provides a more positive means of yard drainage. This type of system is quite costly. Circumstances other than economics, however, may require the use of this system. Rural substations will rarely require a closed drainage system.

6.4.4 Planning

The yard surface drainage has to be coordinated with the location of cable trenches and roads within the yard. The yard profile (flat, sloped, or stepped) may present varying drainage design considerations. Careful review of the quantity, quality, and particularly the location of the discharge water from the yard is emphasized. Planning the initial drainage system for a future substation addition is sometimes required. Generally a good rule to follow is do not discharge any more water into an existing drainage area outlet than what originally occurred. Small interceptor ditches strategically located will prevent erosion of slopes or embankments.

6.4.5 Design

Whenever it is necessary to calculate the amount of rainfall runoff for the design of culverts, storm sewer pipes, detention or retention ponds, or ditches, a widely used and accepted method is the "Rational Method." The Rational Method is not recommended for drainage areas much larger than 100 to 200 acres.

The Rational Method formula is expressed by Equation 6-1:

Equation 6-1
Q = CiA

Where:

A = Drainage area in m^2 (acres)

i = Average rainfall intensity m/hr (in/hr) for the period of maximum rainfall of a storm of a given frequency of occurrence, having a duration equal to the "time of concentration (tc)"

tc = Time required for runoff from remotest part of drainage area to reach the point under design

C = Runoff coefficient

Q = Quantity m^3 /hr (cfs) (NOTE: Metric units have to be converted to m^3/s for the Chezy-Manning Formula.)

Table 6-1 and Figures 6-4 and 6-5 provide information to assist in determining the rainfall intensity for different geographical areas, durations, and recurrence intervals. Additional information concerning rainfall and frequency is available from U.S. Weather Bureau Offices and other technical and hydrological publications. Tables showing runoff coefficients for various types of terrain and gradient are available in texts on this subject.

Table 6-1: Rainfall Intensity and Conversion Factors

DURATION IN MINUTES	FACTOR	DURATION IN MINUTES	FACTOR
5	2.22	40	0.8
10	1.71	50	0.7
15	1.44	60	0.6
20	1.25	90	0.5
30	1.00	120	0.4

RAINFALL INTENSITY CONVERSION FACTORS

RECURRENCE INTERVAL IN YEARS	FACTOR
2	1.0
5	1.3
10	1.6
25	1.9
50	2.2

RECURRENCE INTERVAL FACTORS

Frequency of storm occurrence should be 2 or 5 years, and the time of concentration should be between 15 and 20 minutes for a reasonable and economical design. The design example illustrates a sample problem.

6.4.5.1 Design Example

Design a culvert in a substation in Lansing, Michigan, given the following information:

1. Drainage area = 2000 m^2
2. Time of concentration = 15 minutes
3. Period of recurrence = 5 years
4. Coefficient of runoff = 0.50
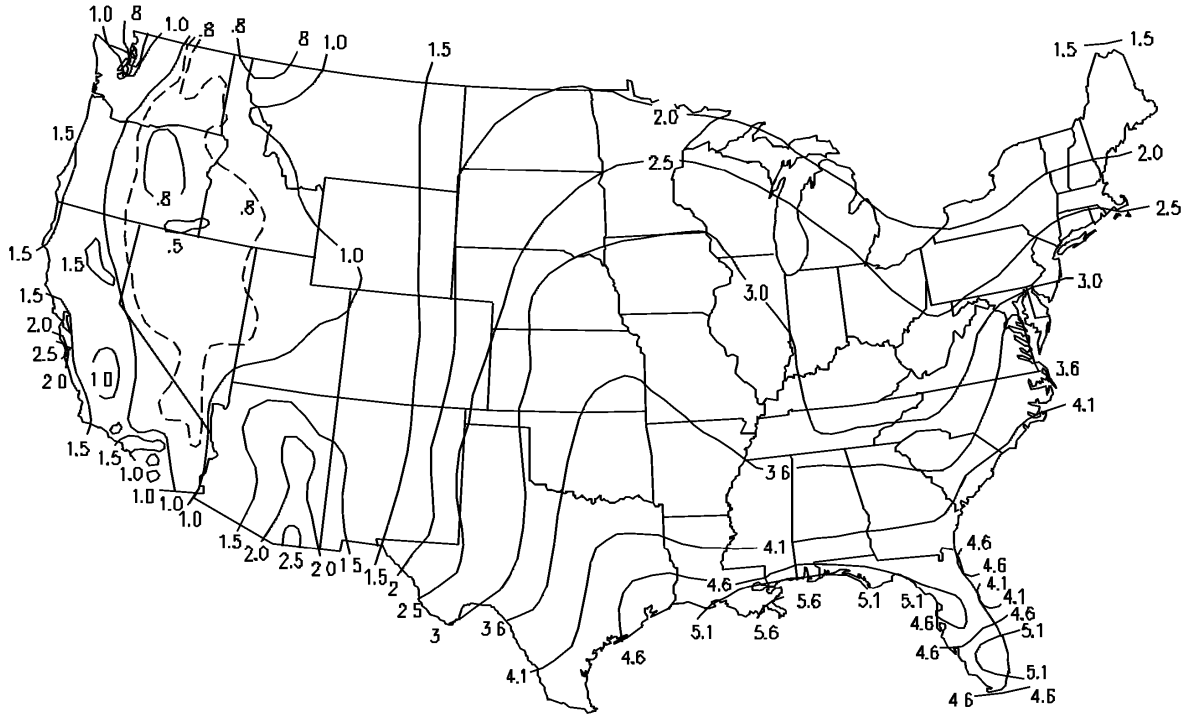
Figure 6-4: 2 Year 30-Minute Rainfall Intensity (cm/hr).
Adapted from Chart 2, *Rainfall Frequency Atlas of the United States*,
U.S. Department of Commerce, Weather Bureau, Technical Paper 40, May 1961.
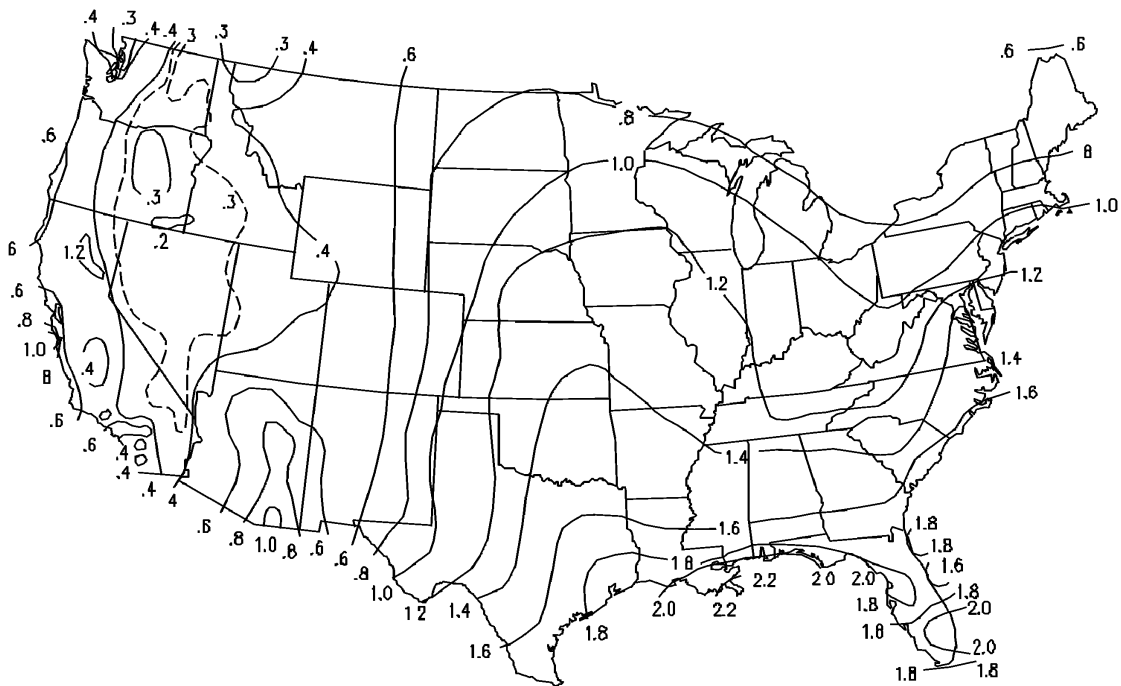
Figure 6-5: 2 Year 30-Minute Rainfall Intensity (inches/hr).
Rainfall Frequency Atlas of the United States,
U.S. Department of Commerce, Weather Bureau, Technical Paper 40, Chart 2, May 1961.

From Table 6-1 and Figures 6-4 and 6-5 determine i for a 5-year storm of 15 minutes' duration as follows:

	(2-yr., 30-min. duration)		(15-min. duration factor)		(5-yr. recurrence factor)
i =	0.05m/hr	x	1.44	x	1.3

$$= 0.094 \text{ m/hr}$$

The culvert then has to convey:

$$Q = 0.50 \text{ x } 0.094 \text{ m/hr x } 2000 \text{ m}^2 = 94 \text{ m}^3/\text{hr} \quad \text{or}$$
$$Q = 94 \text{ m}^3/\text{hr x } 1 \text{ hr}/3600 \text{ sec} = 0.026 \text{ m}^3/\text{sec}$$

Assuming that 0.20m ϕ, corrugated, metal pipe will handle the flow, and using the Chezy-Manning Formula, determine the slope of the pipe as follows:

$$0.026 \; m^3/\sec = 0.032 \; m^2 \; x \; \frac{1}{0.024} \; x \; 0.05 \; m^{2/3} \; x \; s^{1/2}$$

$$S = 0.021 \text{ m/m}$$

$$v = \frac{0.026 \; m^3/\sec}{0.032 \; m^2} = 0.81 \; \text{m/sec}$$

The velocity at the minimum slope to handle the discharge volume is not quite self-cleaning, but would probably be okay.

Once the quantity of water is determined by the Rational Method, the actual size of storm sewer pipe, culverts, or ditches may be determined using the Chezy-Manning Formula:

Equation 6-2

$$Q = AV = A \; x \; \frac{1.0}{n} \; x \; R^2 3 \; x \; S^1 2 \text{ (metric)}$$

Equation 6-3

$$Q = AV = A \; x \; \frac{1.486}{n} \; x \; R^2 3 \; x \; S^1 2 \text{ (English)}$$

Where:
   Q = Volume of pipe or ditch discharge m³/s (cfs)
   A = Cross-sectional area of pipe or ditch flow m² (ft²)
   V = Velocity = m/s   (ft/s)
   n = Roughness coefficient for pipe or ditch
   R = Hydraulic radius of pipe or ditch m (ft)

$$(\frac{\text{Area of Section}}{\text{Wetted Perimeter}}) = \frac{D}{4} \text{ for pipe}$$

   S = Hydraulic gradient m/m   (ft/ft)   (slope of pipe or ditch)

After the size of pipe or ditch is determined, both minimum and maximum flow velocities should be reviewed. For pipes to be "self-cleaning" a minimum velocity of one m/s (3 ft/s) is required to prevent silting. Water in ditches, however, should be allowed to flow approximately 0.5m/s (1 or 2 ft/s) in unprotected ditches and up to a maximum of about l.5m/s (5 ft/s) in sodded channels before erosion occurs. Special erosion protection at open discharge ends of storm sewers and both ends of culverts should be made. Flared end sections and riprap or concrete headwalls should be specified to protect these areas from scour and erosion.

6.5   EARTHWORK CONSIDERATIONS AND DESIGN

The computation of earthwork quantities is usually the first step in establishing the nominal rough grade elevation of the yard.

Clearing and grubbing of the site is required, and all vegetation should be removed and properly disposed of. Generally, the topsoil in the substation area is removed and stockpiled for future use in areas requiring seeding.

CAUTION: When there may be a question of determining what consists of topsoil material, the engineer should define the limits of topsoil stripping as specifically as possible.

6.5.1   Borrow

When the natural grade of the proposed site is essentially flat, it may be necessary to bring in fill material (borrow) to improve the drainage condition of the yard. However, the engineer should avoid the use of borrow in the site design if possible.

The borrow material should consist of a satisfactory soil free from sod, stumps, roots, large rocks, or other perishable or deleterious matter. It should be capable of forming a stable embankment when compacted in accordance with the requirements of this section. Acceptable soils for borrow as identified by the Unified Soil Classification System are GW, GP, GM, GC, SW, SP, SM, and SC (see Table 6-2).

The borrow pit should be located on the property if possible. If the borrow pit is located a remote distance from the site, the engineer should reevaluate the site design to avoid hauling borrow long distances.

6.5.2   Topsoil

Removing topsoil on flat natural sites increases the borrow or fill requirements. Conditions when it would be excessively uneconomical to remove all the topsoil might be:

    a.   Excessive depth of topsoil - 0.5 m (18") and deeper
    b.   When borrow material has to be hauled long distances

The engineer should evaluate alternatives to stripping the topsoil in such circumstances.

One alternative when conditions do not seem favorable for removing topsoil is to uniformly mix the topsoil with the underlying soil. The mixture is very often suitable for embankments up to 1 meter (3 feet).

Table 6-2: Unified (ASTM) Soil Classification System. Ref. ASTM Std. D-2487, Table, Soil Classification Chart, Figure 3, Plasticity Chart. Copyright © ASTM. Reprinted with permission.

MAJOR DIVISIONS			GROUP SYMBOLS	TYPICAL NAMES	CLASSIFICATION CRITERIA			
COARSE-GRAINED SOILS MORE THAN 50% RETAINED ON NO. 200 SIEVE*	GRAVELS 50% OR MORE OF COARSE FRACTION RETAINED ON NO. 4 SIEVE	CLEAN GRAVELS	GW	WELL-GRADED GRAVELS AND GRAVEL-SAND MIXTURES, LITTLE OR NO FINES	CLASSIFICATIONS ON BASIS OF PERCENTAGE OF FINES	LESS THAN 5% PASS NO. 200 SIEVE: GW, GP,SW, SP / MORE THAN 12% PASS NO. 200 SIEVE GM, GC, SM, SC / 5% TO 12% PASS NO. 200 SIEVE BORDERLINE CLASSIF-ICATION REQUIRING USE OF DUAL SYMBOLS	$C_u=D_{60}/D_{10}$ GREATER THAN 4 / $C_z=\dfrac{(D_{30})^2}{D_{10} \times D_{60}}$ BETWEEN 1 AND 3	
			GP	POORLY GRADED GRAVELS AND GRAVEL-SAND MIXTURES, LITTLE OR NO FINES			NOT MEETING BOTH CRITERIA FOR GW	
		GRAVELS WITH FINES	GM	SILTY GRAVEL, GRAVEL-SAND-SILT MIXTURES			ATTERBERG LIMITS PLOT BELOW "A" LINE OR PLASTICITY INDEX LESS THAN 4	ATTERBERG LIMITS PLOTTING IN HATCHED AREA ARE BORDERLINE CLASSIFICATIONS REQUIRING USE OF DUAL SYMBOLS
			GC	CLAYEY GRAVELS, GRAVEL-SAND-CLAY MIXTURES			ATTERBERG LIMITS PLOT ABOVE "A" LINE AND PLASTICITY INDEX GREATER THAN 7	
	SANDS MORE THAN 50% OF COARSE FRACTION PASSES NO. 4 SIEVE	CLEAN SANDS	SW	WELL-GRADED SANDS AND GRAVELLY SANDS, LITTLE OR NO FINES			$C_u=D_{60}/D_{10}$ GREATER THAN 6 / $C_z=\dfrac{(D_{30})^2}{D_{10} \times D_{60}}$ BETWEEN 1 AND 3	
			SP	POORLY GRADED SANDS AND GRAVELLY SANDS, LITTLE OR NO FINES			NOT MEETING BOTH CRITERIA FOR SW	
		SANDS WITH FINES	SM	SILTY SANDS, SAND-SILT MIXTURES			ATTERBERG LIMITS PLOT BELOW "A" LINE OR PLASTICITY INDEX LESS THAN 4	ATTERBERG LIMITS PLOTTING IN HATCHED AREA ARE BORDERLINE CLASSIFICATIONS REQUIRING USE OF DUAL SYMBOLS
			SC	CLAYEY SANDS, SAND-CLAY MIXTURES			ATTERBERG LIMITS PLOT ABOVE "A" LINE AND PLASTICITY INDEX GREATER THAN 7	
FINE-GRAINED SOILS 50% OR MORE PASSES NO. 200 SIEVE*	SILTS AND CLAYS LIQUID LIMIT 50% OR LESS		ML	INORGANIC SILTS, VERY FINE SANDS, ROCK FLOUR, SILTY OR CLAYEY FINE SANDS				
			CL	INORGANIC CLAYS OF LOW TO MEDIUM PLASTICITY, GRAVELLY CLAYS, SANDY CLAYS, SILTY CLAYS, LEAN CLAYS				
			OL	ORGANIC SILTS AND ORGANIC SILTY CLAYS OF LOW PLASTICITY				
	SILTS AND CLAYS LIQUID LIMIT GREATER THAN 50%		MH	INORGANIC SILTS, MICACEOUS OR DIATOMACEOUS FINE SANDS OR SILTS, ELASTIC SILTS				
			CH	INORGANIC CLAYS OF HIGH PLASTICITY, FAT CLAYS				
			OH	ORGANIC CLAYS OF MEDIUM TO HIGH PLASTICITY				
HIGHLY ORGANIC SOILS			PT	PEAT, MUCK, AND OTHER HIGHLY ORGANIC SOILS	VISUAL-MANUAL IDENTIFICATION, SEE ASTM DESIGNATION D 2488.			

PLASTICITY CHART
FOR CLASSIFICATION OF FINE-GRAINED SOILS AND FINE FRACTION OF COARSE-GRAINED SOILS
ATTERBERG LIMITS PLOTTING IN HATCHED AREA ARE BORDERLINE CLASSIFICATIONS REQUIRING USE OF DUAL SYMBOLS
EQUATION OF A LINE
$PI=0.73\,(LL-20)$

The mixture may also be compacted in place and serve as a non-bearing base upon which to build the embankment. The engineer should make certain that the soil to be mixed with the topsoil is predominantly granular soil. Silts or clays would not be suitable. The mixture should consist of one or more parts of good soil to one part of topsoil.

When alternatives to topsoil removal are considered, the foundation design should take into account the depth at which the soil conditions have been altered.

6.5.3 Cut and Fill

On other than flat natural grade conditions, the nominal elevation of the yard is usually determined from a balance between the required earth "fill" for the embankment and the available earth that has to be excavated or "cut" from the higher areas of the site. All cut-and-fill slopes should be one vertical to four horizontal if possible.

There are several software programs available with which the engineer can input digitized topography and roadway templates and the programs will output earthwork quantities.

The computer software programs contain a digital terrain model (DTM), which is a graphical representation of the topography of the site. The DTM is created from using a triangulated irregular network (TIN) model of points from the site survey. Changing the surface terrain is simulated by building new surfaces to create the final grade and merging them with the existing terrain into the revised site representation. The software program then compares the two surfaces to compute the earthwork volumes.

Cut and fill quantities can also be computed by the "average end area method," which is explained in most surveying books. Briefly, the method consists of drawing cross sections taken every 15 meters (50 feet) or 30 meters (100 feet). The areas of cut and fill are determined from the computed sections with a planimeter. The sections are usually drawn with a vertical scale exaggeration of ten times the horizontal scale. The sections show both the existing profile and the proposed profile.

To compute the earthwork, the "cut" and "fill" areas of each section are totaled separately and added to the "cut" and "fill" quantities of the adjacent section.

The average of the cut summation and the average of the fill summation for each pair of adjacent sections are multiplied by the distance between sections to obtain the volumes of cut and fill. This procedure is followed at each section plotted across the substation yard.

Usually several adjustments to the proposed elevation are necessary to balance the earthwork. Only 80 to 85 percent of cut volume, as previously computed, is assumed to be available for fill. The 15 to 20 percent reduction allows for losses due to compaction, spillage, and unsuitable material.

6.5.4 Compaction

Adequate compaction during placement of the fill is necessary to develop the required soil bearing capacity and lateral resistance for the foundation design. It is necessary also to prevent settlement due to consolidation of the embankment, which may result in ponding, broken ducts, conduits, cable trenches, etc. All fill areas should be compacted in 200 mm (8-inch) layers to 95 percent of the maximum density obtained by AASHTO Std. T180. The base upon which the embankment is constructed should also be loosened and compacted.

6.5.5 Cleanup

Upon completion of the site work, all excavated earth not used in backfilling should be leveled off or shaped to present a neat appearance and not obstruct any drainage. Borrow pits should be graded to a smoothly contoured shape. It may be necessary to provide seeding mulching to such areas.

6.6 ROADS AND OTHER ACCESS

6.6.1 General Access Roads

Access roads into substation yards have to be adequate to sustain heavy equipment under all weather conditions. Long access roads require design considerations similar to most secondary county or state roads. Any culverts or sewer crossings also need to be designed for anticipated heavy equipment loads.

6.6.2 Grade

The maximum grade on the access road should generally not exceed 7 percent so that heavy transformers may be transported to and from the yard by normal movers without problems. Ten percent grades may be tolerated for short distances of 60 to l00 meters (200 to 300 feet).

6.6.3 Curvature

The inside radius of the access road at 90 degree intersections with major roads should not be less than 15 meters (50 feet) in order to provide sufficient turning space for long vehicles. Smaller radii may be adequate for substations below 230 kV.

6.6.4 Design

Where space allows, access roads should be about 6 meters (20 feet) wide. The road should be crowned at the center for drainage.

The subgrade for the road should be prepared and compacted to the same requirements as the embankment for the yard.

The wearing course for access roads in substations up to 69 kV may consist of a 200 mm (8-inch) deep aggregate base course. State highway department standard specifications usually contain several different types of base course material.

For larger substations, the access road may consist of a 200 mm (8-inch) aggregate base course and a 100 mm (4-inch) aggregate surface course. Highway standard specifications include several types and specify the related material and gradation requirements for the base and surface course material.

Application of the wearing courses should be made in accordance with highway standard specifications.

6.6.5 Railroad Spur

Railroad spurs may be economically feasible at some substation locations. Coordination with the responsible railroad company will usually determine the requirements for making the turnout. Often the railroad company will insist on installing the track for a specified length from the main line. Normally,

the railroad company's standards are specified in regard to ballast, ties, rails, and connections. The compaction requirements used for the yard embankment are adequate for the spur track subgrade.

6.6.6 Roadways in the Substation Yard

Many substations do not have any specific drives or roads within the fenced yard. The entire yard is considered as driveable by light traffic.

If it is desirable to have specific drives within the fenced yard for access to transformer banks or as a perimeter drive, the wearing surface can be the same as for the access road. The width may be reduced to 5 meters (16 feet) or even less. Inside radii for interior drives may be 7.5 meters (25 feet) or less as space allows. Culverts and cable trenches should also be designed for anticipated heavy equipment loads.

6.7 EROSION PROTECTION

6.7.1 General

All cut and fill slopes, ditches, and all other areas outside the fenced yard from which topsoil or vegetation was removed should be protected from wind and water erosion.

In most cases the placement of topsoil, fertilizer, mulch, and seed are sufficient and economical for erosion protection. Topsoil should be placed about 100 mm (4 inches) thick. Consult the local agricultural extension office or the highway department for appropriate types and application rates of fertilizer and seed.

Slopes greater than 1 vertical to 2 ½ horizontal may require sodding. The engineer should attempt to keep slopes at 1 vertical to 4 horizontal for erosion and maintenance purposes.

Riprap should be used at corners and intersections of ditches where erosion is likely.

6.7.2 Legal Requirements

Because of the large amount of land under construction each year, erosion and sedimentation control during construction have become a problem. Many states and localities now have laws or ordinances to control soil erosion on construction sites and the sedimentation of adjoining waterways.

The engineer should become aware of such state laws, which are usually enforced by the counties. Many counties have extensive guidelines that have to be strictly adhered to. Consult county agricultural extension offices for these requirements.

The soil erosion and sedimentation control statutes may mean considerably more engineering time to develop drawings to show compliance with the requirements of the statute.

6.8 YARD SURFACING MATERIAL

It is desirable to have 100 to 150 mm (4 to 6 inches) of crushed stone or rock cover the entire substation yard and to extend 1 meter (3 feet) beyond the substation fence. In some locations clam and oyster shell may also be used. The yard surface material helps reduce the danger of potentially hazardous mesh and

touch potentials; minimizes weed growth; provides a clean, reasonably dry walking surface during wet periods; dissipates erosion effect from rain; and contributes to better access drives for light vehicles.

In cases where a more substantial and unlimited drive area is desirable, a 100 mm (4-inch) layer of well-graded gravel (highway aggregate base course material) is placed and rolled firm. A 75 mm (3-inch) layer of crushed stone or rock may then be placed on top. In areas where clam and oyster shell is available, a very durable drive surface is easily obtained.

The size of stone for yard surfacing material should generally vary between 10 mm and 25 mm (3/8 to 1 inch) with the percentage finer than 10 mm (3/8 inch) limited to 5 to 10 percent. Usually the state highway department has gradations in this range. All faces of yard surface material should be crushed. Use of round rock (river rock) is to be avoided due to rutting problems.

The material selected for yard surfacing may be affected by the electrical grounding design (see Chapter 9, Grounding, for details). Because of electrical fault currents, surfacing material may need to be specified differently than would otherwise be the case. It may be desirable to have a 100 to 150 mm (4- to 6-inch) layer of crushed rock as coarse as can reasonably be walked on with as few fines as practical or nominally available.

Before the yard surfacing material is installed, the yard surface should be brought to its proposed elevations and rolled to a reasonably firm condition. A soil sterilizer may be applied to prevent the growth of grass and weeds at this time. The yard stone or shell should then be spread as evenly as practical but need not be rolled. This work should not begin until all substation work is essentially completed.

6.9 SECURITY FENCE

Generally, all outdoor substations are enclosed by a security fence, as discussed in Chapter 2. Safety clearance requirements for substation fences are covered in Chapter 4.

The fence should be installed as soon as practicable after the site work is completed. This work is usually done by a fence contractor and is not necessarily a part of the general contract.

A typical specification for material and installation of a chain-link security fence is found in the Appendix C to this chapter. Bear in mind that numerous other rail, post, and gate frame component designs will serve at least equally as well as those noted in the typical specification.

6.10 REFERENCES

AASHTO Std. T180, "Standard Method of Test for Moisture-Density Relations of Soils Using a 10-lb Rammer and an 18-inch Drop."

American Iron and Steel Institute, *Handbook of Steel Drainage and Highway Construction Products*, 2d ed., American Iron and Steel Institute, 1971.

ANSI/IEEE Std. C2, *National Electrical Safety Code.*

ASTM A36, "Specification for Carbon Structure Steel."

ASTM A53, "Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless."

ASTM A121, "Specification for Zinc-Coated (Galvanized) Steel Barbed Wire."

ASTM A123, "Specification for Zinc (Hot Dip Galvanized) Coating on Iron and Steel Products."

ASTM A153, "Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware."

ASTM A392, "Specification for Zinc-Coated Steel Chain-Link Fence Fabric."

ASTM A500, "Specification for Cold-Formed Welded and Seamless Carbon Steel Structural Tubing in Rounds and Shapes."

ASTM A501, "Specification for Hot-Formed Welded and Seamless Carbon Steel Structural Tubing."

ASTM D2-487, "Unified (ASTM) Soil Classification System."

ASTM F1043, "Standard Specification for Strength and Protective Coatings on Metal Industrial Chain Link Fence."

Portland Cement Association, *PCA Soil Primer.*

U.S. Department of Agriculture, Soil Conservation Service, "Controlling Erosion on Construction Sites," Agriculture Bulletin 347.

APPENDIX C

SAMPLE SUBSTATION SECURITY FENCE SPECIFICATION

S.6.1 GENERAL

This Specification covers the requirements and general recommendations for material and erection of security fencing for substations.

> This is a sample specification. Cooperatives should verify compliance with local standards and check availability of materials from local suppliers when writing their specifications.

The substation fence shall consist of woven steel fabric on steel posts plus barbed wire on extension arms. It shall be a minimum of 2134 mm (7 feet) high with line posts no greater than 3048 mm (10 feet) apart. (RUS recommends 8 feet for the fence height: 7 feet of fabric and a 1-foot extension of barbed wire.) More specific requirements are further described under the Material and Erection sections of this Specification.

The primary components of the fence are:

1. Fabric
2. Line posts
3. End and corner posts
4. Gate posts
5. Top rail
6. Barbed wire
7. Extension arms
8. Stretcher bars
9. Post braces
10. Tension wire
11. Gate frames
12. Hardware (hinges, latches, stops, keepers, ties, clips, bands)

> NOTE: This sample specification calls for a combination of woven steel fabric and strands of barbed wire. NESC C2-1997 allows for a 2134 mm (7-foot) woven steel fabric barrier.

S.6.2 MATERIAL

S.6.2.1 Fabric

The fence fabric shall be a minimum of 1830 mm (6 feet) high. (RUS recommends 7 feet of fence fabric.) It shall consist of a minimum No. 9 USWG steel wire, woven into a 51 mm (2-inch) square mesh. The minimum breaking strength of wire shall be 5338 N (1200 lbs). The sides of the mesh pattern shall be approximately 45 degrees to a vertical line.

The fabric shall be galvanized in accordance with ASTM A392, Class 2.

S.6.2.2 Line, End, Corner, Pull, and Gate Posts

All posts shall be steel and conform to the sizes as listed in Table 6-3 for the specific type of application. Strength and protective coatings of all fence framework shall conform to ASTM F1043.

Table 6-3: Fence Posts for 2134 mm (7-Foot) Fence

Use	Type	Minimum Size
Line Posts	Round	Metric: 60 mm OD; t = 4 mm English: 2-3/8 in. OD; t = 0.154 in.
	Square	Metric: 50 mm sq; t = 4.25 mm English: 2 in. sq; t = 0.1875 in.
	Rolled or Formed Section	Size so that bending strength about strong axis is not less than that of the round post.
End, Corner, Pull Posts	Round	Metric: 73 mm OD; t = 5 mm English: 2-7/8 in. OD; t = 0.203 in.
	Square	Metric: 63 mm sq; t = 4.75 mm English: 2-1/2 in. sq; t = 0.1875 in.
	Rolled or Formed Section	Size so that bending strength about weak axis is not less than that of the round post.
Gate Posts	Round	Metric: 100 mm OD; t = 5.75 mm English: 4 in. OD; t = 0.226 in.
	Square	Metric: 76 mm sq; t = 6 mm English: 3 in. sq; t = 0.25 in.
	Rolled or Formed Section	Size so that bending strength about weak axis is not less than that of the round post.

Tubular material should conform to ASTM A53 Grade B for round shapes and ASTM A500 Grade B or ASTM A50l for square shapes. Roll-formed sections shall meet the yield stress requirements of ASTM A36 as a minimum.

Line posts and gate posts shall be of sufficient height to (a) accommodate 1830 mm (6-foot) fabric; (b) accommodate extension arms or extend 305 mm (1 foot) extra, and (c) be embedded 914 mm (3 feet) into the concrete footing.

End, corner, and pull posts shall be of sufficient height to (a) accommodate 1830 mm (6-foot) fabric; (b) accommodate extension arms or extend 305 mm (1 foot) extra, and (c) be embedded 914 mm (3 feet) into the concrete footing.

All tubular posts shall be galvanized in accordance with ASTM A53. Roll-formed sections shall be galvanized in accordance with ASTM A123.

S.6.2.3 Top Rail

Top rails shall be round steel pipe or tubing. The minimum size shall not be less than 41 mm (1 5/8 inches) O.D. nor have a minimum wall thickness less than 4 mm (0.138 inch). Lengths should be a minimum of 5 meters (16 feet). Provisions for adequately joining lengths together and securing to end or corner posts shall be compatible for the physical size of the top rail. Top rails shall be galvanized in accordance with ASTM A53.

S.6.2.4 Barbed Wire

Barbed wire shall consist of two strands of 12-1/2 USWG steel wire with 4-point barbs at a maximum

spacing of 127 mm (5 inches) apart. The wire shall be galvanized after weaving in accordance with ASTM A121, Class 3.

S.6.2.5 Extension Arms

The extension arms shall extend upward and outward from the fence at an angle of 45 degrees. There shall be provisions for three equally spaced lines of barbed wire on the extended arms. The uppermost wire shall be approximately 305 mm (1 foot) vertically above the fabric.

The extension arm shall be made of pressed steel or malleable iron and should be designed for a 1112 N (250-lb) minimum pull-down load being applied at arm's tip.

The extension arm shall be galvanized in accordance with ASTM A153, Class Bl.

S.6.2.6 Stretcher Bar

Stretcher bars shall be galvanized steel bars not less than 6 x 19 mm (1/4 x 3/4 inch). They shall be approximately 25 mm (1 inch) less than the fabric height.

The stretcher bar shall be used for securing the fabric to all terminal posts. One bar is required for each gate and end post, and two are required for each corner and pull post.

S.6.2.7 Post Braces

Post braces are required at each gate, corner, pull, and end post. They shall consist of a strut, which shall not be less in size than the top rail, and a tension rod with turnbuckle. The rod shall be steel and have a minimum diameter of 10 mm (3/8 inch).

The strut shall be secured to the adjacent line post at approximately mid-height of the fabric. The tension rod is also secured near this area on the line pole and is anchored near the base of the corner post (or gate, pull, or end post).

Bracing members shall all be hot-dip galvanized in accordance with ASTM 153.

S.6.2.8 Tension Wire

Tension wire used in lieu of bottom rail shall not be less than No. 7 USWG galvanized steel wire.

S.6.2.9 Gate Frames

Gate frames shall be constructed of tubular steel members that should be welded at the joints. Additional horizontal and vertical struts may be required to provide for a rigid gate panel allowing for no visible sag or twist. Gate frames shall be made to have approximately 76 mm (3-inch) clearance above the road.

Fabric for the gate panels shall be the same as for the fence.

Gate frame and bracing members shall not be less than the structural equivalent of 48 mm (1.9-inch) O.D. standard pipe. Steel tension rods and turnbuckles may also be utilized. Gate frame shall have provisions for three lines of barbed wire above the fabric. All gate frame material shall be hot-dip galvanized.

S.6.2.10 Hardware

Hinges shall be heavy duty and allow 180-degree swing of all gate leaves. The hinges shall not twist or turn under the action of the gate and shall provide ease of operation.

Latches, stops, and keepers shall all be heavy duty construction of galvanized steel or malleable iron. Latches shall have a heavy-duty drop bar. The center stop shall be made to be cast in concrete and engage the drop bar. A keeper shall be provided that will secure the free end of the gate in the open position.

Hardware shall allow for gate operation from either side with provisions for securing with a padlock.

Bands, wire ties, and clips for securing fabric to top rails, line posts, terminal posts, and tension wires shall be galvanized steel and of adequate strength for the purpose intended. Aluminum wire ties of adequate strength are acceptable for this work also.

S.6.3 ERECTION

The fabric shall be placed on the outside of the posts, stretched taut, and secured to the posts, top rail, and tension wire. The fabric shall be secured to the line posts with wire ties or metal bands at maximum intervals of 356 mm (14 inches). The top and bottom edges shall be secured, respectively, to the top rail and tension wire with tie wires not exceeding intervals of 610 mm (24 inches). The fabric shall be secured to terminal posts by means of the stretcher bar that is passed through the end loops of the fabric and is secured to the terminal posts by metal bands spaced at a maximum interval of 356 mm (14 inches).

Fabric for fencing shall all either be a left-hand or right-hand weave. Rolls of fabric shall be joined together by weaving a single strand into the end of the roll to form a continuous piece.

The spacing of line posts (3 meters or 10 feet maximum) shall in general be measured parallel to the ground. All posts shall be placed vertically except as may be specifically designated otherwise, with the strong axis parallel to the fabric.

All posts shall be set in holes and backfilled with concrete. The concrete shall have a maximum compressive strength of 1720 N/cm^2 (2500 psi) at 28 days with a maximum size of aggregate of 25 mm (1 inch). The concrete shall be well worked (rodded) in the hole. The top of the footing shall be crowned to shed water.

The minimum diameter of holes for line posts shall be 229 mm (9 inches) and for terminal posts 305 mm (12 inches). See Figure 6-6 for erection details.

The minimum depth of the footing holes shall be 965 mm (38 inches).

CAUTION: The engineer should review footing depth in areas subject to extreme frost penetrations and in areas of solid rock with very little or varying amounts of soft overburden.

S.6.4 GROUNDING

Fence grounding shall be in accordance with Grounding Regulations.

5 cm (2")

61cm ± .5cm
(24" ± 1/4")

5 cm MIN.
(2")

7 cm MAX.
(2 3/4")

EXTENSION ARM

OR

CORNER POST

STRETCHER BAR

TIE WIRE

TOP RAIL

BRACE STRUT

BRACE CONNECTION

TENSION ROD & TURNBUCKLE

TENSION WIRE

TENSION WIRE STAPLE OR TIE WIRE

TOP

OR

BARBED WIRE

30cm (1 ft)

EXTENSION ARM

CONNECTION SLEEVE

LINE POST

TIE WIRE

TYPICAL FENCE COMPONENT ARRANGEMENT
(POST TYPES SHOWN ARE ILLUSTRATIVE ONLY)

GATE HINGE

BRACE STRUT

GATE POST

GATE HINGE

GATE CAP

SADDLE

GATE FENCE

EXTENSION ARM

LATCH ASSEMBLY

DROP BAR

LATCH ASSEMBLY

GATE STOP

TYPICAL GATE ARRANGEMENT
(POST TYPES SHOWN ARE
ILLUSTRATIVE ONLY)

Figure 6-6: Fence Erection Details

CHAPTER 7
STRUCTURES

Prior to the start of structure design, several factors should be evaluated that may affect the choice of material and member type selected for the structure.

Factors influencing selection of material and member type include first cost, cost of erection, deflection characteristics, cost of maintenance, availability, resistance to corrosion and other deterioration, freedom from fire hazard, appearance, size of revenue-producing load served, and temporary or permanent nature of structure.

The American Society of Civil Engineers (ASCE) is currently developing a substation structure design guide that will discuss in greater detail various structure types, loading criteria, deflection criteria, methods of structure analysis and design, and structure connection to foundations. The guide is a joint effort of utilities, manufacturers, consulting firms, and academic research groups. The guide is currently in rough draft form and is being reviewed by the groups involved.

7.1 MATERIALS

There are four basic materials used for substation structures: steel, aluminum, concrete, and wood.

7.1.1   Steel

Steel is used for most substation structures. Its availability and good structural characteristics generally make it economically attractive. Steel, however, has to have adequate protection from the elements to prevent corrosion. Galvanizing and painting are two widely used finishes for steel substation structures. Because of the protective finish, steel substation structures should not be designed for field welding or field drilling for connections. Field welding is generally uneconomical and usually requires close control over the welding conditions.

ASTM A36 steel is the standard grade of steel used for most rolled-shape members in structural design. Member stresses are usually low, and weight saving is of little advantage. However, should large loads be encountered, coupled with the need for weight reduction, a high-strength steel should be considered. Structures requiring such consideration are the line support structures. Structural steel pipe and square tube sections are normally constructed of ASTM A53 Grade B and ASTM A501 steel, respectively.

7.1.2   Aluminum

Aluminum is sometimes used for substation structures where good corrosion-resistant properties are desired. It is about one-third the weight of steel.

If aluminum is used, member types should be selected taking advantage of the optimum structural qualities of aluminum and avoiding the shapes in which aluminum members may be a problem. Deflection and torsion has to be carefully reviewed when selecting member types in aluminum.

Aluminum has a lower modulus of elasticity, $E = 6.9 \times 10^6$ N/cm^2 (10×10^6 psi), and modulus of elasticity in shear, $E = 2.6 \times 10^6$ N/cm^2 (3.8×10^6 psi), than steel, $E_s = 20 \times 10^6$ N/cm^2 and $E_s = 8.3 \times 10^6$

N/cm^2 (29 x 10^6 psi and 12 x 10^6 psi). These properties are directly related to deflection and torsional rotation.

Structures designed for aluminum are constructed of Alloy 6061-T6 and should be designed, fabricated, and erected in accordance with the Aluminum Association's *Specifications for Aluminum Structures*.

7.1.3　Concrete

Precast, prestressed concrete substation structures may be economical in coastal areas with high winds and a corrosive environment, and also when substations are located near the fabricator's plant. Special considerations are required for the foundation, erection, handling, and equipment mounting characteristics of the structure.

7.1.4　Wood

Wood may be used for substation structures. Members have to be treated with an appropriate preservative. Wood poles and members are usually readily available. Structural properties and size tolerances of wood are somewhat variable, and design considerations should take this into account. The life of a wood structure is shorter than for steel, aluminum, or concrete, and maintenance costs may be higher.

Economics is an important consideration when making a material and member type selection. The total cost over the life of the structure should be considered. This also includes the cost of fabrication and shipping, ease of erection, and cost of maintenance.

7.2　FUNCTIONAL STRUCTURE TYPES

There are essentially three types of substation structures as categorized from a structural design approach related to the function served in the substation.

7.2.1　Line Support Structures

These structures are used as line exit structures, internal strain bus structures, and line terminating structures. They consist basically of two high towers and a crossarm on which the line conductors are attached. They may be used as single-bay or multibay structures.

The major forces acting on these structures are the shield wire and conductor tensions and wind forces. Because of their large size and the magnitude of forces acting on them, these structures are usually highly stressed and require the most design effort.

7.2.2　Equipment Support Structures

These structures are commonly referred to as bus support structures, switch stands, lightning arrester stands, line trap supports, etc.

In low-profile substation design, these structures are designed primarily as vertical cantilever beams with wind and short-circuit forces being the primary design forces. Deflection may control the design size of some structures and should be reviewed in all structures.

Switch stands should be designed to be more rigid than bus supports or other structures because of the dynamic loading effect of the switch blade operation and the requirement that the switch blade has to always return (close) to the relatively small space of the saddle. Any appreciable twisting or deflection of the switch stand may prohibit this function.

7.2.3   Distribution Substation Structure

This structure is the column and beam structure, similar to a building frame. It may consist of one or several bays in length and usually is one bay wide. It may vary in height from 6 to 12 m (20 to 40 feet) or more.

The structure supports switches and other equipment. It usually will have line conductors attached to one or more sides. This structure should be designed for rigidity and flexibility in equipment location. Generally these structures are composed of box truss members.

7.3   STRUCTURE MEMBER TYPES

Three types of structure profile configurations are common in substations today. They are classified from their general physical appearance and structural member components. The types are lattice, solid profile, and semi-solid profile.

7.3.1   Lattice

The lattice structure consists primarily of angle members forming the chords and lacing of a box truss acting as a beam or column.

Depending on the function of the structure (i.e., bus support stand vs. line support structure), the design of the members may or may not be time-consuming and complex.

The lattice structure has been widely used for substation structures for many years. Its box truss beams and columns allow for an efficient use of material. Usually the lattice structure results in the least structure weight compared to other line support structures. It is also very stable and rigid. It is very easy to fabricate, galvanize, and ship. It requires a large amount of bolting and erection time in the field, unless the members are shipped preassembled, and maintenance painting, if required, is costly. Lattice structures are also aesthetically displeasing.

7.3.2   Solid Profile

The solid-profile structure is made from wide flange shapes, pipes, tapered round or polygonal shapes, and rectangular tube shapes. The aesthetic appearance, relatively short erection time, and ease of maintenance make the solid-profile structure a popular choice for equipment support structures. The weight penalty on solid-profile equipment support structures is smaller than on line support structures.

The square tube has good torsional resistance and is equal structurally about either major axis. The wide flange shape has a minor axis that may control the design. It has an open cross section and minimal resistance to torsional loads.

Wide flange shapes are more suitable for bolted structural connections and may require less welding during fabrication.

Line support structures may be made of straight or tapered tubular round or polygonal poles. The tower may be either an A-frame configuration or a single pole. Wide flange shapes may be used in the A-frame tower. Crossarms are made of straight or tapered round or polygonal members. A combined section from wide flange shapes is used for crossarms also.

Tapered poles may have telescoping or flanged splice connections when the pole is galvanized. Painted poles may have welded splice joints and are hermetically sealed to prevent oxidation inside the pole.

Tapered poles are almost always designed by the pole fabricator to the loading requirements specified by the engineer.

7.3.3   Semi-Solid Profile

The third structure type is semi-solid profile. This type of structure is made from wide flanges and pipes or tubes that form the major members, and is braced between these major members with angle bracing.

The design of this structure type is similar to the lattice structure and is very stable and rigid because of the bracing.

7.3.4   Summary

Each of the structure member types has its advantages and disadvantages, both from an economical and design viewpoint.

Lattice structures are usually economically comparable in aluminum and steel. The basic design approach is also the same. Solid-profile structures used for equipment support structures in aluminum may be as economical as steel in favorable geographical locations. Design effort for aluminum members used in equipment support structures requires more time because of buckling characteristics and weld effect on allowable stresses. However, the desirability of aluminum's good weathering characteristics and light weight are positive factors that have to also be evaluated.

7.4   DESIGN

7.4.1   Design Loads

Design loads for substation structures should be categorized by:

1. Line support structures
2. Equipment support structures

7.4.2   Line Support Structures

The design loading criteria for these structures should be very similar to the criteria for a transmission line tower. The maximum loading condition and line tension are usually furnished by the transmission engineer. For strain bus structures the substation engineer should base the design upon those design loads that will be a maximum for the various components of the structure.

A more positive determination of the structure capacity can be made if an overload is applied to the forces and the structure members are designed utilizing yield stresses. The information is also beneficial for future line changes for substation upgrading or other electrical load modifications.

The components of this structure should be able to withstand the stresses induced by the most critical loading (multiplied by an appropriate overload factor) affecting the component member.

These loadings are described in Chapter 2 and are listed here for overload factor correlation.

Overload factors for metal and prestressed concrete structures are as follows:

    a.   NESC (Heavy, Medium, Light)

        1) Wire Pull   1.65
        2) Wind   2.50
        3) Vertical   1.50

    b.   High Winds @ 15°C (60°F)

        1) Wire Pull   1.3
        2) Wind   1.3
        3) Vertical   1.3

    c.   Heavy Ice @ –1°C (30°F)

        1) Wire Pull   1.3
        2) Vertical   1.3

    d.   Other Wind & Ice Combination

        1) Wire Pull   1.3
        2) Wind   1.3
        3) Vertical   1.3

    e.   Seismic Loading

        1) All Masses   1.3

The line support structure is designed for two line angle conditions:

    1.   All wires perpendicular to the crossarm
    2.   The angle of all wires deviating from perpendicular to the crossarm at 15 degrees

Local conditions may require a larger angular deviation.

7.4.3   Deflection Consideration

In addition to the stresses, the engineer should also consider deflection limitations for line support structures. Unless particular circumstances dictate otherwise, the limitations listed may be used as guidelines:

Crossarms - Δh ≤ 1 to 1-1/2% of span for maximum tension w/ OLF
Poles - (at top) Δh ≤ 4 to 5% of height for maximum tension w/ OLF

Lattice towers and solid-profile A-frame towers usually present no problems with deflection. The single-pole-type line support structure has to be carefully reviewed for deflection limitations, particularly if it is acting as a line deadend structure and also is supporting backspan conductors.

7.4.4 Lightning Masts

Single tubular poles often are used for tall lightning masts. Give consideration to those poles where no shield wires are attached.

Include damping devices to reduce or negate vibrational forces created by the wind blowing at or near the natural frequency of the pole.

One such device may be fairly heavy steel chain, encased in a fire hose (to protect the pole finish) and suspended from the top of the pole (inside).

7.4.5 Equipment Support Structures

Design these structures for all applicable wind, ice, short-circuit, and dead and dynamic operating loads of equipment. Steel substation structures generally should conform to the requirements of Part 36 of NEMA Publication SG 6.

Ice loading is usually not the controlling design load for equipment support structures but should be reviewed.

Wind loads plus short-circuit forces usually produce the maximum stresses in the structures.

Although not normally a critical factor on bus supports and other stationary type equipment stands, deflection limitations are important for switch stands. Follow deflection limitations as specified in Section SG6-36.03 of NEMA Publication SG 6 unless special conditions dictate otherwise.

Design bus support structures and other stationary equipment stands for a reasonable amount of rigidity. Members stressed to near their allowable stresses may result in structures that perform unsatisfactorily.

Basically, the wind load is assumed for design purposes to be a statically applied load. In reality, it fluctuates in magnitude, and oscillating motion may be induced in the structures. This motion is most unpredictable but can be somewhat alleviated by selecting members that may be larger than required by the calculations and will provide reasonable rigidity for unknown effects. Allowable working stress design values should be used for equipment support structures.

7.4.6 Base Condition

Equipment support structures consisting of solid-profile members may be designed either with the base plate in full contact with the foundation or resting on leveling nuts slightly above the foundation.

The design with the leveling nuts has several advantages:

a.   It eliminates need for close tolerance work on foundation elevation and trueness of surface.

b.   It allows for some flexibility for structure alignment as a result of fabrication tolerances and buswork fit up.

c.   The base plate is not resting in any standing water on the foundation.

Anchor bolt sizes may be required to be slightly larger because of additional bending stress induced. The space between the bottom of the leveling nut and the nominal top of the foundation is usually 1.3 cm (½ inch).

7.4.7   Seismic Loads

Designing structures for seismic loading can be a very involved, time-consuming procedure involving dynamic analysis and response spectra. In certain areas of high seismic risk or when sensitive equipment is to be installed, such analysis may be necessary; however, it should be performed by trained, competent people. For most design purposes, more simplified methods can be used, such as those found in the ASCE *Substation Design Guide*, which is currently being updated and revised. The discussion presented here is based on the 1998 draft version of the ASCE *Substation Design Guide*.

Seismic or earthquake loads are environmental loads that are governed by the region of the country in which they occur. In substation design, seismic loads are not usually combined with ice and wind loads, but may be combined with short-circuit forces or operating loads if these loads can occur as a result of seismic activity.

The United States is broken into six seismic regions as shown in Figure 2-2, UBC Seismic Zone Map of the United States. A zone factor, Z, ranging from 0.0 to 0.4 is determined based on the site location. The zone factor is equivalent to the zero period acceleration (ZPA) of the ground motion. Values of "Z" are indicated in Table 7-1.

Table 7-1: UBC Seismic Zone Factors. Ref. *Uniform Building Code*, 1997, Table 16-I.
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with permission of the publisher, the International Conference of Building Officials.

Zone	0	1	2A	2B	3	4
Z	0	0.075	0.15	0.20	0.30	0.40

Substation structures are divided into four types when considering seismic loading criteria:

1.   ST1   Single- or Multi-Bay Rack   (Not supporting equipment)
2.   ST2   Single- or Multi-Bay Rack   (Supports equipment and/or conductors)
3.   ST3   Rigid Isolated Support   (Supports equipment)
4.   ST4   Flexible Isolated Support   (Supports equipment)

Rigid and flexible isolated supports (ST3 and ST4) in voltage classes greater than 121 kV, and within Seismic Zones 3 and 4, should be designed and qualified according to IEEE Std. 693, "Recommended Practices for Seismic Design of Substations." For these structures, the procedure below can be used as a check against wind and ice load cases to determine controlling load cases, but IEEE Std. 693 should be used for final design.

The design procedure described below can be used for the design of:

1. Rigid isolated supports and flexible isolated supports (Types 3 and ST4) in Seismic Zones 1, 2A, and 2B.
2. Rigid isolated supports and flexible isolated supports (Types 3 and ST4) for equipment in voltage classes 121 kV and below in Seismic Zones 3 and 4.
3. Racks (single- or multi-bay) and A-frames (Types ST1 and ST2) in all Seismic Zones. The design base shear is determined using Equations 7-1 and 7-2:

Equation 7-1

$$V = \frac{ZIC}{R_w} W$$

Equation 7-2

$$C = \frac{1.25S}{T^{2/3}}$$

Where:

- V = Total design lateral force or shear at the base
- Z = UBC Seismic Zone Factor
- R_w = Structure Type Factor
- C = Numerical Coefficient (C need not exceed 2.75)
- S = Site Coefficient for Soil Characteristic, see Table 7-2
- T = Fundamental Period of Vibration, in seconds
- I = Importance Factor
- W = Seismic Dead Load (including all rigidly attached equipment or conductor; flexible attachments, such as conductor, need not be included)

Table 7-2: Site Coefficient for Soil Characteristics. Ref. *Uniform Building Code*, 1997, Table 16-J. Reproduced from the 1997 edition of the *Uniform Building Code*[TM], copyright © 1997, with permission of the publisher, the International Conference of Building Officials.

Description	S Factor
Rock-like material, Shear Wave velocity greater than 2,500 fps or Medium-dense to dense or medium-stiff soil conditions, depth less than 200 feet	1.0
Predominantly medium-dense or medium-stiff to stiff soil conditions, depth exceeds 200 feet	1.2
Soil profile containing more than 20 feet of soft to medium-stiff clay but not more than 40 feet of soft clay	1.5
Soil profile containing more than 40 feet of soft clay, shear wave velocity less than 500 fps	2.0

The Importance Factor, I, is taken as 1.0 (based on UBC Life Safety), 1.25 (based on UBC Life Safety and functional performance after a seismic event), or 1.5 (same basis as 1.25 but for anchorage systems), depending on the importance of the structure to the electric system. The numerical coefficient, C, may be assumed to be 2.75 if the soil conditions are unknown, regardless of the soil type or period.

The Structure Type Factor, R_w, is based on the lateral force resisting system of the structure. Tables 16-N and 16-P in the *Uniform Building Code* provide a complete list of values to be used. Substation structures can be generally classified as shown in Table 7-3:

Table 7-3: Structures—Type Factor.
Ref. *Uniform Building Code*, 1997, Table 16-P.
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Structure Type	R_w
Moment-Resisting Steel Frame	6
Trussed Towers	4
Raised Tanks or Inverted Pendulum	3

Conservatively, it is recommended that a value of $R_w = 4$ be used for most rack-type structures (Types ST-1 and ST-2). Structures such as an isolated bus support (freestanding inverted-pendulum) could use a value of 3.

7.4.8   Wind Loads

Several methods of determining wind loads are used. One widely used method is found in NEMA Std. SG6, Part 36, "Outdoor Substations."

Wind pressures on flat surfaces are obtained from Equations 7-3 and 7-4:

Equation 7-3   Equation 7-4
$P_w = 0.0776V^2$ (Metric) $P_w = 0.0042V^2$ (English)

Wind pressures on cylindrical surfaces are obtained from Equations 7-5 and 7-6:

Equation 7-5   Equation 7-6
$P_w = 0.0481V^2$ (Metric) $P_w = 0.0026V^2$ (English)

Where:
P_w = Pressure on the projected area, N/m^2 (psf)
V = Design wind velocity, km/hr (mph)

The design wind velocity for a given area is determined from the probable wind velocity over the design life of the structure, say a 50-year period of recurrence. This information can be obtained from Figure 2-1 or may be derived from local climatological data.

For wind loading on lattice structures, the projected area used is one and one-half times the area of exposed members.

An alternative approach to calculating wind load on substation structures can be found in the ASCE *Substation Design Guide*, currently under development. The approach in this guide is based on ANSI/ASCE Std. 7-95, "Minimum Design Loads for Buildings and Other Structures."

Under the ANSI/ASCE Std. 7-95 approach, the "3-second gust" wind speed at a height of 10 meters (33 feet) is used as the basic wind speed for design replacing the "fastest mile" wind speed data in the ASCE Std. 7-93 basic wind speed map. The basic wind speed to be used can be obtained from Figure 2.1. Based on the ASCE *Substation Design Guide* and ANSI/IEEE Std. 605, "IEEE Guide for Design of Substation Rigid Bus Structures," the wind load on a structure can be determined using Equation 7-7:

Equation 7-7
$$P_w = CC_D K_Z G_F V^2 I$$

Where:

W	=	Wind pressure N/m² [lb/ft²]
C	=	$6.13*10^{-1}$ for metric units [$2.56*10^{-3}$ for English units]
C_D	=	Drag coefficient
K_Z	=	Height and exposure factor
G_F	=	Gust factor
V	=	Basic wind speed at 10 meters [33 feet] above ground, m/hr [mi/hr]
I	=	Importance factor

Each of the above variables is briefly discussed below.

Constant, C. This is a constant that yields a value for F_W in terms of metric or English units.

Drag coefficient, C_D. The wind load on a conductor or a structure varies with its shape. The drag coefficient reflects that variation. The coefficient can vary between 1.0 for round, smooth shapes to about 2.0 for flat surfaces. For a more detailed discussion of the variation in values to use, see ANSI/IEEE Std. 605 or ASCE Std. 74, *Guidelines for Electrical Transmission Line Structural Loading*.

Height and exposure factor, K_Z   In the height range from 0 meters [feet] to 9.1 meters [30 feet] and for exposure categories A, B, and C, the height and exposure factor $K_Z = 1.0$. For exposure category D, $K_Z = 1.16$. Each of these exposure categories is explained in detail in ANSI/ASCE Std. 7-95. A summary description is provided below:

> **Exposure A:** Large cities' centers with at least 50 percent of the structures having a height greater than 21.3 meters [70 feet].

> **Exposure B:** Urban and suburban areas, wooded areas, or other terrain with numerous closely spaced obstructions having the size of single-family dwellings or larger.

> **Exposure C:** Open terrain with scattered obstructions having heights generally less than 9.1 meters [30 feet]. Open country and grassland is included in this category.

> **Exposure D:** Flat, unobstructed areas exposed to wind flowing over open water for a distance of at least 1.61 km [1 mile].

Gust factor, G_F. A gust factor of 0.8 should be used for exposure categories A and B, and 0.85 should be used for exposure categories C and D.

Basic wind speed, V. Figure 2-1 should be used for this value.

Importance factor, I. An importance factor of 1.15 should be used for electric substations. See ANSI/ASCE Std. 7-95 for a discussion of the importance factor.

7.4.9   Construction Loading

Consideration should also be given to construction loads that can be periodically imposed on structures such as pulling and hoisting equipment into place. While such conditions do not usually govern design,

they should be evaluated.

7.4.10   Loading Combination for Design

In addition to designing equipment stands for the extreme loads, bus supports are also designed for a combination load of extreme wind and short-circuit loads. The load combination design should be limited to calculations of stress and should not consider deflection of the structure.

7.4.11   Typical Design Approach

There are basically two approaches to design of steel structures: Allowable Stress Design (ASD) and Load and Resistance Factor Design (LRFD).

The ASD approach is defined by the American Institute of Steel Construction's (AISC) *Manual of Steel Construction, ASD*. In the ASD, the stresses induced by various service loads (wind, ice, etc.) in a selected member are compared to allowable stresses established in the AISC manual.

In LRFD, load factors are applied to the service loads, or loads the structure is actually expected to see. Then a member is selected that will have sufficient strength to resist the factored loads. In addition, the theoretical member strength is reduced by an applied resistance factor. The selection of the member has to satisfy the following:

$$\boxed{\text{Factored load} \leq \text{Factored strength}}$$

The "factored load" is the sum of all the working loads to be resisted by the member. Each load is multiplied by its own load factor. Dead loads, for example, will have load factors that are different from live load factors. The "factored strength" is the theoretical strength multiplied by a resistance factor. Load and Resistance Factor Design of steel structures is very much similar to the approach to reinforced concrete design used for several years in the American Concrete Institute's Building Code where it is known as strength design.

The benefit of ASD is that it is straightforward and familiar to most structural engineers. With the LRFD approach, load factors model the likelihood, or probability of certainty, of various types of loads. For example, dead loads can typically be determined with more certainty than can live loads. Therefore, the load factor for a dead load is less than that for a live load.

The resistance factors applied to the member's theoretical strength account for uncertainties in material properties, design theory, and fabrication and construction practices. One might say that the LRFD is a more realistic approach to structure design. The guidelines and specifications for LRFD are published in AISC's *Manual of Steel Construction*, *Load Factor & Resistance Factor Design.*

Several examples are illustrated depicting the design of the main member for a single-phase bus support. These examples show a typical approach for the design of most equipment support structures using allowable stress design. The examples include a square tube, a wide flange, and a lattice column, all composed of steel.

Lighter weight members may still meet the loading and deflection criteria. However, smaller size members may present fabrication problems in the lattice structure.

In general, for voltages up to 230 kV, structures using tubular members are as economical as lattice or wide flange structures when weight, ease of fabrication, and ease of erection are considered.

7.4.11.1   Design Example: Design a single-phase bus support for a substation in Lansing, Michigan, given the following information:

- Height of bus centerline above foundation 5.5 m (see Figure 7-1)
- Schedule 40 aluminum bus 100 mm (mass = 5.51 kg/m)
- Maximum short-circuit force 550 N/m
- Short-circuit reduction factor 0.66
- Bus support spacing 6.0 m
- Insulator 2.0 m high, 0.28 m diameter, and 140 kg
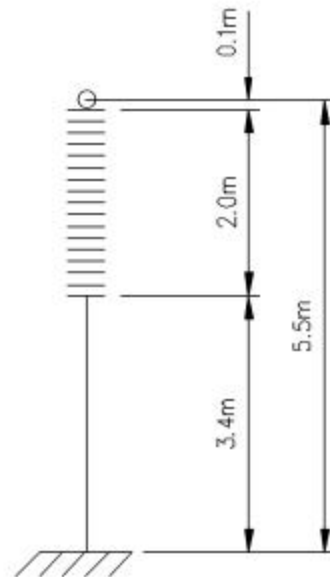
Figure 7-1: Single-Phase Bus Support

a.   Design a tubular structure, A500 or A501 steel.

Short-Circuit Loading

F_{sc} = 6.0 m x 0.66 x 550 N/m = 2178 N
Mom @ base = 5.5 m x 2178 N = 11,980 N-m

Wind Loading

Extreme 50-year wind 112.6 km/hr
For flat surfaces: $P_w = 0.0776 (112.6)^2 = 984 \text{ N/m}^2$
For cylindrical surfaces: $P_w = 0.0481 (112.6)^2 = 610 \text{ N/m}^2$
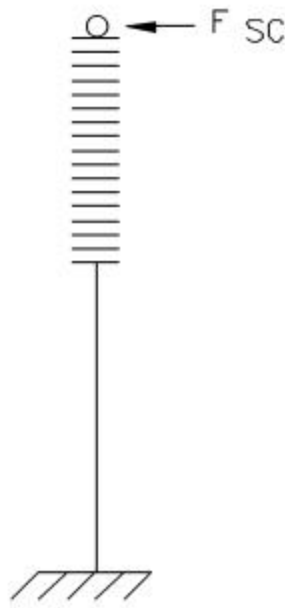
Figure 7-2: Tubular Structure—Short-Circuit Loading
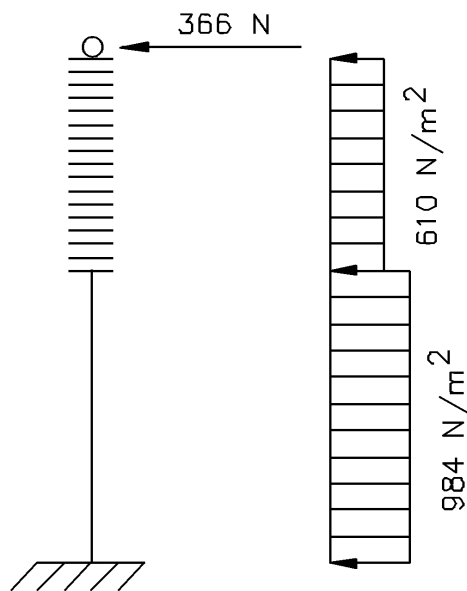
Figure 7-3: Tubular Structure—Wind Loading

Description	Force		Moment Arm	Moment @ Base
Wind on Bus	6m x 610 N/m^2 x 0.1 m^2/m =	366 N	5.5 m	2013 Nm
Wind on Insulator	2m x 610 N/m^2 x 0.28 m^2/m =	342 N	4.4 m	1505 Nm
Wind on Structure (assume 20 cm square)	3.4m x 984 N/m^2 x 0.20 m^2/m =	669 N	1.7 m	1137 Nm
TOTALS		1377 N		4655 Nm

Heavy Ice Loading (25.4 mm)
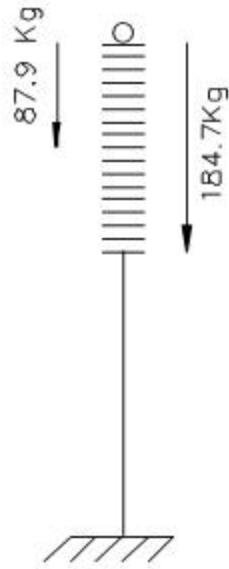
Figure 7-4: Tubular Structure—Ice Loading

Ice density = 913.0 kg/m^3 (57 pcf)

Description		Load
Ice on Bus	$\left[(0.151 \text{ m})^2 - (0.100 \text{ m})^2\right]\frac{\pi}{4}$ x 913 kg /m^3 =	9.14 kg/m
Ice & Bus	$9.14 \; kg/m + 5.51 \; kg/m =$	14.65 kg/m
Ice on Insulator	$\left[(0.331 \text{ m})^2 - (0.28 \text{ m})^2\right]\frac{\pi}{4}$ x 913 kg/m^3 =	22.34 kg/m
Ice & Insulator	$22.34 \; kg/m \; x \; 2m + 140 kg =$	184.7 kg

$$f_a = \frac{(14.65 \; kg/m \; x \; 6.0 \, m + 184.7 \; kg + 3.4 \; m \; x \; 28.89 \; kg/m) \, 9.80 \; N/kg}{14.5 \; cm^2}$$

$$= 250.6 \frac{N}{cm^2}$$

$$\frac{kl}{r} = 2 \frac{(340 \; cm)}{8.05 \; cm} = 84$$

$$F_a = 10335 \frac{N}{cm^2} > 250.6 \frac{N}{cm^2} \qquad okay$$

Seismic Loading
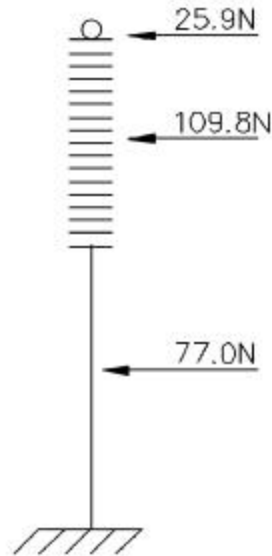
Figure 7-5: Tubular Structure—Seismic Loading

$$V = \frac{ZIC}{R_w} W$$

$$V = \frac{0.075(1.5)(2.75)}{3} W$$

V = 0.08W
Z = 0.075 (Lansing, Michigan, is in Zone 1)
I = 1.15
C = 2.75 (assumed)
R_w = 3

Description	Force		Moment Arm	Moment @ Base
Seismic on Bus	6 m x (5.51 kg/m) 9.8 (0.08) =	25.9 N	5.5 m	142.4 Nm
Seismic on Insulator	140 kg (9.8) 0.08 =	109.8 N	4.4 m	483.1 Nm
Seismic on Structure	3.4 m (28.89 kg/m) 9.8 (0.08) =	77.0 N	1.7 m	130.9 Nm
TOTALS		132.9 N		756.4 Nm

The combined loading of wind and short-circuit forces produce the greatest forces and moment at the base design for this condition. Therefore, heavy ice and seismic forces are not critical for this structure.

For the cantilever structure, bending and deflection are the principal concerns.

Try a 20.3 cm x 20.3 cm x 0.48 cm steel tube:

$$f_b = \frac{M}{S} = \frac{16,635\ Nm(10\ cm/m)}{234.3\ cm^3} = 7100\ \frac{N}{cm^2}$$

$$F_b = 0.60\ F_y = 15160\ \frac{N}{cm^2} > 7100\ \frac{N}{cm^2} \quad okay$$

Check Deflection
(For wind only)
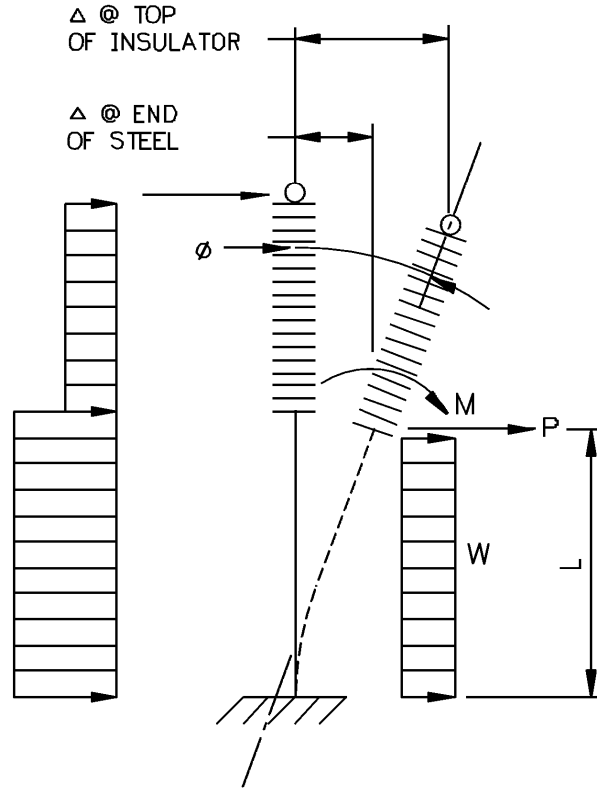
Figure 7-6: Tubular Structure—Deflection Equivalent Loadings

Deflection Equivalent Loadings

Δ @ end of steel = $\Delta_1 + \Delta_2 + \Delta_3$

Where: $\Delta_1 = \dfrac{Pl^3}{3EI}$, Wind on insulator and bus

$\Delta_2 = \dfrac{Wl^4}{8EI}$, Uniform wind on structure

$\Delta_3 = \dfrac{Ml^2}{2EI}$, Moment at insulator base

$\Delta = 0.19 \text{ cm} + 0.07 \text{ cm} + 0.13 \text{ cm} = 0.39 \text{ cm}$

$\Theta \left(slope\right)$ @ end of steel $= \Theta_1 + \Theta_2 + \Theta_3$

Where : $\Theta_1 = \dfrac{Pl^2}{2EI}$, Wind on insulator and bus

$\Theta_2 = \dfrac{Wl^3}{6EI}$, Uniform wind on structure

$\Theta_3 = \dfrac{Ml}{EI}$, Moment at insulator base

$\Theta = 0.00086 \text{ rad} + 0.00027 \text{ rad} + 0.00079 \text{ rad} = 0.00192 \text{ rad}$

Δ @ top of insulator $= 0.39 \text{ cm} + 200 \text{ cm} \sin \Theta = 0.77 \text{ cm}$

$$\frac{0.77 \, cm}{550 \, cm} = \frac{1}{714} \quad < \quad \frac{1}{200} \quad okay$$

Acceptable criteria for bus support structure deflections may be taken as 1/200 of the bus height.

The analysis shows that for the given conditions a structural tube 20.3cm x 20.3cm x 0.48cm will be suitable.

b.   Design a wide flange structure using A36 steel.

The maximum combined loads on this structure are the same as in the first example. Again, by inspection, heavy ice loading is not critical. Therefore, consider only bending and deflection.

Assume W 20.3cm x 35.7 kg/m

$$f_{bxx} = \frac{M}{S_{xx}} = \frac{16,635 \text{ Nm} \, (100 \, \text{m}/\text{m})}{341 \, \text{cm}^3} = 4878 \, \frac{N}{cm^2}$$

$$f_{byy} = \frac{M}{S_{yy}} = \frac{2642 \, Nm \, (100 \, cm/m)}{92 \, cm^3} = 2872 \, \frac{N}{cm^2} \, (wind \, only)$$

F_b is reduced when the unbraced compression flange is considered

$$F_{bxx} = 14,200 \, N/cm^2 > 4878 \, N/cm^2 \quad okay$$
$$F_{byy} = 15,170 \, N/cm^2 > 2872 \, N/cm^2 \quad okay$$

Check Deflection
(For wind only)

Δ_{xx} @ end of steel $= 0.13 \text{ cm} + 0.05 \text{ cm} + 0.09 \text{ cm} = 0.27 \text{ cm}$

$\Theta = .00060 \text{ rad} + 0.00019 \text{ rad} + 0.00055 \text{ rad} = 0.00134 \text{ rad}$

Δ_{xx} @ insulator $= 0.27 \text{cm} + 200 \text{ cm} \sin \Theta = 0.54 \text{ cm}$

$$\frac{0.54 \, cm}{500 \, cm} = \frac{1}{926} < \frac{1}{200} \quad okay$$

c. **Design a lattice structure, A36 steel** (assume box truss 38.1 cm square).
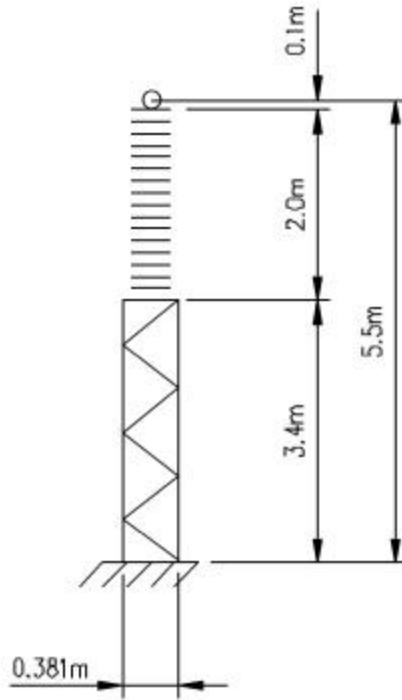
Figure 7-7: Lattice Structure

Short-Circuit Loading

F_{sc} = 6.0 m x 0.66 x 550 N/m = 2178 N
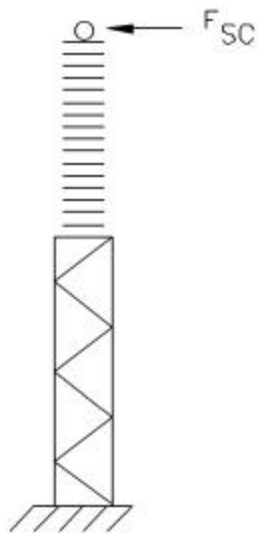
Figure 7-8: Lattice Structure—Short Circuit Loading

Mom @ base = 5.5 m x 2178 N = 11,980 Nm

Wind Loading

Assume chord angles = 6.35 cm

Assume lacing angle = 4.45 cm
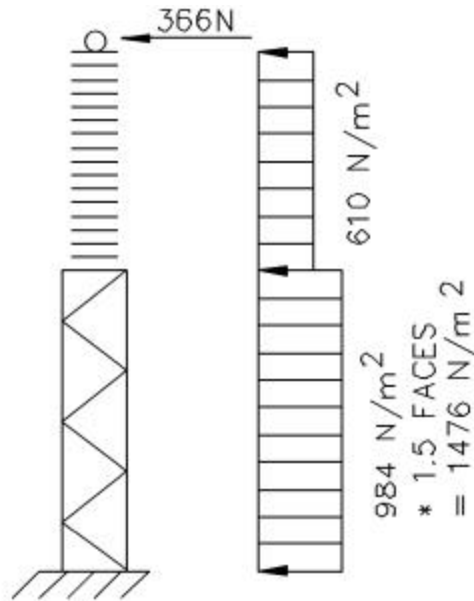
Figure 7-9: Lattice Structure—Wind Loading

Description	Force		Moment Arm	Moment @ Base
Wind on Bus	6 m x 610 N/m² x 0.1 m²/m =	366 N	5.5 m	2013 Nm
Wind on Insulator	2 m x 610 N/m² x 0.28m²/m =	342 N	4.4 m	1505 Nm
Wind on Structure	3.4m x 1476 N/m² x 0.19m²/m =	953 N	1.7m	1620 Nm
TOTALS		1661 N		5138 Nm

By inspection, heavy ice and seismic loading will not result in the maximum design loads.

Moment at the base causes tension and compression in the chord angles.

C = Tensile or compressive force

$$C = \frac{17{,}118 \text{ Nm}}{2[0.381 \text{ m} - 2(0.014 \text{ m})]} = 24{,}250 \text{N per leg}$$

P = Applied load

$$P + C = \frac{1373\,N + 6\,m(54\,N/m)}{4} + 24{,}250\,N = 24{,}670\,\frac{N}{leg}$$

$$\frac{\text{kl}}{\text{r}_z} = \frac{1.0(38.1)}{1.26} = 30 \quad \frac{\text{kl}}{\text{r}_y} = \frac{1.0(57)}{1.98} = 30 \quad \text{F}_a = 13{,}780\,\frac{\text{N}}{\text{cm}^2}$$

$$f_a = \frac{24{,}670\,N}{5.94\,cm^2} = 4153\,\frac{N}{cm^2} < 13{,}780\,\frac{N}{cm^2} \quad okay$$

Δ @ top of steel = 0.07 cm + 0.03 cm + 0.05 cm = 0.15 cm

Θ = 0.00030 rad + 0.00010 rad + 0.00028 rad = 0.00068 rad

Δ @ top of insulator = 0.15 cm + 200 cm sin Θ = 0.29 cm

$$\frac{0.29\ cm}{550\ cm} = \frac{1}{1897} < \frac{1}{200} \qquad okay$$

A summary of mass and deflection for the structure design example is shown in Table 7-4.

Table 7-4: Summary of Mass and Deflection—Design Example

Description	Mass of Structure	Deflection at Insulator	Comments
20.3 cm x 20.3 cm x 0.48 cm	122 kg	0.77 cm	Largest deflection
W20.3 x 35.7 kg/m	154 kg	0.54 cm	Heaviest structure
Box Truss, Chord Angles 6.35 cm x 6.35 cm x 0.48 cm Lacing Angles 4.45 cm x 4.45 cm x 0.48 cm	118 kg	0.29 cm	Smallest deflection

7.5 FASTENERS

Three types of structural bolts are typically used in substation structure design. These bolts are designated by ASTM Standard Specifications A394, A307, and A325. For all but the most severely loaded structures, the A394 and A307 bolts will usually be adequate.

If possible, one type of structure bolt and one diameter should be used in any one structure and throughout all the substation structures.

7.5.1   ASTM A394

ASTM Standard Specification A394 covers galvanized hex head bolts including hex nuts with sizes from 12.7 to 25.4 mm (½ to 1 inch) in diameter.

7.5.2   ASTM A307

Non-galvanized regular square or hex head bolt and nuts in diameters ranging from 6.35 to 101.6 mm (¼ to 4 inches) in diameter are covered by ASTM Standard Specification A307. This specification is also used for anchor bolts conforming to the requirements of ASTM A36 structural steel. For substation usage, Grade A bolts are used. Hot-dip galvanizing in accordance with ASTM A153 is required for substation applications.

7.5.3   ASTM A325

When high-strength bolts are required, ASTM Standard Specification A325 High Strength Bolts may be used. High-strength bolts are available in sizes from 12.7 to 38.1 mm (½ to 1½ inches) in diameter. Bolts, nuts, and washers should be galvanized in accordance with ASTM A153, Class C. Nuts should conform to ASTM A563, Grade DH.

Some tabulated bolt values for single shear are given in Table 7-5. These values may be used for substation structure design when "working stresses" or "yield stresses" are used.

Table 7-5: Suggested Allowable Bolt Shear

SINGLE SHEAR ON BOLTS, KIPS (English Units) WORKING STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (ksi)	Nominal Diameter (inches)				
		½	5/8	¾	7/8	1
A307	10.0	1.96	3.07	4.42	6.01	7.85
A394	15.0	2.95	4.60	6.63	9.02	11.78
A325	21.0	4.12	6.44	9.28	12.63	16.49

SINGLE SHEAR ON BOLTS, KIPS (English Units) YIELD STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (ksi)	Nominal Diameter (inches)				
		½	5/8	¾	7/8	1
A307	18.0	3.53	5.52	7.95	10.82	14.14
A394	30.0	5.89	9.20	13.25	18.04	23.56
A325	36.0	7.07	11.05	15.91	21.64	28.28

SINGLE SHEAR ON BOLTS, kN (Metric Units) WORKING STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (kN/ cm^2)	Nominal Diameter (mm)				
		12.70	15.88	19.05	22.23	25.40
A307	6.89	8.73	13.65	19.65	26.75	34.94
A394	10.34	13.10	20.46	29.46	40.09	52.37
A325	14.48	18.35	28.66	41.27	56.17	73.37

SINGLE SHEAR ON BOLTS, kN (Metric Units) YIELD STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (kN/ cm^2)	Nominal Diameter (mm)				
		12.70	15.88	19.05	22.23	25.40
A307	12.41	15.73	24.57	35.38	48.15	62.90
A394	20.68	26.21	40.94	58.96	80.24	104.81
A325	24.82	31.45	49.12	70.74	96.28	125.75

Based on:
1. AISC Manual of Steel Construction, ASD, 9th ed.
2. AISC Manual of Steel Construction, RLFD, 2d ed.
3. ASTM A394 Standard Specification for Steel Transmission Tower Bolts.
4. ASCE Manuals and Reports on Engineering Practice No. 72, Design of Steel Transmission Pole Structures, 2d ed.

Because of the repeated loads, those structures using A307 or A394 bolts should also incorporate either lockwashers or locknuts to prevent loosening of the connections. Standard washers are not normally used with these bolts.

7.6 WELDING

All welding of structural steel should be in accordance with the latest edition of the *Structural Welding Code*, D1.l of the American Welding Society.

In addition to the required design welds, structures that are to be galvanized should have all joints sealed with a small continuous seal weld. This is to help prevent corrosion or small crevices or cracks between two pieces of abutting steel that the acid bath can penetrate, but not the molten zinc. This is covered in ASTM A385.

7.7 FINISHES

7.7.1 Galvanizing

Galvanized steel has found wide application for substation structures. Hot-dip galvanizing has been the most widely used finish on steel substation structures for the following reasons:

   a. It is economical (initial cost, touch-up, and general maintenance).
   b. It provides good resistance to most corrosive environments.
   c. It has "self-healing" properties against minor abrasions.
   d. It requires little or no maintenance in most substation applications.

New structures are galvanized in accordance with ASTM Standard Specification A123. Safeguards against embrittlement and warpage and distortion during galvanizing should be in conformance with ASTM Standard Specification A143 and A384, respectively. Galvanized members that are marred in handling or erection or that have had corrective work done should be touched up with a zinc-rich paint.

All bolts and steel hardware should be galvanized in accordance with ASTM Standard Specification A153 for Class C material.

7.7.2 Painting

When painted structures are desired, there are several systems available. Consultation with reputable paint suppliers is recommended. Painting System Specification No. 1.04, SSPC –PS 1.04, from the Steel Structures Painting Council is one paint system that is applicable for galvanized and non-galvanized substation structures. The following is a summary of the system from the seventh edition of the Steel Structures Painting Council's *Systems and Specifications* manual.

Surface Preparation: The surface shall be thoroughly cleaned of all oil, grease, dirt, loose mill scale, and other detrimental substances. "Hand tool cleaning" is the minimum surface preparation required for this oil-based system. Depending upon condition of the surface "power tool cleaning" may be necessary. "Solvent cleaning" is only required for new galvanized structures. Specifications for these cleaning systems are outlined in the SSPC manual.

Paints:

Primer:	The system calls for a zinc dust–zinc oxide primer that conforms to federal specification TT-P-641G Type 1, which is a linseed oil primer.
Intermediate Coat:	This second coat uses SSPC-Paint 104, which is a white or tinted alkyd paint that has good weathering ability and is suitable for exterior exposures. This paint is intended for brush or spray applications and works well as either an intermediate or top coat. There are four types that are color dependent:

Type 1 – white
Type 2 – medium to light gray to tan
Type 3 – light green
Type 4 – dark or forest green

Finish Coat:	Same as intermediate coat, but the color has to be specified.
Dry Film Thickness:	This three-coat paint system calls for a minimum paint thickness of 4.5 mils. This consists of a 2.0 mil primer coat, a 1.5 mil intermediate coat, and a 1.0 mil finish coat. The measurements shall be in accordance with SSPC-PA 2, "Measurement of Dry Paint Thickness with Magnetic Gages."

Painted structures should be primed and receive the intermediate coat in the shop.   The finish coat may either be applied in the shop or in the field. The finish coat can be applied under ideal conditions in the shop; however, the structure finish may be marred during shipment or erection requiring field touch-up. The SSPC manual gives additional specifications for touch-up painting and maintenance painting as well as providing alternative finish coat systems.

7.7.3 Wood Preservatives

Wood preservatives for poles shall conform to that specified in RUS Bulletin 1728F-700, "Specification for Wood Poles, Stubs and Anchor Logs" (Electric).

All other timber shall be fully treated in accordance with RUS Bulletin 1728H-701, "Specification for Wood Crossarms (Solid and Laminated), Transmission Timbers and Pole Keys" (Electric). Where framing and drilling are necessary for construction purposes, an approved preservative should be applied to the exposed, untreated wood.

7.8 COMPUTER PROGRAMS

Today, computers are widely used in the design of substation steel structures. Though there are numerous design programs available for use on a personal computer, most of them use a basic approach.

7.8.1 Model Geometry

The structure, whether a simple bus support or a more involved multi-bay switch rack, is defined by nodes (or joints) and by members (or elements). The nodes are either automatically numbered by the program or are defined by the user. Most programs accommodate a three-dimensional model, and the nodes are located in a Cartesian coordinate system by input of X, Y, and Z coordinates. The members are then defined and "connected." Member end points (node numbers) are identified, and the members are assigned numbers, either by the program or the user. Material properties, such as the modulus of

elasticity, weight density, and the allowable yield stress, are then defined. In many programs the material, such as concrete, wood, or steel, can be selected from a menu and all the properties automatically defined. After material properties are defined, section properties of the members are then input. Section properties include cross-sectional area, moment of inertia, and torsional properties. Most programs allow the user to identify a standard AISC cross section, for example W8X31, with all the associated section properties built into the program's database. After node, member, and section properties are defined, the member end restraints and base fixity are defined. Members are considered "fixed," or rigid and continuous unless the end of the member is released in rotation or translation by the user. A column base restraint is defined on the basis of the connection details. If it is firmly fixed with four anchor bolts with the column welded directly to the base plate, the end restraint can be defined in the model as fixed. However, if the column is connected to the base plate by two anchor bolts, the end restraint can be modeled with a pinned connection, or free to rotate but restrained in translation.

7.8.2 Load Input

Loads are applied to the structure as either point or distributed loads. With modern structural analysis programs, the point loads can be linear loads (kN) or applied moments (kN-m) in any direction anywhere along the length of the member. Distributed loads can be uniform or can vary in magnitude, and can be applied over all or any portion of the member. Various load cases are defined, such as extreme wind, ice loads, equipment, and gravity loads, and then these separate load cases are combined along with appropriate load factors.

7.8.3 Computer Output

After the computer model of the structure has been created and the loads entered, the program is executed. The output from a structural analysis program provides all the information needed by the engineer to completely design the structure. The information typically includes forces at each joint (axial forces, shear, and bending moments) and structure reactions to be used in foundation design. Also included are member stresses and deflections at various points along the member. Some programs provide AISC stress checks and suggested member sizes to be used in a subsequent iteration of the program.

As noted above, there are many structural analysis programs available on the market. A small sample of these are listed below. Sample input and output from RISA-3D for a simple "T" structure provided for reference can be found in the Appendix D to this chapter.

SAP2000
Computers and Structures, Inc.
1995 University Ave.
Berkley, CA 94704
Phone: (510) 845-2177

RISA-3D
RISA Technologies
26212 Dimension Drive, Suite 200
Lake Forest, CA 92630
Phone: (800) 332-7472

STAAD-III
Research Engineers
22700 Savi Ranch
Yorba Linda, CA 92887-4608
Phone: (714) 974-2500

StruCAD*3D
Zentech, Inc.
8582 Katy Freeway, Suite 205
Houston, TX 77024
Phone: (713) 984-9171

7.9   REFERENCES

Aluminum Association, "Aluminum Standards and Data."

Aluminum Association, *Specifications for Aluminum Structures*.

American Concrete Institute, *Building Code.* Farmington, Mich.: ACI, 1995.

American Institute of Steel Construction (AISC), *Manual of Steel Construction*, AISC M016-1989, ASD, 9th ed.

American Institute of Steel Construction (AISC), *Manual of Steel Construction, Load Factor & Resistance Factor Design*, AISC M015.

American Institute of Steel Construction (AISC), "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," AISC S326-1978.

American Institute of Timber Construction Std. 102, "Standards for the Design of Structural Timber Framing."

American Institute of Timber Construction Std. 116, "Guide Specifications for Structural Glued Laminated Timber for Electric Utility Framing."

American Institute of Timber Construction, *Timber Construction Manual.*

American Society of Civil Engineers (ASCE), *Substation Design Guide* (under revision).

American Society of Civil Engineers (ASCE), ASCE Std. 7-93, "Basic Wind Speed Map."

American Society of Civil Engineers (ASCE), ASCE Std. 74, "Guidelines for Electrical Transmission Line Structural Loading."

American Society of Civil Engineers (ASCE), "Design of Steel Transmission Pole Structures."

American Society of Civil Engineers (ASCE), *Electrical Transmission Line and Tower Design Guide*.

American Society of Civil Engineers (ASCE), *Substation Structure Design Guide* (under development). Draft 1998.

American Society of Civil Engineers (ASCE), Manuals and Reports on Engineering Practice No. 72, "Design of Steel Transmission Pole Structures," 2d ed.

American Welding Society Std. Dl.l, *Structural Welding Code.*

ANSI/ASCE Std. 7-95, "Minimum Design Loads for Buildings and Other Structures."

ANSI/IEEE Std. C2, *National Electrical Safety Code*.

ANSI/IEEE Std. 605, "IEEE Guide for Design of Substation Rigid-Bus Structures."

ASTM Std. A36, "Specification for Structural Steel."

ASTM Std. A53, "Specification for Pipe, Steel, Black and Hot-Dipped, Zinc Coated Welded and Seamless Steel Structure."

ASTM Std. A123, "Specification for Zinc (Hot-Galvanized) Coatings on Products Fabricated From Rolled, Pressed and Forged Steel Shapes, Plates, Bars and Strip."

ASTM Std. A143, "Recommended Practice for Safeguarding Against Embrittlement of Hot-Dip Galvanized Structural Steel Products and Procedure for Detecting Embrittlement."

ASTM Std. A153, "Specification for Zinc Coating (Hot-Dip) on Iron and Steel Hardware."

ASTM Std. A307, "Specification for Carbon Steel Externally and Internally Threaded Standard Fasteners."

ASTM Std. A325, "Specification for High-Strength Bolts for Structural Steel Joints, Including Suitable Nuts and Plain Hardened Washers."

ASTM Std. A384, "Recommended Practice for Safeguarding Against Warpage and Distortion During Hot-Dip Galvanizing of Steel Assemblies."

ASTM Std. A385, "Practice of Providing High-Quality Zinc Coatings (Hot-Dip)."

ASTM Std. A394, "Specification for Galvanized Steel Transmission Tower Bolts and Nuts."

ASTM Std. A501, "Specification for Hot-Formed Welded and Seamless Carbon Steel Structural Tubing."

ASTM Std. A563, "Specification for Carbon and Alloy Steel Nuts."

Federal Specifications and Standards No. TT-P-57B, "Paint, Zinc Yellow-Iron Oxide-Base, Ready Mixed."

Federal Specifications and Standards No. TT-P-641D, "Primer Coating: Zinc Dust-Zinc Oxide (for Galvanized Surfaces)."

IEEE Std. 693, "Recommended Practices for Seismic Design of Substations."

NEMA Std. SG6, "Power Switching Equipment, Part 36, Outdoor Substations."

NEMA Std. TTl-1977, "Tapered Tubular Steel Structures."

RUS Bulletin 1728F-700, "RUS Specification for Wood Poles, Stubs and Anchor Logs"

RUS Bulletin 1728H-701, "RUS Specification for Wood Crossarms (Solid and Laminated), Transmission Timbers and Pole Keys"

Steel Structures Painting Council Std. SSPC-PA 2, "Measurement of Dry Paint Thickness with Magnetic Gages," 1995.

Steel Structures Painting Council Std. SSPC-PS 1.04, "Three-Coat Oil-Alky (Lead- and Chromate-Free) Painting System for Galvanized or Non-Galvanized Steel (with Zinc Dust-Zinc Linseed Oil Primer)," 1995.

Steel Structures Painting Council Std. SSPC-SP-1, "Solvent Cleaning," 1995.

Steel Structures Painting Council Std. SSPC-SP-2, "Hand Tool Cleaning," 1995.

Steel Structures Painting Council, *Systems and Specifications*, 7th ed.

U.S. Department of the Interior, "The BOCA Building Code."

U.S. Department of the Interior, "Bureau of Reclamation Design Standard No. 10 Transmission Structures."

U.S. Department of the Interior, *The Uniform Building Code.*

APPENDIX D
RISA-3D INPUT AND OUTPUT FOR A SIMPLE "T" STRUCTURE


```
RISA-3D (R) Version 3.01
                                        Job :
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                                                    File: TERMSTND

    Terminator Structure
    John D. Engineer


    ===========================================================================

    Units............................ US Standard
    Steel Code....................... AISC 9th Edition ASD
    Allowable Stress Increase Factor.. 1.333
    Include Shear Deformation......... Yes
    Include Warping.................. Yes
    No. of Sections for Member Calcs.. 5
    Do Redesign...................... Yes
    P-Delta Analysis Tolerance....... 0.50%
    Vertical Axis.................... Y

    ==========================< Joint Coordinates >==========================
     Joint          X             Y             Z            Joint
      No        Coordinate    Coordinate    Coordinate     Temperature
    ------------------ft-----------ft-----------ft-------------øF-----------
        1          0.000         0.000         0.000         70.00
        2          0.000        13.250         0.000         70.00
        3         -2.500        13.250         0.000         70.00
        4          2.500        13.250         0.000         70.00

    =========================< Boundary Conditions >=========================
    Joint   +--------- Translation --------+  +--------- Rotation ----------+
     No       X            Y            Z          Mx          My          Mz
    -----------K/in-------K/in-------K/in------K-ft/rad---K-ft/rad---K-ft/rad---
        1 Reaction    Reaction    Reaction    Reaction    Reaction    Reaction

    ========================< Materials (General) >=========================
    Material    Young's       Shear    Poisson's Thermal   Weight      Yield
      Label     Modulus      Modulus     Ratio    Coef.    Density    Stress
    -------------Ksi---------Ksi---------------10^5øF----K/ft3-------Ksi------
     STL       29000.00     11154.00   0.3000  0.65000    0.490      36.00

    ==============================< Sections >==============================
    Section   Database  Material         As   As    I       I      Torsion T
     Label      Shape     Label    Area  yy   zz    yy      zz      J      C
    ---------------------------------in^2-------------in^4------in^4------in^4---
    COL       W8X28        STL      8.25 1.2  1.2   21.70   98.00    0.54
    BM1       W6X15        STL      4.43 1.2  1.2    9.32   29.10    0.10

    ==============================< Members >===============================
    Member    Joints    x Axis Section End Releases   Offsets       Inactive?
    No   I    J   K Rotate  Set  I: MMM J: MMM I-End  J-End Label    Length
    ----------------------------------xyzxyz-xyzxyz---in-----in------------ft---
        1   1    2            COL                                         13.25
        2   2    3            BM1                                          2.50
        3   2    4            BM1                                          2.50
```

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========================< AISC,NDS Parameters >==========================
      Section  Length  Lb-yy  Lb-zz  Lcomp  K    K    Cmyy  Cmzz Cb,B Sway
Member Set               le2    le1  le-bend yy   zz   CH               y z
--------------ft------ft------ft------ft---------------------------------
    1 COL    13.25                            2.10 2.10
    2 BM1     2.50                            2.10 2.10
    3 BM1     2.50                            2.10 2.10


========================< Basic Load Case Data >=========================
BLC            Basic Load Case                   Load Type Totals
No.            Description              Nodal   Point  Dist.  Surface
------------------------------------------------------------------------
 1      Dead Load                        5
 2      Extreme Ice                      5       3
 3      Extreme Wind                     8       1
 4      Extreme Wind Z                   7       3
 5      Nesc Heavy in x                 10       4
 6      Nesc Heavy in z                  8       6
 7      Short Circuit                    2


=====================< Member Point Loads, BLC 1 >======================
          Joints
Member    I     J     Direction      Magnitude         Location
----------------------------------------K,K-ft----------ft or %-----------
    2     2     3       Y             -0.024            2.000
    3     2     4       Y             -0.024            2.000
    2     2     3       Y             -0.024            0.000
    1     1     2       Y             -0.146           10.000
    1     1     2       My            -0.146           10.000


=====================< Member Point Loads, BLC 2 >======================
          Joints
Member    I     J     Direction      Magnitude         Location
----------------------------------------K,K-ft----------ft or %-----------
    2     2     3       Y             -0.037            2.000
    3     2     4       Y             -0.037            2.000
    2     2     3       Y             -0.037            0.000
    1     1     2       My            -0.363           10.000
    1     1     2       Y             -0.363           10.000


==================< Member Distributed Loads, BLC 2 >===================
          Joints      Load Pattern        Pattern
Member    I     J       Label            Multiplier
------------------------------------------------------------------------
    2     2     3       BEMICE            1.0000
    3     2     4       BEMICE            1.0000
    1     1     2       COLICE            1.0000
```

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======================< Member Point Loads, BLC 3 >=====================
          Joints
Member    I    J    Direction      Magnitude        Location
-----------------------------------K,K-ft----------ft or %-----------
    1     1    2    X               0.039          10.000
    1     1    2    My             -0.039          10.000
    2     2    3    X               0.055           2.000
    2     2    3    X               0.055           0.000
    3     2    4    X               0.055           2.000
    2     2    3    Mz              0.055           2.000
    2     2    3    Mz              0.055           0.000
    3     2    4    Mz             -0.055           2.000

==================< Member Distributed Loads, BLC 3 >===================
          Joints         Load Pattern      Pattern
Member    I    J          Label           Multiplier
-----------------------------------------------------------------------
    1     1    2          COLWIND           1.0000

======================< Member Point Loads, BLC 4 >=====================
          Joints
Member    I    J    Direction      Magnitude        Location
-----------------------------------K,K-ft----------ft or %-----------
    2     2    3    Z              -0.012           2.000
    2     2    3    Z              -0.012           0.000
    3     2    4    Z              -0.012           2.000
    2     2    3    My              0.007           2.000
    2     2    3    My              0.007           0.000
    3     2    4    My              0.007           2.000
    1     1    2    Z              -0.039          10.000

==================< Member Distributed Loads, BLC 4 >===================
          Joints         Load Pattern      Pattern
Member    I    J          Label           Multiplier
-----------------------------------------------------------------------
    1     1    2          COLWNDZ           1.0000
    2     2    3          BEMWND1           1.0000
    3     2    4          BEMWND2           1.0000

======================< Member Point Loads, BLC 5 >=====================
          Joints
Member    I    J    Direction      Magnitude        Location
-----------------------------------K,K-ft----------ft or %-----------
    2     2    3    Y              -0.010           2.000
    2     2    3    Y              -0.010           0.000
    3     2    4    Y              -0.010           2.000
    2     2    3    X               0.006           2.000
    2     2    3    X               0.006           0.000
    3     2    4    X               0.006           2.000
    1     1    2    X               0.004          10.000
```

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Terminator Structure
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=====================< Member Point Loads, BLC 5 >=====================
          Joints
Member    I     J    Direction      Magnitude        Location
-------------------------------------K,K-ft----------ft or %-----------
    1     1     2    Y               -0.017           10.000
    1     1     2    My               0.017           10.000
    1     1     2    Mz               0.012           10.000


==================< Member Distributed Loads, BLC 5 >==================
          Joints       Load Pattern     Pattern
Member    I     J        Label        Multiplier
-----------------------------------------------------------------------
    1     1     2       COLNESX          1.0000
    1     1     2       COLNESC          1.0000
    2     2     3       BEMNESC          1.0000
    3     2     4       BEMNESC          1.0000


=====================< Member Point Loads, BLC 6 >=====================
          Joints
Member    I     J    Direction      Magnitude        Location
-------------------------------------K,K-ft----------ft or %------------
    2     2     3    Z                0.004            2.000
    2     2     3    Z                0.004            0.000
    3     2     4    Z               -0.004            2.000
    1     1     2    Y               -0.017           10.000
    1     1     2    Z               -0.022           10.000
    2     2     3    My              -0.002            2.000
    2     2     3    My              -0.002            0.000
    3     2     4    My              -0.002            2.000


==================< Member Distributed Loads, BLC 6 >==================
          Joints       Load Pattern     Pattern
Member    I     J        Label        Multiplier
-----------------------------------------------------------------------
    2     2     3       BM1NESZ          1.0000
    3     2     4       BM2NESZ          1.0000
    1     1     2       COLNESZ          1.0000
    1     1     2       COLNESC          1.0000
    2     2     3       BEMNESC          1.0000
    3     2     4       BEMNESC          1.0000


=====================< Member Point Loads, BLC 7 >=====================
          Joints
Member    I     J    Direction      Magnitude        Location
-------------------------------------K,K-ft----------ft or %--------------
    2     2     3    X                0.009            2.000
    2     2     3    X               -0.009            0.000
```

```
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                                              File: TERMSTND
        Terminator Structure
        John D. Engineer


        ============================< Load Patterns >============================
        Pattern              Magnitudes                      Locations
         Label    Dir       Start            End            Start          End
        ---------------------K/ft,F----------K/ft,F---------ft or %-------ft or %---
        BEMICE    Y         -0.024          -0.024          0.000          2.500
        COLICE    Y         -0.027          -0.027          0.000         13.250
        COLWIND   X          0.015           0.015          0.000         13.250
        COLWNDZ   Z         -0.018          -0.018          0.000         13.250
        BEMWND1   Z         -0.013          -0.013          0.000          2.500
        BEMWND2   Z         -0.013          -0.013          0.000          2.500
        COLNESX   X          0.004           0.004          0.000         13.250
        BM1NESZ   Z         -0.004          -0.004          0.000          2.500
        BM2NESZ   Z         -0.004          -0.004          0.000          2.500
        COLNESZ   Z         -0.005          -0.005          0.000         13.250
        COLNESC   Y         -0.007          -0.007          0.000         13.250
        BEMNESC   Y         -0.007          -0.007          0.000          2.500


        ==========================< Load Combinations >==========================
                                                                              RWPE
        No.   Description    BLC  Fac  BLC  Fac  BLC  Fac  BLC  Fac  BLC  Fac  SSdv
        -------------------------------------------------------------------------------
         1 DL + SC           Y    -1    1    1    7    1                         y
         2 DL + EXT ICE + SC L01  1    2    1                                    y
         3 DL + EX WNDX + SC L01  1    3    1                                    y
         4 DL + EX WNDZ + SC L01  1    4    1                                    y
         5 DL + NESC X  + SC L01  1    5    1                                    y
         6 DL + NESC Z  + SC L01  1    6    1                                    y
         7


        ========================< Envelope Displacements >========================
            +---------- Translation ---------+------------ Rotation -------------+
        Joint    X    lc    Y    lc    Z    lc    Rx    lc    Ry    lc    Rz    lc
        ----------in---------in---------in--------rad--------rad--------rad------
           1 U  0.000 3   0.000 1   0.000 5  0.00000 2  0.00000 4  0.00000 2
             L  0.000 2   0.000 2   0.000 4  0.00000 4  0.00000 5  0.00000 3
           2 U  0.136 3   0.000 1   0.115 2  0.00116 2  0.00351 4  0.00000 2
             L  0.000 2  -0.001 2  -0.426 4 -0.00374 4  0.00000 5 -0.00124 3
           3 U  0.136 3   0.037 3   0.115 2  0.00116 2  0.00349 4  0.00004 2
             L  0.000 2  -0.002 2  -0.321 4 -0.00374 4  0.00000 5 -0.00124 3
           4 U  0.136 3  -0.001 1   0.115 2  0.00116 2  0.00355 4 -0.00001 1
             L  0.000 2  -0.038 3  -0.532 4 -0.00374 4  0.00000 5 -0.00127 3
        ==========================< Envelope Reactions >==========================
            +------------- Forces ----------+------------ Moments -------------+
        Joint    X    lc    Y    lc    Z    lc    Mx    lc    My    lc    Mz    lc
        ---------K----------K----------K---------K-ft-------K-ft-------K-ft------
           1 U   0.00 2   1.62 2   0.38 4    3.16 4    0.00 5    4.06 3
             L  -0.40 3   0.67 1   0.00 5   -0.51 2   -0.02 4    0.00 2
        Tot: U   0.00 2   1.62 2   0.38 4
             L  -0.40 3   0.67 1   0.00 5
```

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======================< Envelope Section Forces >========================
Member            Shear       Shear                 Moment     Moment
    Sec     Axial  lc  y-y  lc   z-z   lc Torque lc  y-y  lc   z-z   lc
-------------K---------K----------K-------K-ft-------K-ft-------K-ft-----
  1 1 U     1.62 2    0.40 3    0.38 4    0.00 1    0.51 2    4.06 3
      L     0.67 1    0.00 1    0.00 1   -0.02 4   -3.16 4    0.00 2
    2 U     1.43 2    0.35 3    0.32 4    0.00 1    0.51 2    2.81 3
      L     0.57 1    0.00 1    0.00 1   -0.02 4   -2.01 4    0.00 2
    3 U     1.25 2    0.30 3    0.26 4    0.00 1    0.51 2    1.72 3
      L     0.48 1    0.00 1    0.00 1   -0.02 4   -1.05 4    0.00 2
    4 U     1.07 2    0.25 3    0.20 4    0.00 1    0.51 2    0.80 3
      L     0.39 1    0.00 1    0.00 1   -0.02 4   -0.29 4    0.00 2
    5 U     0.38 2    0.16 3    0.10 4    0.00 1    0.00 3    0.16 3
      L     0.15 1    0.00 1    0.00 1   -0.02 4    0.00 4    0.00 2
-------------------------------------------------------------------------
  2 1 U     0.11 3    0.22 2    0.00 1    0.00 1    0.05 4    0.24 2
      L     0.00 1    0.09 1   -0.06 4    0.00 1    0.00 1   -0.01 3
    2 U     0.06 3    0.13 2    0.00 1    0.00 1    0.03 4    0.15 2
      L     0.01 1    0.05 1   -0.04 4    0.00 1    0.00 1    0.00 3
    3 U     0.06 3    0.11 2    0.00 1    0.00 1    0.01 4    0.08 2
      L     0.01 1    0.04 1   -0.03 4    0.00 1    0.00 1   -0.03 3
    4 U     0.06 3    0.09 2    0.00 6    0.00 1    0.00 6    0.02 2
      L     0.01 1    0.03 1   -0.02 4    0.00 1    0.00 4   -0.05 3
    5 U     0.00 1    0.00 1    0.00 1    0.00 1    0.00 1    0.00 2
      L     0.00 1    0.00 1    0.00 1    0.00 1    0.00 1    0.00 1
-------------------------------------------------------------------------
  3 1 U     0.00 1    0.16 2    0.04 4    0.00 1    0.00 1    0.24 2
      L    -0.05 3    0.06 1    0.00 1    0.00 1   -0.07 4    0.10 1
    2 U     0.00 1    0.13 2    0.04 4    0.00 1    0.00 1    0.15 2
      L    -0.05 3    0.05 1    0.00 1    0.00 1   -0.05 4    0.06 1
    3 U     0.00 1    0.11 2    0.03 4    0.00 1    0.00 1    0.08 3
      L    -0.05 3    0.04 1    0.00 1    0.00 1   -0.03 4    0.03 1
    4 U     0.00 1    0.09 2    0.02 4    0.00 1    0.00 6    0.06 3
      L    -0.05 3    0.03 1    0.00 1    0.00 1   -0.01 4    0.01 1
    5 U     0.00 1    0.00 1    0.00 1    0.00 1    0.00 4    0.00 2
      L     0.00 1    0.00 1    0.00 1    0.00 1    0.00 1    0.00 5
-------------------------------------------------------------------------
====================< Envelope Section Deflections >=====================
        +--------- Translation ---------+        Defls as L/n Ratios
Memb Sec    x   lc   y   lc    z   lc  Rot x  lc  L/n(y) lc  L/n(z) lc
-------------in---------in---------in--------rad--------rad--------rad------
  1 1 U   0.000 1   0.000 1   0.000 1  0.00000 1     NC 1      NC 1
      L   0.000 1   0.000 1   0.000 1  0.00000 1     NC 1      NC 1
    2 U   0.000 1   0.000 1   0.008 2  0.00088 4     NC 1      NC 2
      L   0.000 2  -0.013 3  -0.042 4  0.00000 1     NC 3  3807.3 4
    3 U   0.000 1   0.000 1   0.031 2  0.00176 4     NC 1  5173.7 2
      L   0.000 2  -0.044 3  -0.144 4  0.00000 1  3603.9 3  1100.4 4
    4 U   0.000 1   0.000 2   0.069 2  0.00264 4     NC 2  2300.9 2
      L  -0.001 2  -0.087 3  -0.279 4  0.00000 1  1824.6 3   569.2 4
```

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=====================< Envelope Section Deflections >=====================
        +--------- Translation ---------+        Defls as L/n Ratios
Memb Sec     x    lc    y    lc    z    lc  Rot x  lc  L/n(y) lc  L/n(z) lc
-------------in---------in---------in--------rad--------rad--------rad------
     5 U   0.000 1   0.000 2   0.115 2  0.00351 4     NC 2  1377.5 2
       L  -0.001 2  -0.136 3  -0.426 4  0.00000 1  1171.6 3   373.1 4
       -----------------------------------------------------------------
     2 1 U   0.000 2   0.000 1   0.426 4  0.00374 4     NC 1   286.1 4
       L  -0.136 3  -0.001 2  -0.115 2 -0.00116 2     NC 2     NC 2
     2 U   0.000 2   0.009 3   0.400 4  0.00374 4  3238.5 3   381.8 4
       L  -0.136 3  -0.001 2  -0.115 2 -0.00116 2     NC 2     NC 2
     3 U   0.000 2   0.018 3   0.374 4  0.00374 4  1619.6 3   573.0 4
       L  -0.136 3  -0.001 2  -0.115 2 -0.00116 2     NC 2     NC 2
     4 U   0.000 2   0.028 3   0.347 4  0.00374 4  1079.0 3  1146.0 4
       L  -0.136 3  -0.001 2  -0.115 2 -0.00116 2     NC 2     NC 2
     5 U   0.000 2   0.037 3   0.321 4  0.00374 4   808.5 3     NC 4
       L  -0.136 3  -0.002 2  -0.115 2 -0.00116 2     NC 2     NC 2
       -----------------------------------------------------------------
     3 1 U   0.136 3   0.000 1   0.115 2  0.00116 2     NC 1     NC 2
       L   0.000 2  -0.001 2  -0.426 4 -0.00374 4     NC 2     NC 4
     2 U   0.136 3   0.000 1   0.115 2  0.00116 2     NC 1     NC 2
       L   0.000 2  -0.010 3  -0.453 4 -0.00374 4  3199.3 3  1134.4 4
     3 U   0.136 3   0.000 1   0.115 2  0.00116 2     NC 1     NC 2
       L   0.000 2  -0.019 3  -0.479 4 -0.00374 4  1591.9 3   566.0 4
     4 U   0.136 3  -0.001 1   0.115 2  0.00116 2     NC 1     NC 2
       L   0.000 2  -0.029 3  -0.506 4 -0.00374 4  1057.0 3   376.7 4
     5 U   0.136 3  -0.001 1   0.115 2  0.00116 2     NC 1     NC 2
       L   0.000 2  -0.038 3  -0.532 4 -0.00374 4   790.4 3   282.2 4
       -----------------------------------------------------------------


=====================< Envelope AISC Unity Checks >=====================
      Unity          Shear              Fb     Fb         Cm    Cm ASD
Memb   Chk Loc lc   Chk  Loc lc   Fa    yy     zz    Cb   yy    zz Eqn
------------------------------------Ksi----Ksi----Ksi----------------------
    1  0.229 1  4  0.015 3 z  4  3.52  27.00  21.60 1.00  0.85  0.60 H1-2
    2  0.013 1  2  0.013 1 y  2 18.91  26.26  23.46 1.00  0.60  0.85 H1-2
    3  0.016 1  4  0.010 1 y  2 18.91  26.26  23.46 1.00  0.85  0.85 H1-2
```

CHAPTER 8
FOUNDATIONS

8.1 GENERAL

Foundation design primarily depends on the in-place density and strength/strain properties of the soil on or in which foundations are located. The heterogeneous characteristics of soils or their localized variability make foundation design a much less exacting engineering problem than structural design or some facets of electrical design, but the inexactness of soil mechanics need not be a reason for ultraconservatism and costly foundations. Further, with the enhancements of convenient computer programs, tedious repetition of design practices for foundation design has been reduced. While this chapter is intended as a general guide, it cannot serve as a guarantee against foundation problems.

A thorough knowledge of geotechnical subsurface engineering parameters is essential to providing a reliable and cost-effective foundation design. Geotechnical engineering or soil analysis is beyond the scope of this document and generally requires the services of a geotechnical engineer to prepare site-specific recommendations. When designing foundations, it is important to address the following design issues:

- The allowable load-bearing capacity of the subsurface materials
- The allowable deformations permitted upon the structure/foundation under loading

In addition to site-specific borings and laboratory testing, additional data may be gathered pertinent to the site through reference to state or federal geologic mapping, aerial photos, Natural Resource Conservation Service (formerly the Soil Conservation Service) mapping, and other hydrological references. A number of federal and state agencies frequently have available information that can be consulted and will provide either regional or localized data to supplement a site subsurface investigation.

8.2 SOIL INFORMATION

8.2.1 General

A subsurface investigation should be conducted for each substation. Temporary installations and small distribution substations may only require a minimal amount of information. At these locations augered probe borings, in situ quasi-static cone penetrations (ASTM D3441), vane shear tests (ASTM D2573), or the pressure meter (ASTM D4719) can be used to provide an indication of the soil's engineering characteristics.

Soil probes or borings should be taken primarily at critical foundations. These normally are for line support structures (i.e., deadends) and transformers. The number of borings may vary from three at small substations to six or ten at larger substations. The depth of borings should be about 10 meters (30 feet) below the final grade of the substation yard, but may vary dependent upon:

1. Intensity of structural loads
2. Softness or wetness of subsurface soils
3. Depth of groundwater level

A sample specification for procurement of soil borings is included as an Appendix E to this chapter.

8.2.2 Soil Classification

Because of design considerations, the geotechnical engineer will typically determine whether to design the foundations as if the soil behaves as a cohesive (fine-grained clay-like) soil or as a granular or cohesionless (coarse-grained sand-like) soil. The description of the material noted on the soil boring log should be described in accordance with the Unified Soil Classification System (ASTM D2487 and D2488). (See Table 6-2 in Chapter 6.)

Material described as "sandy clay" can, for example, be assumed to behave predominately as cohesive material, whereas "clayey sand" will probably behave as granular material. The relative quantities of cohesive and granular materials can appreciably affect the soil properties and cause concern. Therefore, when in doubt, design the foundations both ways and use the most conservative design.

To assist with the visual classification of soil types, specific index classification tests can be performed. Typical index classification tests for cohesionless and cohesive soils are as follows:

Cohesionless
Grain Size Sieve Analysis   ASTM D422
Moisture Content   ASTM D2216
Specific Gravity   ASTM D854

Cohesive
Atterberg Limits   ASTM D4318
Moisture Content   ASTM D2216
Unit Weight   ASTM D2216
Specific Gravity   ASTM D854
Hydrometer   ASTM D422

Index tests provide data that can frequently be correlated with other engineering characteristics of the soils such as strength, swell potential, collapse potential, consolidation, and degree of compaction.

Although index tests should not be viewed as a total replacement to undisturbed engineering tests, they frequently can be used to supplement an investigation program and confirm either consistency or variability at site.

Specific references are available in research that relate index properties to engineering properties; these should be reviewed by an individual familiar with geotechnical engineering design who understands their limitations and appropriateness for use. Typically, it is not recommended to simply utilize presumptive engineering properties from tables or texts that rely on standard penetration tests, visual classifications, and limited index tests alone, particularly for cohesive soils where greater variability in strength and deformation may occur locally. Presumptive values for allowable bearing pressures on soil or rock should be used only as a means of guidance or for preliminary or temporary design. Further, the degree of disturbance to soil samples, whether standard penetration test samples or relatively undisturbed samples, have to be kept to a minimum prior to laboratory testing through the use of appropriate drilling, sampling, and transportation methods.

8.2.3 Bearing Values

Bearing values or engineering parameters developed from laboratory tests upon cohesive soils should be obtained from relatively undisturbed samples in accordance with "Practice for Thin-Walled Tube

Geotechnical Sampling of Soils," ASTM D1587, or "Practice for Ring-Lined Barrel Sampling of Soils," ASTM D3550.

Engineering parameters for granular soils can generally be estimated reliably by correlations with standard penetration blow counts. The parameter obtained is usually the internal friction angle (ϕ). Unconfined compressive strengths for cohesive or clay-like soils are best determined using "Test Method for Unconfined Compressive Strength of Soil" (ASTM D2166), although rough correlations relative to standard penetration tests have been developed.

In situ strengths derived from the quasi-static cone penetrometer (ASTM D3441), vane shear (ASTM D2573), or pressuremeter (ASTM D4719) are frequently more reliable, particularly in very soft soils, because of their minimization of sample disturbance and testing of the soils in place.

Rock coring to obtain sample recovery, Rock Quality Designation (RQD), and unconfined strengths may be required for sites with anticipated rock formations. It is also important to be familiar with local engineering characteristics of not only the individual rock formations present, but also their global or rock mass properties. Give special design consideration to swelling shales, steeply dipping rock, highly weathered or decomposed rock units, fractured or jointed rock, or clay or bentonite seamed rock units. These conditions may impact both the strength and deformation performance of structures founded in or upon rock.

8.2.4 Groundwater Level

The elevation of the groundwater level is important in foundation design for several reasons. Open-cut excavations below it within permeable stratas require dewatering and increased costs. The water level also has considerable influence on the bearing capacity and total settlement in granular soils. The bearing capacity of a spread footing in granular soil is derived from the density of the soil below the footing and the density of the soil surrounding the footing (backfill or surcharge). A rise of the water level above a depth greater than the width of the footing up to the top of the surcharge in effect reduces the effective overburden pressures within the sand to roughly half their original values, and further reduces the stiffness or strain carrying capacity of the granular soils. Therefore, the footing pressure that is expected to produce a 1-inch total settlement when the water level is at the surface is only about half that required to produce a 1-inch total settlement when the water level is at or below a depth equal to the footing width below the base of the footing.

The effect of the water level is to reduce the effective overburden pressure or density of the granular soil because of buoyancy. The submerged density of granular soil is about half of the moist or dry density. If the water level is at or exceeds a depth equal to the footing width below the base of the footing, the bearing capacity is not affected. If the water level is at the bottom of the footing or may rise to the ground surface, the portion of bearing capacity obtained by the density of soil below the footing is reduced in half. If the water level is at the top of the backfill, the portion of bearing capacity obtained by the density of the surcharge is also reduced in half.

8.2.5 Differential Settlement

Minor differential settlement between foundations in substations is generally acceptable. However, there are certain soils and conditions that have to be carefully reviewed and avoided if possible. Silts and silty sands are usually problem soils, both from strength relationships and degree of compaction. Carefully examine weak strata of soil under a thin layer of dense or good soil and take them into consideration regarding settlement. Organic or swamp-like soils, or uncompacted fills, pose a risk to differential long-

term settlement to structures. Soils that may expand, collapse, or disperse upon wetting require special attention for design by a geotechnical engineer.

8.2.6 Chemical Tests

Soils may impact foundations and other buried systems as a result of chemical attack on concrete, corrosion of steel, and other detrimental weathering. Consult a corrosion specialist or engineer familiar with these chemical tests to determine the appropriate cement type based on prevailing soluable sulfate and chloride ion concentrations within the soil or groundwater. Resistivity of the soil, pH, sulfides, Redox readings, and nitrates may also have detrimental effects on concrete, steel, or grounded structures. These conditions require localized testing and design.

8.2.7 Seismic Evaluation

Seismic evaluation of substation sites is currently beyond the scope of this document, but should be reviewed locally by a geotechnical engineer, and geologist, where required. Delineating the location of faults and surface disruptions, and the potential for sand boils, soil flows, slope slides, and liquefiable soils, is essential to designing foundations that remain stable under extreme seismic events. If liquefaction is determined to be likely at a site under certain seismic events, then design of the foundations to extend beyond such zones or mitigation measures to improve the soils will need to be pursued in final design. Hand calculation techniques or commercially available computer programs performed by a geotechnical engineer can evaluate liquefaction potential, based on probable earthquake criteria.

8.3 FOUNDATION TYPES

The various types of foundations for substation structures and equipment include drilled shafts (augered piers), spread footings, piles, slabs on grade, rock anchors, and direct embedment for wood or concrete poles.

8.3.1 Drilled Shafts (Piers)

The drilled shaft is constructed by augering, drilling, or coring a hole in the ground, placing reinforcing steel, and filling with concrete. The anchor bolts may be cast in the shaft at this time or set in a cap constructed at some later time. Drilled shaft construction and design has been developed and researched by the Association of Drilled Shaft Contractors (ADSC) and the American Concrete Institute (ACI), each of which has developed typical standard specifications for their construction. Further, design and construction procedures are documented through extensive research on behalf of the Federal Highway Administration (FHWA), U.S. Department of Transportation, in the *Drilled Shaft Manual* (Publication No. FHWA Implementation Package 77-21) and *Drilled Shafts* (Publication No. FHWA-HI-88-042).

When there is a sufficient quantity of foundations, the drilled shaft foundations are usually more economical than other types because of the "assembly line" installation procedure. Drilled shafts are most economical when soil conditions are not wet and sandy, although, with care and quality control oversight during construction, casings, bentonite slurries, and polymer muds are currently available to promote their construction.

If wet and sandy soil is below a level where a spread footing would bear, the spread footing should be evaluated and may be selected. However, if wet and sandy conditions also exist above the spread footing level, consider the drilled shaft, allowing extra costs for encasement. This design may be more

economical than attempting to install a spread foundation in wet, sandy soil, requiring either dewatering to stabilize the excavation or pumped concrete below water.

Drilled shafts are best suited to resist overturning shears and moments. Uplift and compressive forces are also adequately resisted by drilled shafts. Where soils permit belling of the shaft, additional uplift or compressive capacity is often gained economically.

Common sizes for substation foundations range from 0.61 meter (24 inches) to l.52 meters (60 inches) in diameter, in 150-mm (6-inch) increments. Drilled shafts above 2.13 meters (84 inches) in diameter are typically installed in 300-mm (12-inch) increments with a maximum diameter of 3.05 meters (120 inches) available for extreme substation applications.

The engineer should attempt to utilize the same shaft diameter for as many foundations as practical. Belling of the shaft is less frequently performed for substation foundations, but has cost advantages when permissible.

For most substation equipment support structures and line support structures, the foundations are required to resist moderate shear forces and overturning moments. For A-frame and lattice-type line support structures, shear, uplift, and compression are typical design loads. Drilled shafts also provide improved performance against differential settlement for critical transformer structures and have been used to provide support against overturning loads resulting from wind or seismic design conditions.

8.3.2 Drilled Shaft Design

Drilled shaft foundations derive their support to carry loads based on the shaft's shape (straight versus belled), soil/rock stratification, groundwater level, and applied loads. Generally, compressive loads are carried by a combination of skin friction along the shaft's perimeter and end bearing at the base. In cases where shafts bear upon or in rock, the overlying soil skin friction is typically discounted for design. Uplift loads are carried as skin friction alone for straight shafts. Shafts with bells require special review as to their capacity and the load transference mechanism based upon soil strata types and depth-to-diameter ratios of shaft and bell embedment. Lateral loads (shear and/or moment) are carried by the lateral resistance of soil/rock against the shaft's cross section.

The spacing of shafts for adjacent structures, commonly referred to as group action, should be evaluated to prevent or minimize stress overlap from skin friction or lateral stresses. A common rule of thumb is to maintain a minimum shaft spacing (centerline to centerline) of not less than three times the diameter, although selected research has indicated that some soil types may require a greater shaft spacing. Typically, compression and uplift loads are designed separate from lateral design analyses. Conventional factors of safety are applied to compression and uplift soil resistance to account for potential variability of subsurface conditions. Depending on the method of lateral load analysis used for design, the lateral design may or may not use factors of safety. Methods employed that evaluate shaft deflection and rotation performance typically do not use factors of safety since they are determining the predicted load/deformation characteristics of the drilled shafts under the design loading.

Specific techniques for design of shafts have been documented quite thoroughly by others. One useful source in performing final design is IEEE Std. 691, "IEEE Trial-Use Guide for Transmission Structure Foundation Design," which was jointly authored by the Institute of Electrical and Electronics Engineers and the American Society of Civil Engineers (ASCE).

For purposes of lateral design of drilled shaft foundations, several techniques exist to evaluate shaft performance. With the advent of computers and the ability to evaluate multiple length and diameter shaft combinations readily, lateral analysis of shafts has been performed by methods employing computer stress/strain relationships rather than the older rough calculations by hand using ultimate strength of a passive pressure wedge.

The design of drilled shafts for lateral loads should account for the effects of soil/rock–structure interaction between shaft and subsurface stratas to account for deflection and rotation of the shafts. Final design methods employing this conventional process are described under Method A presented below. In 1995 the Rural Utilities Service generated a Design Guide, RUS Bulletin 1724E-205, "Embedment Depths for Concrete and Steel Poles," for preliminary selection of embedment depths for concrete and steel poles. Selected literature from this document is referenced in RUS Bulletin 1724E-205 is briefly described under Method B presented below. Previous procedures identified in the 1978 predecessor edition of this manual are again provided and described under Method C. It is recommended that the Method C procedures for evaluating the ultimate capacity and deflection, based on hand calculation procedures (e.g., Czerniak 1957; Broms 1964) be used primarily for preliminary design or cost estimating purposes. Along with the earlier mentioned FHWA publications and IEEE Std. 691, government agencies including the American Association of State Highway and Transportation Officials require computer-modeled finite difference procedures like those described in Method A.

8.3.2.1 Method A—Lateral Drilled Shaft Design (Computer-Modeled Soil Interaction Curves):

Drilled shaft response is dependent upon the applied load, the soil/rock stratigraphy (including groundwater level), and the dimensional and physical features of the drilled shaft. Under applied load, soil–structure interaction behaves in either a linear-elastic, elastic-plastic, or ultimate-plastic state, depending on the soil subgrade modulus. The resulting load-displacement relationship has been described by Reese and O'Neill in FHWA publications as nonlinear subgrade modulus P-Y curves. A similar design/analysis model has been prepared and developed by EPRI (Project RP-1280-1).

The use of P-Y curves describing the relationship between lateral pressure P and lateral displacement Y at individual stations along the length of the shaft permits the computer program to solve for deflected shapes of the shaft, as developed for the specific stratigraphic soils present. It is possible to assign rock fixity with Reese's program at any point along the shaft and to account for additional rotational restraints, such as grade beams or slab inter-ties.

Output from the computer analysis includes deflections, rotations, internal moments, internal shears, and soil reactions along the entire shaft length. Moments and shears generated by the program are used by structural engineers to design the amount and spacing of longitudinal and tie steel. The program further permits evaluation of shaft performance under the cracked section analysis, resulting in a more accurate representation of shaft and structure movement under load.

Reese's fundamental theoretical principles were documented in 1977 and 1988. The computer program (COM624) was originally developed for the FHWA and is currently available through the Center for Microcomputers in Transportation, McTRANS Center, as sponsored by the University of Florida at Gainesville. Other comparable commercial versions of this public domain program are also available for purchase.

8.3.2.2 Method B—Lateral Shaft Resistance Design (RUS-Hansen Approach):

With the increasing use of both concrete and steel (light-duty) poles as replacements for wood poles in selected instances, RUS documented a method of evaluating pole embedment using an earlier referenced approach prepared by Hansen in 1961 for stratified soils.

The design analogies applied to direct-embedded poles can be further extended through Hansen's methodology to drilled shafts installed in stratified soils. As noted in RUS Bulletin 1724E-205, "The engineering information in this bulletin is for use in preliminary selection of embedment depths for steel and concrete transmission poles sustaining relatively large overturning moments." Bulletin 1724E-205 further notes the limitations of this method due to the proposed national scope of use and variations in localized performance.

RUS Bulletin 1724E-205 describes comparisons performed between the methods of Hansen (1961), Broms (1964), RUS Bulletin 1724E-200, "Design Manual for High Voltage Transmission Lines." Davisson and Prakash (1963), and Naik and Peyrot (1980).

Drilled shafts designed previously by the Broms method for line support structures (as further described in Method C from the 1978 REA *Design Guide for Rural Substations*) may be alternatively designed for stratified soils with the Hansen method outlined in RUS Bulletin 1724E-205, "Embedment Depths for Concrete and Steel Poles."

8.3.2.3 Method C—Lateral Drilled Shaft Design (Equipment Support Structures) [Reprinted from 1978 RUS Manual]:
Equipment support structures designed by the working stress method having overturning moments at the column bases may be easily designed by a method developed by E. Czerniak and published in the *Journal of the Structural Division of the Proceedings of the American Society of Civil Engineers* in March 1957.

Convenient nomographs and soil values make the tedious formulas unnecessary. Some formulas are presented here for purposes of illustration and as an aid in design.

Equation 8-1

$$L^3 - 14.14 \frac{H_o L}{R} - 18.85 \frac{M_o}{R} = O \ for \ round \ piers$$

Where:
- L = Embedment length in meters (feet)
- H_o = Lateral force per meter (foot) of pier diameter, in N/m (lbs/ft)
- M_o = Moment per meter (foot) of pier diameter, applied at the resisting surface, in m-N/m (ft-lbs/ft)
- R = Allowable lateral soil resistance, in newtons per square meter per meter of depth (pounds per square foot per foot of depth)

Lateral soil pressure (R) values for design are given in Table 8-1.

The maximum bending moment in the shaft is obtained from Equation 8-2:

Equation 8-2

$$M_{MAX} = C_M H_o L D$$

Where:
- D = Shaft diameter, in meters (feet)
- C_M = Moment coefficient

Table 8-1: Recommended Lateral Soil Pressure (R).
Ref. E. Czerniak, *Journal of the Structural Division of the Proceedings of the American Society of Civil Engineers*, March 1957. Reproduced with permission of the American Society of Civil Engineers.

Material	Value	
	PSF/FT	N/m^2/m
Rock in Natural Beds – Limited by the Stress in the Pier		
Medium Hard Caliche	500	78,500
Fine Caliche with Sand Layers	400	62,800
Compact Well-Graded Gravel	400	62,800
Hard Dense Clay	400	62,800
Compact Coarse Sand	350	55,000
Compact Coarse and Fine Sand	300	47,100
Medium Stiff Clay	300	47,100
Compact Fine Sand	250	39,300
Ordinary Silt	200	31,400
Sandy Clay	200	31,400
Adobe	200	31,400
Compact Inorganic Sand and Silt Mixtures	200	31,400
Soft Clay	100	15,700
Loose Organic Sand and Silt Mixtures and Muck or Bay Mud	0	0

(Newtons per Square Meter per Meter Depth)
(Pounds per Square Foot per Foot Depth)

C_M, the moment coefficient, can be calculated from Equation 8-3 and Figure 8-1, or the maximum value can be obtained from Table 8-2.

Equation 8-3

$$C_M = \left(\frac{E}{L} + \frac{X}{L}\right) - \left(\frac{4E}{L} + 3\right)\left(\frac{X}{L}\right)^3 + \left(\frac{3E}{L} + 2\right)\left(\frac{X}{L}\right)^4$$

Where:

$$E = \frac{M_o}{H_o}$$

X = Distance from supporting surface to point of maximum bending moment (for the force diagram shown X = 0.35 L ±)

Table 8-2: Moment Coefficients

E/L	0	0.25	0.5	0.75	1.0	1.25	1.5	1.75	2.0
C_M	0.26	0.48	0.70	0.92	1.16	1.40	1.64	1.88	2.12

A drilled shaft foundation design example is illustrated in Figure 8-2 for a bus support structure.

H_t = 2.27 kN
M_t = 12.42 kNm
assume   R = 39.3 kN/m^2/m
            D = 0.61 m

FORCE DIAGRAM   MOMENT DIAGRAM
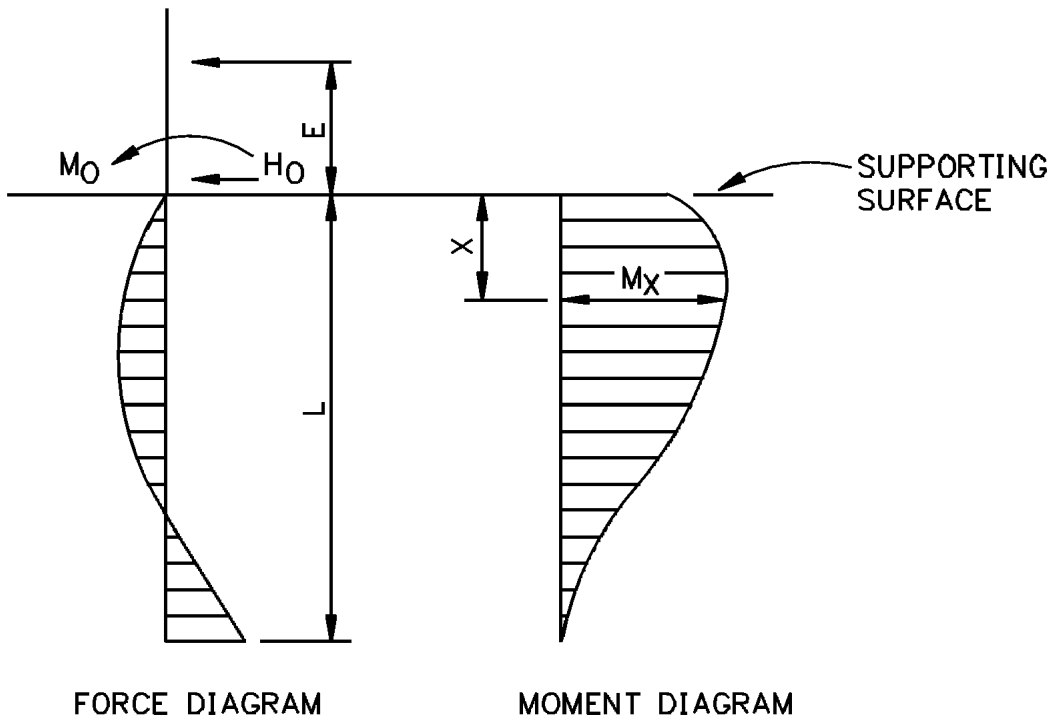
Figure 8-1: Drilled Shaft Force and Moment Diagrams
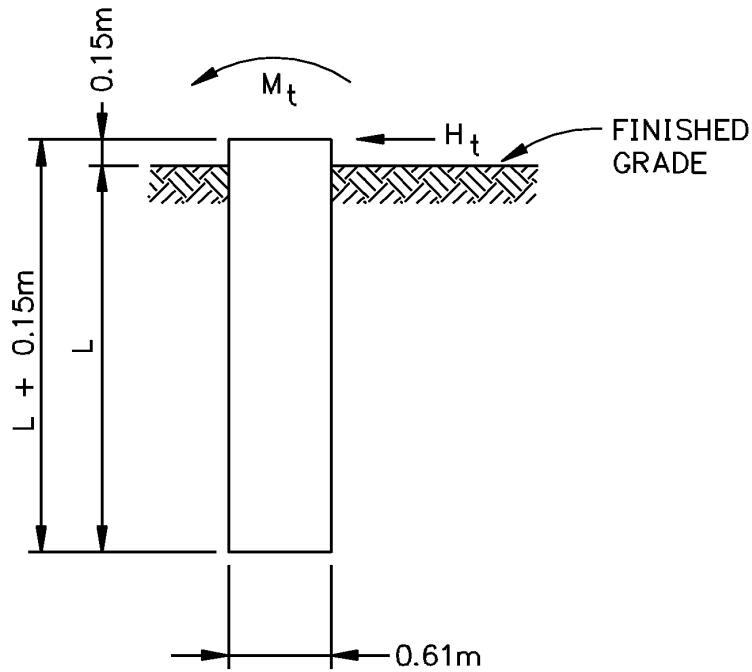
Figure 8-2: Drilled Shaft Elevation—Example

$$M_o = \frac{M_t}{D} = \frac{12.42\ kNm + .15\ m\ (2.27\ kN)}{.61\ m} = \frac{20.92\ kNm}{m}$$

$$H_o = \frac{H_t}{D} = \frac{2.27\ kN}{.61\ m} = 3.72\ \frac{kN}{m}$$

$$E = \frac{20.92}{3.72} = 5.62\ m$$

$$L^3 - 14.14\ \frac{H_o L}{R} - 18.85\ \frac{M_o}{R} = 0$$

$$L^3 - 14.14\ \frac{(3.72)L}{39.3} - 18.85\ \frac{(20.92)}{39.3} = 0$$

$$L = 2.37\ \text{meters; say 2.4 meters}$$

$$\frac{E}{L} = \frac{5.62}{2.4} = 2.3$$

$$\text{interpolating}\ C_M = \frac{30}{25}\ (0.24) + 2.12 = 2.41$$

$$M_{max} = C_M\ H_o LD = 2.41\ (3.72)2.4(0.61) = 13.1\ kNm$$

For this foundation use six 15.9 mm ϕ bars at equal spacing for reinforcement; see Tables 8-3 through 8-6. Use 9.55 mm ϕ bars for ties.

Table 8-3: Maximum Moment in kN-m for Augered Piers with 6 Straight Bars

Diameter of Augered Pier	6-15.9mm	6-19.1mm	6-22.2mm	6-25.4mm
30.5cm Φ	7.8	11.1	15.0	19.9
45.7cm Φ	14.6	20.7	28.2	37.1
61.0cm Φ	21.4	30.3	41.4	54.4
76.2cm Φ	28.1	39.9	54.5	71.7
91.4cm Φ	34.8	49.5	67.5	88.9
106.7cm Φ	41.6	59.1	80.7	106.2
121.9cm Φ	48.4	68.7	93.8	123.5
(Fy = 27.6 kNcm^2, f$_C$' = 2060 N/cm^2 (Based upon simplified working stress assumptions)				

Table 8-4: Maximum Moment in kN-m for Augered Piers with 8 Straight Bars

Diameter of Augered Pier	8-15.9mm	8-19.1mm	8-22.2mm	8-25.4mm
30.5cm Φ	11.4	16.3	22.1	29.2
45.7cm Φ	21.3	30.2	41.2	54.2
61.0cm Φ	31.0	44.2	60.2	79.3
76.2cm Φ	40.9	58.0	79.2	104.3
91.4cm Φ	50.7	72.0	98.2	129.3
106.7cm Φ	60.6	86.0	117.3	154.4
121.9cm Φ	70.4	99.9	136.3	179.4
(Fy = 27.6 kN/cm^2, f$_C$' = 2060 N/cm^2) (Based upon simplified working stress assumptions)				

Table 8-5: Maximum Moment in Ft-KIPS for Augered Piers with 6 Straight Bars

Diameter of Augered Pier	6 - #5	6 - #6	6 - #7	6 - #8
12" Φ	5.75	8.2	11.1	14.7
18" Φ	10.8	15.3	20.8	27.4
24" Φ	15.8	22.4	30.5	40.1
30" Φ	20.7	29.4	40.2	52.9
36" Φ	25.7	36.5	49.8	65.6
42" Φ	30.7	43.6	59.5	78.3
48" Φ	35.7	50.7	69.2	91.1
(Fy = 40 KSI, f$_C$' = 3000 PSI) (Based upon simplified working stress assumptions)				

Table 8-6: Maximum Moment in Ft-KIPS for Augered Piers with 8 Straight Bars

Diameter of Augered Pier	8 - #5	8 - #6	8 - #7	8 - #8
12" Φ	8.4	12.0	16.3	21.5
18" Φ	15.7	22.3	30.4	40.0
24" Φ	22.9	32.6	44.4	58.5
30" Φ	30.2	42.8	58.4	76.9
36" Φ	37.4	53.1	72.4	95.4
42" Φ	44.7	63.4	86.5	113.9
48" Φ	51.9	73.7	100.5	132.3
(Fy = 40 KSI, f$_C$' = 3000 PSI) (Based upon simplified working stress assumptions)				

8.3.3 Drilled Shaft Design (Line Support Structure)

For pole-type line support structure foundations, a different method of foundation design is employed. These structures are designed on the basis of yield stress, and appropriate overload factors are applied to the structure loads. To complement these loadings, a foundation design is used utilizing the ultimate strength of the soil. A very satisfactory method is illustrated, developed by Teng and Associates and based on the theory presented by B.B. Broms in the *Journal of the Soil Mechanics and Foundation Division of the Proceedings of ASCE* (March 1964 and May 1964).
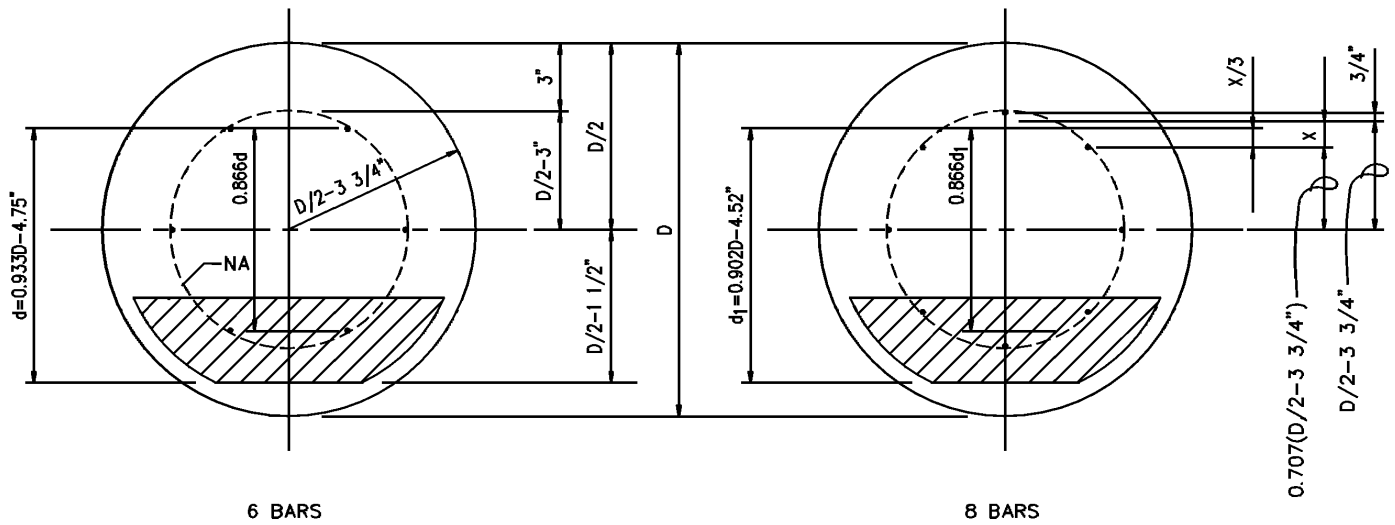
Figure 8-3: Drilled Shaft Section

Some of this information is presented here as an aid in design:

k_p = Coefficient of passive earth pressure
 = $Tan^2(45 + \phi/2)$
ϕ = Angle of internal friction of soil $\cong 28.5° + N/4$
γ = Effective unit weight of soil, in kg/m^3 (pcf)
c = Cohesive strength of soil, ½ unconfined compressive strength (qu), in N/m^2 (psf)
N = Number of blows per foot from standard penetration test
H = M/Q
qu = Unconfined compressive strength $\cong N/4$

q = $\dfrac{Q}{9cD}$

For a drilled shaft foundation in cohesive soil use Equations 8-4 and 8-5:

Equation 8-4

$$L = 1.5D + q\left[1 + \sqrt{2 + (4H + 6D)/q}\,\right]$$

Equation 8-5

$$M_{max} = M + 1.5\,QD + \frac{Q^2}{18cD} \text{ @ } 1.5D + q \text{ below top of foundation}$$
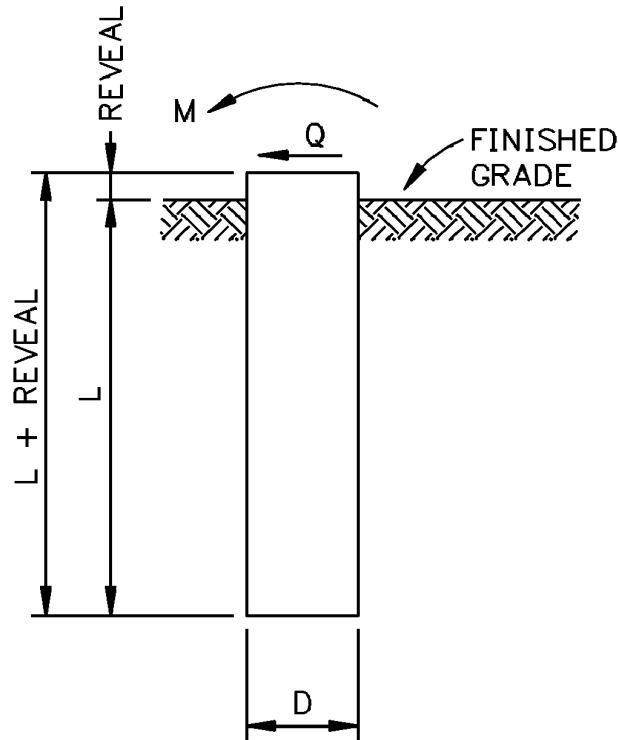
Figure 8-4: Drilled Shaft Elevation—General

For a drilled shaft foundation in granular soil, use Equations 8-6, 8-7, 8-8, and 8-9:

Equation 8-6

$$L^3 - \frac{200\,QL}{k_p g D} - \frac{200M}{k_p g D} = 0 \quad (Metric)$$

Equation 8-7

$$L^3 - \frac{2\,QL}{k_p g D} - \frac{2M}{k_p g D} = 0 \quad (English)$$

Equation 8-8

$$M_{max\ bending} = M + \frac{0.545Q\sqrt{Q}}{\sqrt{0.010 k_p \gamma D}} \quad @ \quad 0.817\sqrt{\frac{Q_{belowgrade}}{0.010 k_p \gamma D}} \ (Metric)$$

Equation 8-9

$$M_{max\ bending} = M + \frac{0.545Q\sqrt{Q}}{\sqrt{k_p \gamma D}} \quad @ \quad 0.817\sqrt{\frac{Q_{belowgrade}}{k_p \gamma D}} \ (English)$$

Utilize standard design procedures for determining the required area of reinforcing steel.

A foundation design using Brom's Theory for granular soil is illustrated below:

8.3.3.1 Design Example 8-1

Given:
 Q = 47.6 kN
 M = 535 kNm
 γ = 1762 kg/m^3
 ϕ = 28.5 + 26/4 = 35°
 D = 1.22 m
 N = 26 blows/.3048 m

$$k_p = \tan^2 \left(45° + 35°/2\right) = 3.69$$

$$L^3 - \frac{200(47.6)L}{3.69\,(1762)1.22} - \frac{200(535 + 0.15\,(47.6))}{3.69\,(1762)1.22} = 0$$

L = 2.56 m + 0.15 m for reveal

L = 2.7 m

$$M_{max\ bending} = 535 + 0.15(47.6) + \frac{0.545(47.6)\sqrt{47.6}}{\sqrt{0.010(3.69)1762\,(1.22)}} = 562 \text{ kNm}$$

$$@\ _{0.817} \sqrt{\frac{47.6}{0.010(3.69)1762(1.22)}} = 0.63 \text{ m below grade}$$

8.3.4 Compression and Uplift Capacity (Drilled Shafts)

When designing drilled shaft foundations for loads that consist of compression or uplift, the type of soil (cohesive or granular) will govern the design philosophy employed.

As referenced in IEEE Std. 691, drilled shaft resistance is typically derived from the strength relationship of the cohesive or granular soil stratigraphy. Further, the depth of water will impact these design capacities.

8.3.4.1 Compression Capacity: Axial compressive loads applied to a drilled shaft are resisted by both skin friction and end bearing. Initially, as loads are applied, they are generally transferred as skin friction to the soil with increasing depth, and then redistributed from the top of the shaft down as loads increase. With increased axial compressive loads, the relative percentage of load carried at the base as end bearing increases. This load transfer mechanism is impacted by such factors as type of soil, depth of strata along shaft, base support material, water level, in situ stresses, construction methods employed, and relative size and shape of the shaft.

An extensive amount of research has been performed on drilled shafts utilizing full-scale load tests to analyze the soil/structure interaction. Although numerous approaches have been documented, the generally accepted procedure for straight shafts in cohesive soils is described as the "Alpha" method and in cohesionless soils as the "K$_O$" method.

8.3.4.1.1 Cohesive (Undrained) Soil ("Alpha" Method)

Equation 8-10

$$Q_T = Q_{SF} + Q_{EB}$$

Equation 8-11

$$Q_{SF} = pD \sum_{i=0}^{H} \frac{acL_i}{F.S.}$$

Equation 8-12

$$Q_{EB} = \frac{pD_B^2}{4} \frac{N_c c}{F.S.}$$

Where:

D	=	Diameter of shaft, in m (ft)
D_B	=	Diameter of shaft base, in m (ft)
á	=	Alpha, shear strength reduction factor
c	=	Cohesion, undrained shear strength (½ unconfined compressive strength), in N/m^2 (psf)
L_i	=	Increments of shaft in different stratas, in m (ft)
H	=	Total length of shaft, in m (ft)
N_c	=	Bearing capacity factor for deep foundations
F.S.	=	Factor of safety

For drilled shaft foundations where the depth-to-diameter ratio exceeds approximately 4.0, the value for N_c for deep foundations may be assumed as equal to 9.0 according to Adams and Radhakrishna (1975); Meyerhof (1951); and Woodward, Gardner, and Greer (1972). At depth-to-diameter ratios less than 4.0, the N_c factor has to be adjusted toward shallow foundation design in accordance with Vesic, but will not be less than 5.14 according to Terzaghi (1943).

The Alpha factor has been developed from numerous studies by researchers and is generally considered to be similar to Figure 8-5 for drilled shafts by Kulhawy and Jackson (dependent upon shear strength).

Because of the variability of soils, even with a comprehensive subsurface investigation, a factor of safety in compression of 2.0 to 3.0 is typically used for cohesive soils. A higher factor of safety in cohesive soils is justified to recognize the more long-term tendency of cohesive soils to experience settlement.

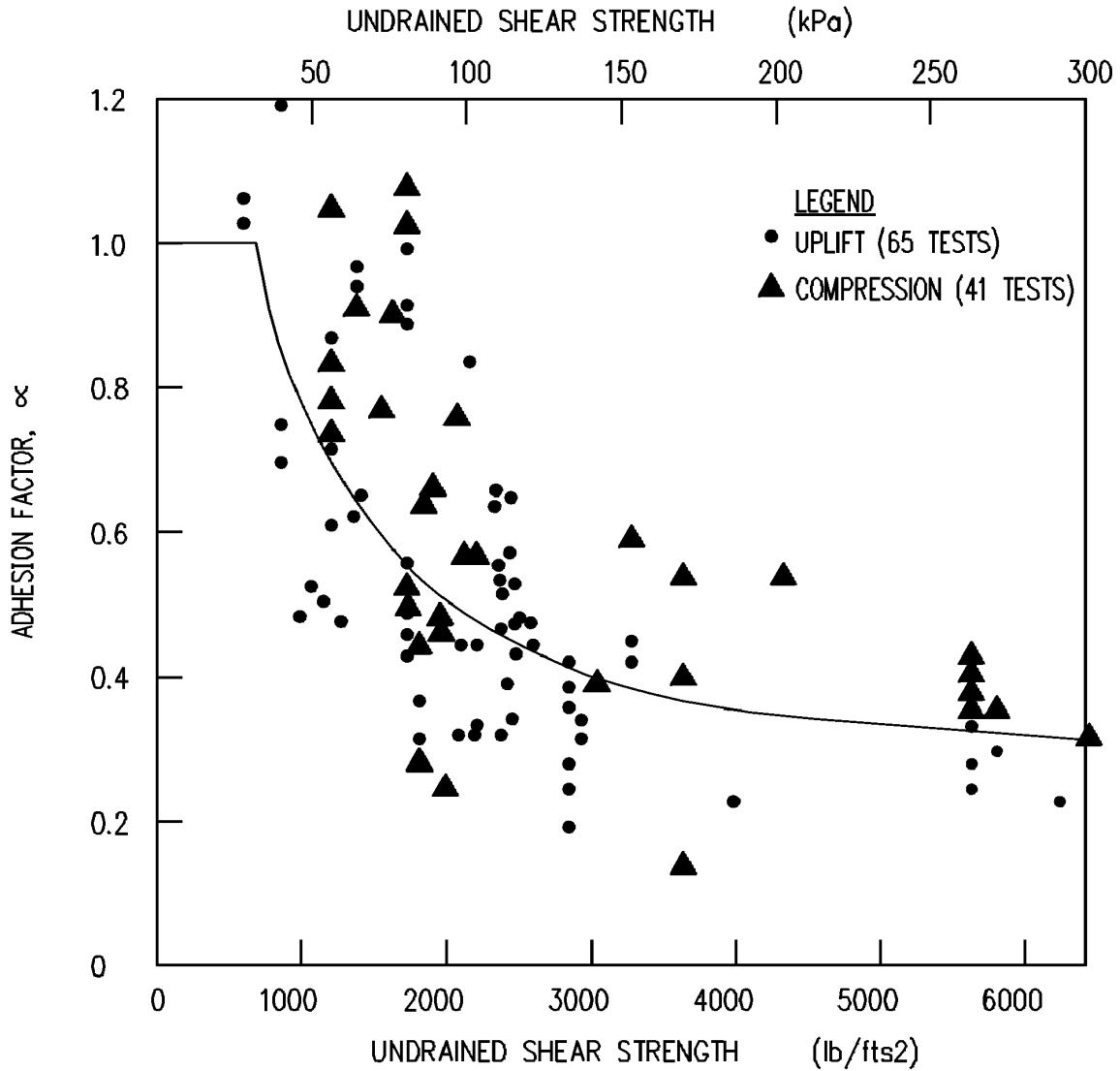Figure 8-5: á Function for Drilled Shafts. Ref. Kulhawy and Jackson. ASCE 1989.
Reproduced with permission of the American Society of Civil Engineers.

8.3.4.1.2   Cohesionless (Drained) Soil (K_O Method)

Equation 8-13

$$Q_T = Q_{SF} + Q_{EB}$$

Equation 8-14

$$Q_{SF} = \pi D \sum_{i=0}^{H} \frac{K_o \, \overline{\sigma}_v (\tan \phi)}{F.S.}$$

Equation 8-15

$$Q_{EB} = \frac{\pi D_B^2}{4} \frac{\gamma H N_q}{\gamma}$$

Where:

D	=	Diameter of shaft, in m (ft)
D_B	=	Diameter of shaft base, in m (ft)
K_o	=	Coefficient of lateral earth pressure (generally between active and at-rest states and dependent upon shaft installation method and soil in situ density)
ã	=	Effective unit weight of soil, in kg/m^3 (pcf)
$ó_v$	=	Effective vertical pressure at point of interest in N/m^2 (psf)
ϕ	=	Friction angle shaft/soil interaction (generally not in excess of angle of internal friction of soil strata)
H	=	Total length of shaft, in meters (feet)
N_q	=	Bearing capacity factor for deep foundations
F.S.	=	Factor of safety

The effective vertical stress in cohesionless soils for both the skin friction calculation and end bearing components are typically limited to their "critical depth." based on research performed by Vesic. The critical depth factor depends on soil density and generally varies between 10 to 20 times the shaft diameter. In theory, the crushing of sand grain particles and the resulting failure to achieve higher skin friction and end-bearing components occurs at depths where the shaft length exceeds these critical depth factors, and therefore the maximum effective stress has to be limited in the calculations.

Due to the relatively deep depth of drilled shafts, the bearing capacity factor N_q is generally discounted in the equation for end bearing and the relatively small percentage of overall capacity.

Consider total shaft settlement due to axial compressive loads. Settlement depends on the elastic shortening of the shaft and soil characteristics. Consolidation from uncompacted fills, landfills, organic layers, or collapsible or dispersive soils may result in unacceptable settlement or long-term negative skin-friction (down drag) of shafts. Rock formations should be evaluated to determine the mass formation properties such as weathering, joints and fractures, and clay filled cracks.

Belled shafts are frequently used where local soil conditions permit short-term stability of the bell. Where soils permit belled construction, typically cohesive soils and some shales, and total settlement is not anticipated to be excessive under higher loading, the base diameter may be used when determining the end bearing capacity. Typically, the length of the shaft occupied by the bell is discounted when determining the skin friction component.

A factor of safety in compression of 2.0 is typically used for cohesionless soils.

8.3.4.2 Uplift Capacity

8.3.4.2.1 Cohesive (Undrained) Soil: Axial uplift capacity of straight shafts is derived from the skin friction or adhesion component of the shaft compressive capacity calculated in Equation 8-13. In addition, the effective dead weight of the shaft may be added (unfactored) to the resistance to uplift. This effective weight consists of the total weight of the shaft above the ground water level and the buoyant weight of the shaft below.

Dependent upon the shaft depth-to-diameter ratio, and whether the shaft is belled, other failure surface concepts have been developed. For relatively shallow shafts or belled shafts, the methodology introduced by Meyerhof and Adams is recommended. This approach considers the shaft base to perform as an inverse bearing capacity failure without skin friction support, as either a cone-shaped or curved surface failure mode.

The factor of safety in uplift of 1.5 is typically used for cohesive soils.

8.3.4.2.2 <u>Cohesionless (Drained) Soil</u>: Axial uplift capacity of straight shafts is derived from the skin friction component of the shaft compressive capacity calculated in Equation 8-14.

An alternative method by Meyerhof and Adams for cylindrical shear has been proposed for comparable shaft design. However, the construction of belled shafts within a cohesionless soil is impractical and minimizes the likelihood of this approach, except for shafts that are backfilled entirely after an open excavation.

A factor of safety in uplift of 1.5 is typically used for cohesionless soils. The effective weight of the shafts (total above the groundwater level and buoyant below) may be added as an unfactored component.

8.3.5 Spread Footings

8.3.5.1   General: Spread footings comprised of a vertical pier or wall seated on a square or rectangular slab located at some depth below grade have long been used in substation design.

They are usually preferred for transformers, breakers, and other electrical equipment. They are economical where only a small quantity of foundations is required. They are reliable and easy to design.

The installation time and costs for spread footings are more than for augered piers because of the excavation, forming, form stripping, backfilling, and compacting.

Compaction of backfill around spread footings should at least be equal to that of the undisturbed soil before the footing was installed.

Spread footings should always be seated at a depth below the average frost penetration of the area. See Figure 8-6.

CAUTION: The engineer should determine if the average frost depth will be sufficient for the prevailing conditions. Deeper footings may be warranted.

8.3.5.2   Design for Compression: In designing a spread footing for only downward loads, divide the total net load by the allowable soil-bearing capacity and obtain the area of the footing required.
CAUTION: In granular soils the water table location may have significant effect on the allowable soil capacity.

Equation 8-16

$$A = \frac{\text{Total Net Load}}{P}$$

Where:

A	=	Area of footing base, in m^2 (sf)
Total Net Load	=	LL + DL – Wt of displaced soil
LL	=	Maximum weight or force exerted on footing by equipment or structure
DL	=	Weight of foundation
P	=	Allowable soil bearing pressure, in kg/m^2 (psf)
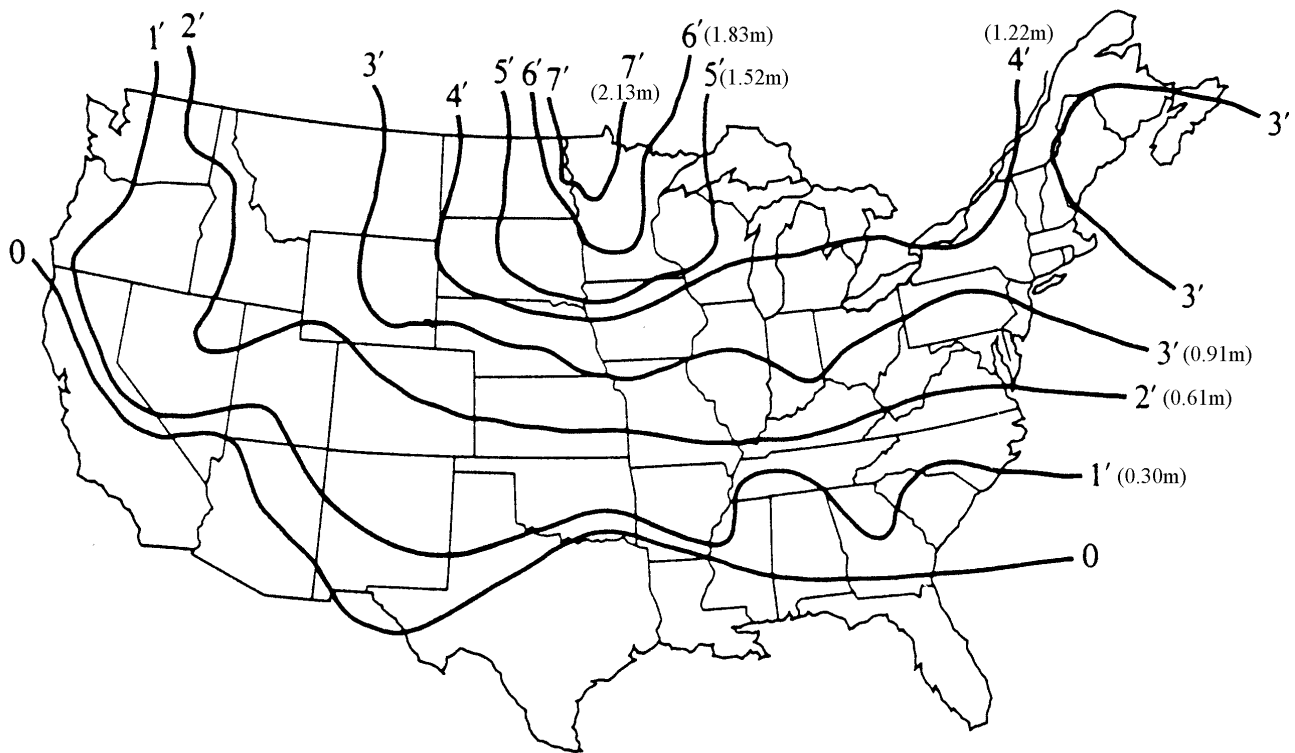
Figure 8-6: Approximate Frost-Depth Contours of the United States. Ref. Joseph E. Bowles,
Foundation Analysis and Design, Figure 7-1. Publisher-McGraw Hill Companies, Copyright © 1988.
Reproduced with permission of the McGraw Hill Companies.

8.3.5.3 Design for Uplift: For the design of a spread footing for uplift only, the ultimate net uplift force (based on design loads times the appropriate OLF) should be exceeded by the weight of the foundation and the weight of the soil that rests directly on the slab. Several sizes may be selected before one is obtained that will result in the desired safety factor, 1.5 minimum. **CAUTION:** In granular soils, the water table location may reduce the weight of the soil being relied upon for uplift resistance.

8.3.5.4 Design for Moment: A spread footing subject to overturning may be designed as follows:

Assume:

1. All resistance to overturning is furnished by the vertical load, weight of the concrete footing, and the weight of the soil block above the footing, the sum of which equals N.

2. The footing is rigid and tips about edge A.
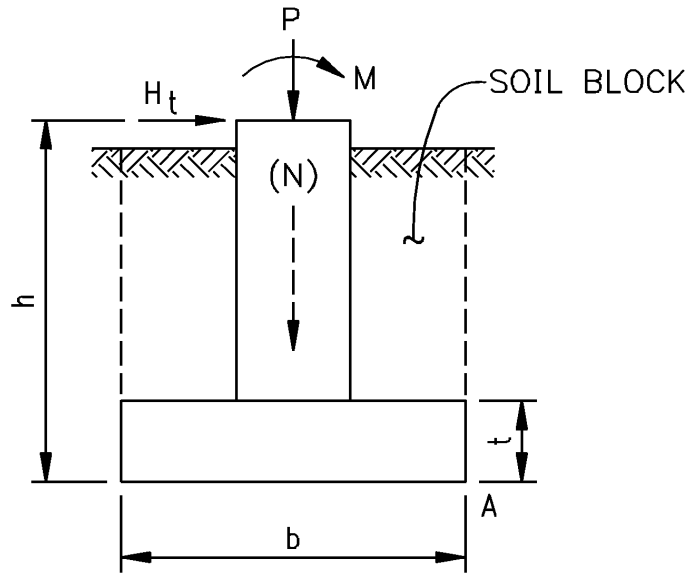
Figure 8-7: Spread Footing—General

Equation 8-17

$M_{ot} = M + H_t h$ (overturning moment)

Equation 8 - 18

$M_R = \dfrac{Nb}{2}$ (resisting moment)

Equation 8 - 19

F.S. $= \dfrac{M_R}{M_{ot}}$ between 1.5 and 2.0 is adequate for external stability

Equation 8-20

$e = \dfrac{M_{ot}}{N}$

Where:

e   =   Eccentricity measured from the centerline, in m (ft)

M_{ot} =   Overturning moment, in kN m (ft-lb)

Equation 8-21

$if \; e < \dfrac{b}{6}$ $p = \dfrac{N}{A} \pm \dfrac{M_{ot}}{S}$

p   =   Actual soil pressure, in kN/m^2 (psf)

A   =   Area of the footing, in m^2 (ft^2)

S   =   Section modulus of the bottom of the footing about the axis which the moment is acting

Equation 8-22

$S = \dfrac{db^2}{6}$

d   =   Width of footer, in m (ft)
b   =   Length of footer, in m (ft)
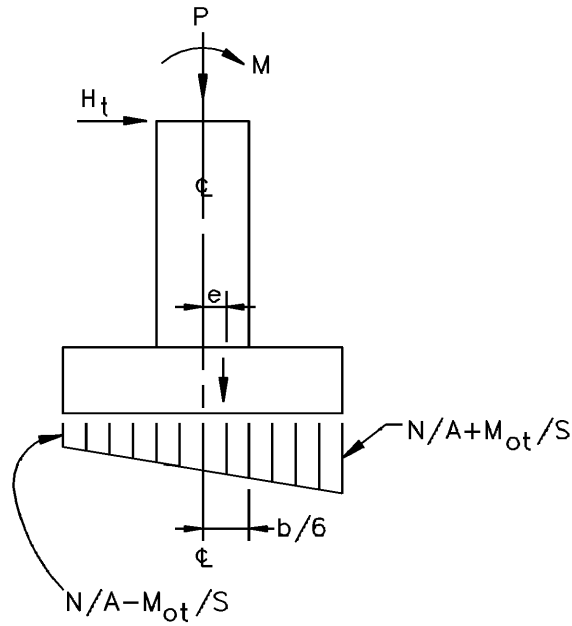
Figure 8-8: Spread Footing with $e < \dfrac{b}{6}$

$$if\ e > \frac{b}{6} \qquad p = \frac{2N}{d3\left(\dfrac{b}{2} - e\right)}$$
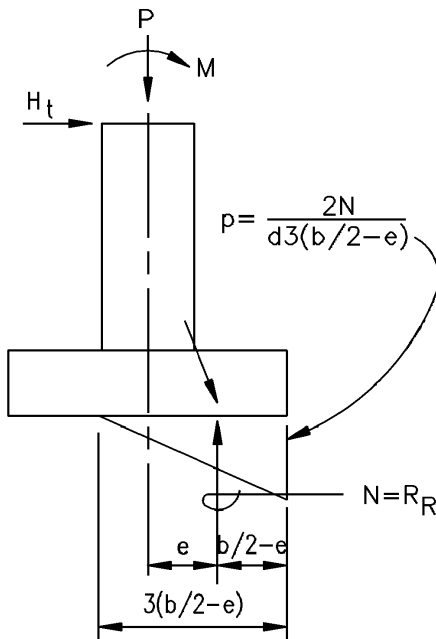
Figure 8-9: Spread Footing with $e > \dfrac{b}{6}$

Moments and shears are calculated for the concrete design of the slab and pier, and conventional concrete design is employed to complete the design:

Equation 8-23

$$M_z = \left(p - \frac{\ell p}{3x}\right)\frac{\ell^2}{2} + \left(\frac{\ell p}{3x}\right)\frac{\ell^2}{3}$$

Equation 8 − 24

$$V = \left(p - \frac{\ell p}{3x}\right)\ell + \left(\frac{\ell p}{3x}\right)\frac{\ell}{2}$$
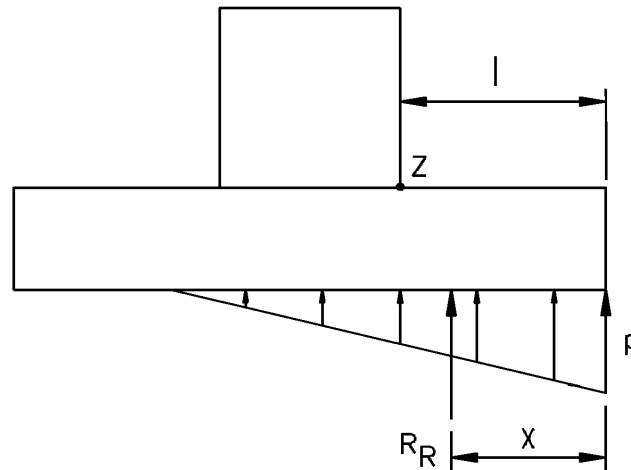
Figure 8-10: Spread Footing Elevation

Where
  M_z =   Bending moment about point z per unit width, in Nm/m (ft-lbs/ft)
      =   Distance from toe of footer to bending point
  x   =   Distance from toe of footer to the resultant reaction RR

8.3.5.4.1 Design Example 8-2: Given:

1.   Allowable bearing capacity of soil = 140 kN/m^2
2.   M = 40 kNm H_t = 4.5 kN   P = 11.0 kN
3. γ = 1600 kg/m^3 (assumed weight of soil)

Assume the water table is very deep and is not a factor.

Weight of pier = (0.6 m)^2 x 1.5 m x 2400 kg/m^3 =   1300 kg
Weight of slab = (2 m)^2 x .3 m x 2400 kg/m^3 =   2880 kg
Weight of soil = (4 m^2 – 0.36 m^2) x 1.35 m x 1600 kg/m^3 = 7860 kg
Weight of structure & equipment = (11.0 kN/9.8 N/kg) =   1120 kg
                                    N =   13,160 kg
                                    or   129,4 kN
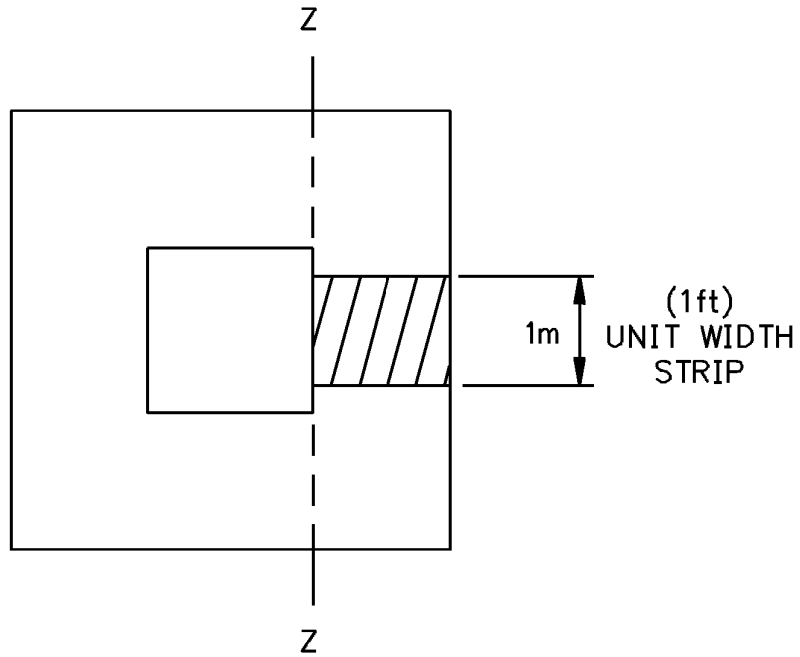
Figure 8-11: Spread Footing Plan
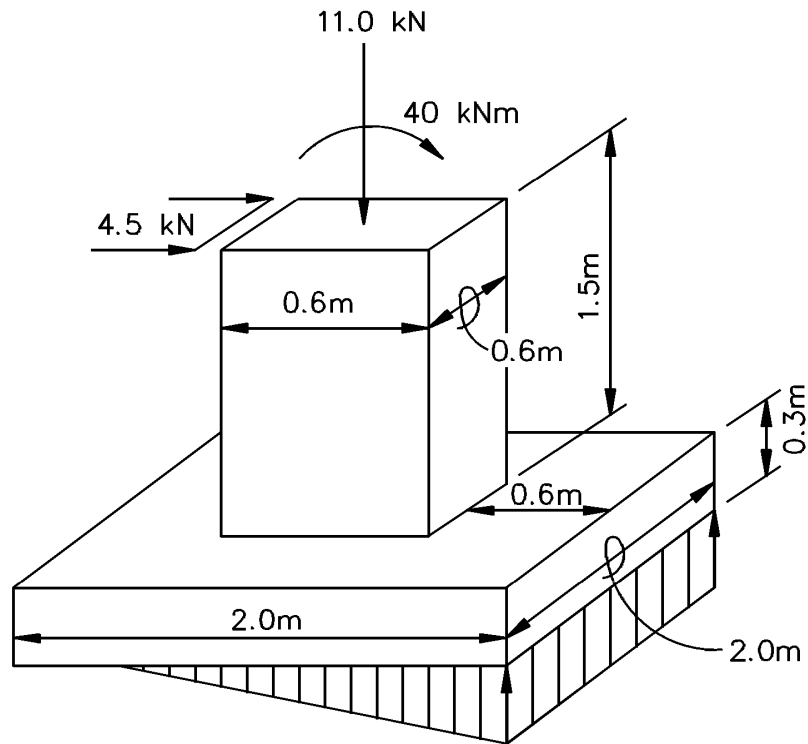
Figure 8-12: Spread Footing—3D Example

Check for Overturning:

$$M_{ot} = 40 \text{ kNm} + 1.8 \text{ m} \, (4.5 \text{ kN}) = 48.1 \text{ kNm}$$

$$M_R = 1 \text{ m} \, (9.8 \text{ N/kg}) 13{,}160 \text{ kg} = 129.4 \text{ kNm}$$

$$\text{F.S.} = \frac{129.4 \text{ kNm}}{48.1 \text{ kNm}} = 2.7 > 1.5 \quad \text{okay}$$

Locate Resultant Force:

$$e = \frac{48.1}{13.16(9.8)} = 0.37 \text{ m} > \frac{b}{6} = 0.33 \text{ m}$$

$$\text{therefore } p = \left(\frac{2}{3}\right) \frac{129.4 \text{ kN}}{(1 \text{ m} - 0.37 \text{ m}) 2 \text{ m}} = 68.5 \, \frac{\text{kN}}{\text{m}^2} < 140 \, \frac{\text{kN}}{\text{m}^2} \text{ okay}$$

Determine Bending Moment in Slab for use in calculating reinforcing steel:

$$M = \left[68.5 \, \frac{kN}{m^2} - \frac{0.6 \, m}{3(1 \, m - 0.37 \, m)} \, x \, 68.5 \, \frac{kN}{m^2} \right] \frac{(0.6 \, m)^2}{2} + (0.6 \, m)^2 \left[\frac{0.6 \, m}{3(1 \, m - 0.37 \, m)} \, x \, 68.5 \, \frac{kN}{m^2} \right] \frac{1}{2} \, x \, \frac{2}{3}$$

$$M = 11.0 \, kNm$$

The footing as shown above is slightly over designed. Additional trials could be made to reduce the size, if desired. Other steps for completing the reinforced concrete design should be completed by the engineer.

Determine Bending Moment in Pier for use in calculating reinforcing steel.
Assume that the pier is a vertical cantilever beam.
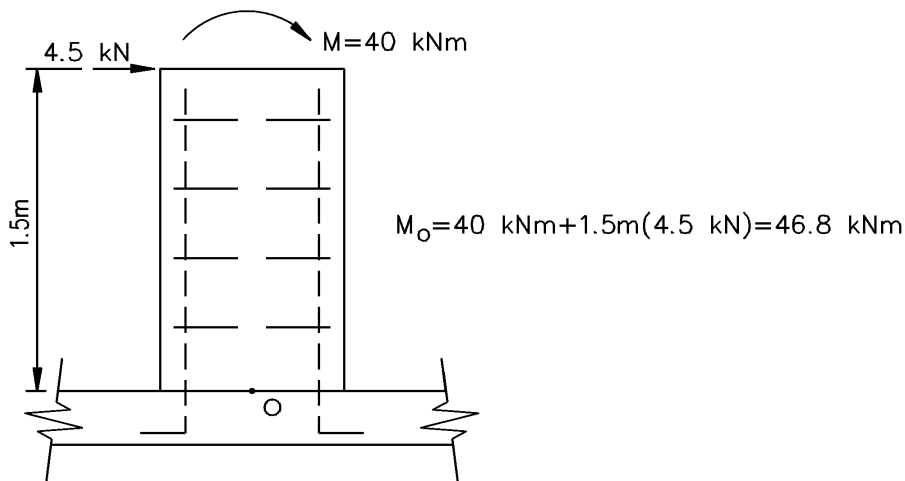
Figure 8-13: Spread Footing—2D Example

8.3.6 Slabs on Grade

8.3.6.1   General: Slabs on grade are sometimes used as foundations for miscellaneous equipment supports, switchgear, breakers, and power transformers. Slabs on grade should be used with caution where there is a chance of frost heave. This may cause problems with equipment that has rigid bus connections or in some other way may result in an operational malfunction of the equipment.

Slabs on grade may be satisfactory in frost-prone climates if the subgrade is essentially granular and well drained.

8.3.6.2   Subgrade Preparation: An important part of the installation of a slab on grade is the preparation of the subgrade. The soil should be thoroughly mixed and compacted to provide a nearly homogeneous, firm bearing surface. Proper preparation may help prevent objectionable settlement.

Slabs usually vary in thickness between 30 and 60 cm (12 and 24 inches) depending on the various design parameters. The slab should bear on the prepared subgrade and not on site stone or stone in oil retention sumps.

8.3.6.3   Applied Loads: The types of loads (compression and overturning) that are typically present in spread footings are also present in slab-on-grade foundations for equipment. Compression loads include the equipment weight and, in soil pressure calculations, the foundation weight. In the case of transformer foundations, the equipment weight plus the weight of the contained insulating oil has to be included. For transformers, jacking loads have to be also be considered. The jacking loads are considered by the structural engineer in a check for local punching failure through the slab. Jacking loads are "point" loads generated as hydraulic jacks are used to raise and level the transformer on the slab. There are typically four jacking points, one in each corner of the transformer.

Overturning loads occur when horizontal loads act on the equipment at the top of the slab on grade. While overturning moments in a spread footing are transferred to the base slab through the concrete pedestal, overturning loads on a slab on grade are transferred through the base of the equipment. Wind loads, seismic loads, and horizontal dynamic loads are included in the list of loads that would contribute to overturning. Horizontal dynamic loads might include the circuit-tripping load from an oil-filled circuit breaker. Also, equipment eccentricity can contribute to overturning. This is a case where the center of gravity of the equipment is not in line with the centerline of the slab.

8.3.6.4   Design for Stability: As with spread footings, slab-on-grade foundations have to be designed to not exceed the allowable soil pressure for the site. The allowable soil bearing pressure is site specific and should be determined by a geotechnical engineer following a subsurface investigation. In the absence of subsurface information, a reasonable range can be taken between 48 and 72 kN/m^2 (1000 and 1500 psf). This, however, may or may not be a conservative range for the given site.

In addition to keeping the soil pressure below the slab under an allowable limit, an adequate safety factor against overturning has to be maintained. The approach is similar to that for spread footings.

8.3.6.4.1 Design Example 8-3:

Check the soil bearing pressure and the factor of safety against overturning for a transformer slab based on the following assumptions:

161/13.2 kV transformer weight   110,900 kg
Insulating Oil   58,060
Total transformer weight   168,960 kg x 9.8 N/kg = 1656 kN

Transformer base dimensions: 584 cm x 320 cm

Foundation size: 650 cm long x 400 cm wide x 60 cm thick

Weight of foundation = (6.50 m x 4.00 m x 0.60 m) x 23.6 kN/m^3 = 368 kN
(concrete: 23.6 kN/m^3 = 150 pcf)
Total vertical load, N = 1656 kN + 368 kN = 2024 kN

Given allowable soil bearing pressure, P, based on soil report = 144 kN/m^2 (3000 psf)

Calculate overturning moment M_{ot}.

For a transformer in a seismically active area, seismic load usually controls rather than wind load because of the transformer's relatively large mass. For this example, assume the transformer is in seismic Zone 2A and that it has been determined that seismic loads control.

The horizontal seismic load would be calculated as follows:

Based on IEEE Std. C57.114, "IEEE Seismic Guide for Power Transformers and Reactors," for a Zone 2A region, where the weight of the transformer, W_{tr}, is 1656 kN,

> Horizontal Load: 0.2 x W_{tr} = 331 kN
> Vertical Load: 2/3(0.2 x W_{tr}) = 221 kN

Calculate the overturning moment due to the seismic load:

> Given:
> The center of gravity of the transformer is 150 cm above the top of the foundation.
> The slab is 60 cm thick.
>
> The center of gravity of the transformer is 10 cm off the longitudinal centerline of the foundation.

Overturning moment (seismic):

> Horizontal Load: 331 kN x (1.5 m + 0.60 m)   = 695 kN
> Vertical Load: 221 kN x 0.10 m   =   22 kN
> Total seismic overturning moment   = 717 kN

Calculate the overturning moment due to equipment eccentricity:

> Overturning moment (eccentricity)   = 1656 kN x 10 cm
>   = 166 kNm

Calculate the total overturning moment:

$M_{ot} = 717$ kNm + 166 kNm = 883 kNm

Calculate the soil bearing pressure:

Eccentricity, $e = M_{ot}/N$

$e = 883$ kNm/2024 kN = 0.44 m
$b/6 = 4.0$ m/6 = 0.67 m
$e < b/6$; therefore, $p = N/A \pm M_{ot}/S$

Slab area, A = 6.5 m x 4.0 m = 26 m^2
Slab section modulus, S = 6.5 m x $(4.0$ m$)^2/6 = 17.3$ m^3

Soil bearing pressure, $p = 2024$ kN/26 $m^2 \pm 883$ kNm/17.3 m^3
$\quad = 77.8$ kN/$m^2 \pm 51.0$ kN/m^2
$p_{max} = 128.8$ kN/$m^2 < 144$ kN/m^2 O.K.

Calculate the safety factor against overturning (has to be greater than 1.5):

$M_{ot} = 883$ kNm

Calculate the moment that resists overturning (M_R):

Weight of transformer = 1656 kN

Weight of foundation = 368 kN

$M_R = (1656$ kN x 1.9 m$) + (368$ kN x 2 m$) = 3882$ kNm

F.S. = $M_R/M_{ot} = (3882$ kNm $) / (883$ kNm$) = 4.4 > 1.5$ O.K.

8.3.6.5 Minimum Reinforcing Steel: Foundation reinforcing steel is designed based on the American Concrete Institute *Building Code Requirements for Reinforced Concrete* (ACI 318). Although reinforcing steel design is beyond the scope of this chapter, a certain minimum level of reinforcing has to be maintained. ACI 318 specifies that a steel area of at least 0.0018 times the gross concrete area has to be provided. This is provided to prevent shrinkage cracks from forming as the concrete dries. For the foundation in the example above, the minimum area of reinforcing (A_s) for a unit width strip of 1 meter would be:

$A_s = 0.0018$ x 1 m x 0.60 m
$\quad = 0.00108$ m^2/m of slab length = 1080 mm^2/m of slab length

One combination that would satisfy the above minimum requirement would be:

#5 bars @ 30 cm on center, top and bottom, each way.

The cross-sectional area of a #5 bar = 200 mm^2
For #5 top and bottom multiply by 2 bars:
$A_s = (2)200$ mm^2 x (100 cm/1 m)/30 cm = 1333 mm^2/m > 1080 mm^2/m   O.K.
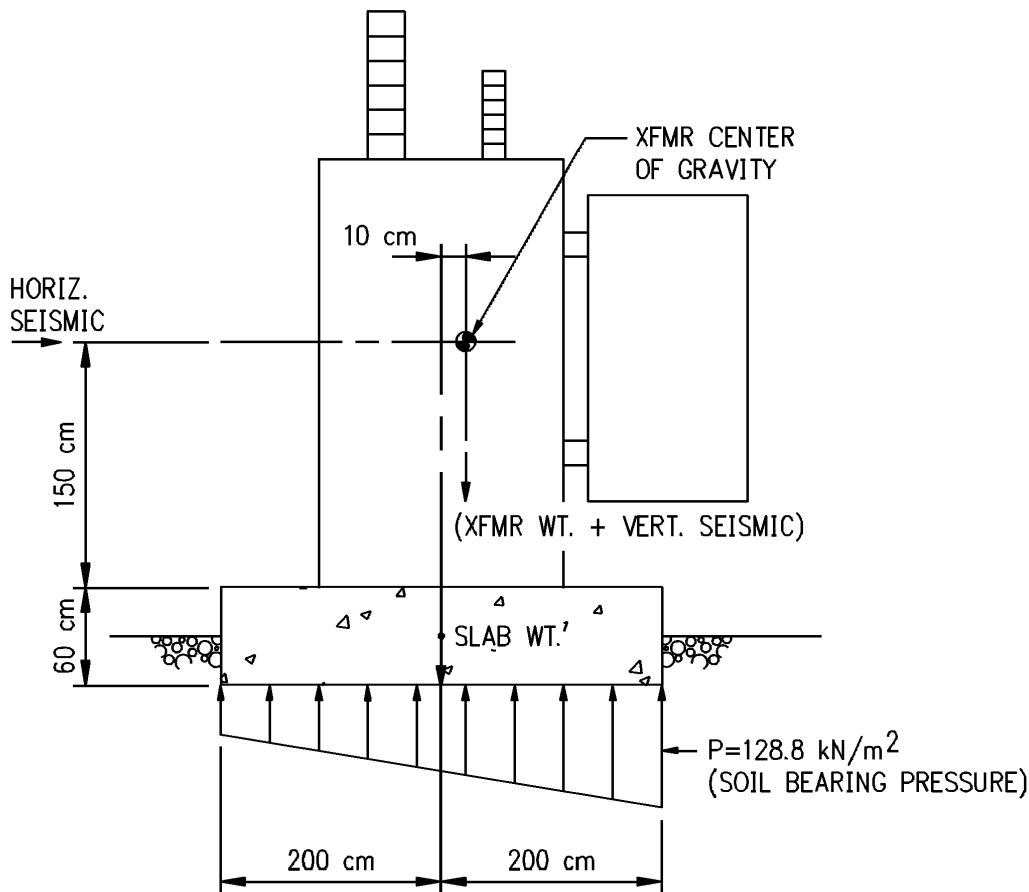
Figure 8-14: Transformer Slab Loading

8.4   OIL POLLUTION

Oil pollution from transformers and other substation equipment is discussed in Chapter 2.

Federal law, the Code of Federal Regulations, 40 CFR, Chapter 1, Parts 110 and 112, requires the containment of potential oil spills for any facility that contains oil stored underground in excess of 42,000 gallons or a capacity stored above ground in excess of 1320 gallons, or any single container with a capacity greater than 660 gallons. The regulations further require that when a situation as described above exists in a substation, and an oil spill could reasonably be expected to discharge into or upon navigable waters, that a "Spill Prevention, Control, and Countermeasure" plan (SPCC plan) has to be prepared. Detailed information concerning SPCC plan requirements and preparation are contained in 40 CFR 112. Other sources for a detailed discussion of oil spill prevention requirements and techniques are ANSI/IEEE Std. 980 and RUS Bulletin 1724E-302, "Design Guide for Oil Spill Prevention and Control at Substations."

If oil pollution abatement is necessary, the degree of reliability that is desired has to be decided. The primary function of all systems is to prevent oil from reaching prohibited areas, including the ground water table and any navigable waters.

A determination has to be made as to whether the system will be self-operating or should be monitored periodically or seasonally.

8.4.1 Basic Retention System

This system should include an impervious, lined, open or stone-filled sump area around the oil containment vessel (transformer). Usually stone 5 to 9 cm (2 to 3½ inches) is desirable in the sump area to provide operators and maintenance personnel easy access to and around the transformer. The size and gradation of the stone affects the percentage of voids available to store oil. Stone of the size mentioned above may provide 25 to 40 percent voids. Perforated pipe placed in the bottom of the sump will convey, by gravity flow, water and oil to an underground storage tank. The tank has to have a sump pump to periodically pump out the water that has collected from rainfall. The pump may be regulated to cut on and off by a float valve or pressure switches. The transformer also should have a low-oil-level alarm that deactivates the sump pump.

At the cutoff position, there should be at least 6 inches of water covering the bottom of the tank. This enables small or slow oil leaks to be stored on top of the water. The storage tank should be designed to retain all the oil in one transformer between cutoff water level and inlet pipe.

The oil is removed from the tank by pump trucks.

The system is costly but reasonably reliable. Mechanical failure of the sump pump is a disadvantage.

A variation of the approach discussed above is the utilization of a special oil-sensing control unit that works with a submersible drainage pump. The pump is placed in a vault outside the sump as described above. The pump discharges rainwater from the system, but is deactivated by the control unit when oil is detected.

8.4.2 Oil Separator Tank

This system is feasible only where there is sufficient gradient for gravity discharge from the underground tank. See Figure 8-15.

The oil or water is collected from the transformer area as it was in the basic retention system. It is discharged into an oil separator tank. The principle upon which this system operates is that oil is lighter than water and floats upon it.

The oil separator tank should be designed to contain all the oil in one transformer should a major rupture occur. This system allows the water to continuously pass through but retains the oil. The oil retained in the tank has to be pumped into a tank truck and disposed of.

This system is costly but quite reliable.

The oil separator tank principle may be applied to above-grade diked basins where freezing temperatures are not prevalent.

Modification to the above-grade separator system may be considered when regular inspection is anticipated. It could consist of a transformer area that is lined and diked with impervious material. A short piece of 4-inch pipe passes through the dike and contains a shutoff valve that may be left open for continuous drainage and closed in an emergency when alarms occur or inspection indicates.
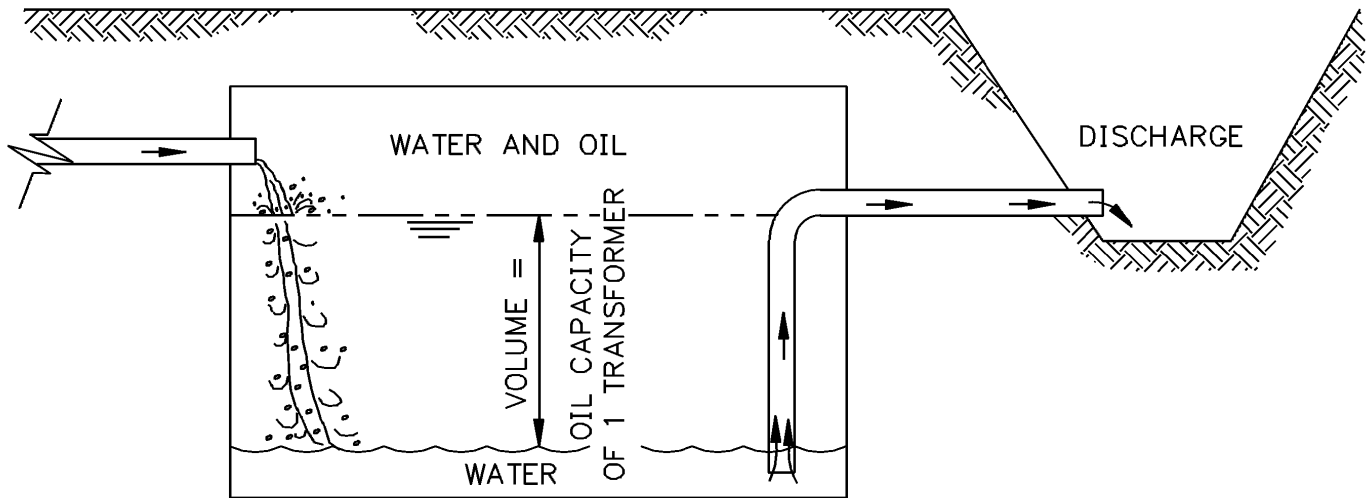
Figure 8-15: Oil Separator Tank

An alternative approach is to leave the valve closed and then open it as necessary to drain the collected water at periodic inspections.

This system is relatively economical but requires a greater level of maintenance.

8.4.3 <u>Summary</u>

Each solution to the oil abatement problem is not without its own problems. These should be evaluated along with system costs when deciding on the most desired system at each substation. The ultimate goal is to make sure all oil within the substation remains on site.

8.5 REFERENCES

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APPENDIX E

SPECIFICATION
FOR
PROCURING
GEOTECHNICAL SUBSURFACE INVESTIGATION

The following Specification for Procuring Geotechnical Subsurface Investigation is offered as a general guideline. This specification is general, incomplete, and prepared in a way to obtain non-professional geotechnical drilling and testing services, performed in this instance under a specific and pre-defined scope of work. Therefore, it is geared toward providing only raw data and not professional engineering recommendations.

Contractual clauses from your cooperative's legal department should be incorporated along with these technical specifications. Additional clauses regarding insurance requirements, potentially contaminated soils, ownership of documents, and limitation of liability are among those issues frequently covered in common corporate clauses.

SPECIFICATION
FOR
PROCURING
GEOTECHNICAL SUBSURFACE INVESTIGATION

1. SCOPE

1. The work shall consist of making soil borings to determine the nature and extent of the soil strata at the _____ Substation near _____, _____ . Laboratory testing shall be required on undisturbed samples as outlined in the Specifications. Drawing _____ is a part of this Specification and indicates the approximate location of proposed borings.

2. GENERAL

1. The Geotechnical Engineering Consultant (Consultant) shall furnish all necessary equipment, materials, and labor to complete the borings at the locations shown on Drawing _____.

2. The Consultant shall be responsible for all damage to public and private property resulting from the operations of its employees.

3. The Consultant shall also comply with all Federal, State, and local rules and regulations with regard to permits, bonds, drilling, plugging, and all other applicable aspects of well drilling.

4. The Consultant shall review the proposed scope of work indicated as a minimum level of services desired relative to the anticipated subsurface conditions present. If localized subsurface conditions are expected to vary significantly, Consultant shall advise Owner of additional recommended services prior to commencing work.

5. The Consultant shall evaluate the stratigraphic soil, rock, and phreatic water level information at the Site so as to assist in configuring the depth and size of the proposed structures.

6. The Consultant shall conduct a subsurface investigation and laboratory testing program and prepare final boring logs and laboratory results. These services are described in more detail later in this Specification, but include the following tasks:

   a. Perform an exploration program and provide qualified field personnel to log the borings.
   b. Perform laboratory tests on samples obtained from the borings to evaluate pertinent engineering properties of materials encountered.
   c. Provide a final report containing a description of the field and laboratory testing programs, boring location plan, typed boring logs, and laboratory test results.

3. WORKMANSHIP AND METHODS

1. Borings shall be performed by the Consultant at the locations previously staked in the field and as shown on the Drawing.

2. In soil that is predominantly cohesionless, Consultant shall perform the standard penetration test in accordance with ASTM Specification D1586. Consultant shall use a 2" O.D. x 1-3/8" I.D. split tube sampler and a 140-lb weight free falling 30 inches. Record the number of blows per 12 inches of penetration at each change in stratification or character of the soil but at intervals not exceeding 3 feet for the first 15 feet below grade and at 5-foot intervals thereafter.

3. In soil that is predominantly cohesive, Consultant shall use the thin-walled tube method for sampling in accordance with ASTM Specification D1587. Consultant shall take samples in each change of stratification but at intervals not exceeding 3 feet for the first 15 feet below grade and at 5-foot intervals thereafter.

4. Boring in hard strata or rock shall be performed by diamond coring in accordance with ASTM D2113.

5. The depth of borings is indicated on the attached Drawing. If boulders or materials are encountered that prevent penetration to the required depth, the location of the boring shall be changed a maximum of 10 feet for a second boring. If refusal occurs on the second boring in less than 15 feet below grade, the boring shall be considered complete.

6. The Consultant shall be cognizant of the fact that borings are being obtained for foundation design information. If it becomes apparent during the boring operation that the material throughout the depth of the borings is unusually soft or the standard penetration values are very low so that it might appear that piling might be necessary, the Consultant shall so inform the proper authority, in this case, Mr. Mrs. Ms._____ who may be reached at _____ . The Consultant shall not leave the site until the Consultant is further notified of what action is desired. Such notification is not anticipated to take more than one-half day.

7. Borings shall be advanced with drilling methods that minimize the potential for disturbance, sloughing, or mixing of materials within soil samples. When water is encountered within a hole in cohesionless or sand material, rotary wash drilling methods with bentonite or polymer slurry shall be used in which positive head is maintained within the hole. Rotary wash drilling should be anticipated. Consultant shall provide casing, if required. Water levels encountered, as well as the method used in advancing drilling, shall be indicated by Consultant on the respective boring logs.

8. Consultant shall obtain calibrated hand penetrometer readings on all cohesive samples in the field. Consultant shall seal samples to prevent disturbance and moisture changes and transport to the laboratory for testing.

9. Laboratory tests shall be assigned by _____ and performed by the Consultant to classify soils and obtain geotechnical physical characteristics. Consultant shall provide copies of the rough field boring logs upon completion to _____ so that laboratory tests may be assigned. Consultant shall perform laboratory testing consistent in quality with current, applicable ASTM Standards. The following estimate of laboratory testing is provided as our best estimate at this time and may vary based on actual materials encountered and samples obtained.

[Insert Table of Anticipated Testing; To Be Prepared by Cooperative]

4. FINAL REPORT

1. Four copies of the final report shall be mailed to Mr. Mrs. Ms. _____ not later than two weeks after the drilling operations have been completed.

2. The Consultant's report shall include the following:

    a. Project identification, boring number, location and driller.
    b. Depth of topsoil.
    c. Elevation of groundwater at completion of boring and also 24 hours after completion, including dates and times measured.
    d. Vertical plot sections, referred-to datum, showing type and descriptive classification of material encountered and the upper boundary elevation of each successive soil strata. Descriptive classification shall include group symbol of the Unified Soil Classification System.
    e. Number of blows per 12-inch penetration from standard penetration test.
    f. Dry density of soil and moisture content.
    g. Unconfined compressive strength tests on all cohesive soils procured and selected from the samples for testing.
    h. Date of beginning and end of boring.
    a. If it is necessary to stop boring or move a hole due to obstruction, breaking of casing, etc., it shall be noted and properly described.

CHAPTER 9
GROUNDING

9.1 GENERAL

This chapter is concerned with safe grounding practices and design for outdoor ac substations (distribution and transmission) for power frequencies in the range of 50 to 60 Hz. DC substations and the effect of lightning surges are not covered by this chapter.

An effective substation grounding system typically consists of driven ground rods, buried interconnecting grounding cables or grid, equipment ground mats, connecting cables from the buried grounding grid to metallic parts of structures and equipment, connections to grounded system neutrals, and the ground surface insulating covering material. Currents flowing into the grounding grid from lightning arrester operations, impulse or switching surge flashover of insulators, and line-to-ground fault currents from the bus or connected transmission lines all cause potential differences between grounded points in the substation and remote earth. Without a properly designed grounding system, large potential differences can exist between different points within the substation itself. Under normal circumstances, it is the current flow through the grounding grid from line-to-ground faults that constitutes the main threat to personnel.

An effective grounding system has the following objectives:

1. Ensure such a degree of human safety that a person working or walking in the vicinity of grounded facilities is not exposed to the danger of a critical electric shock. The touch and step voltages produced in a fault condition have to be at safe values. A safe value is one that will not produce enough current within a body to cause ventricular fibrillation.
2. Provide means to carry and dissipate electric currents into earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service.
3. Provide grounding for lightning impulses and the surges occurring from the switching of substation equipment, which reduces damage to equipment and cable.
4. Provide a low resistance for the protective relays to see and clear ground faults, which improves protective equipment performance, particularly at minimum fault.

It should be recognized that there is no overall record of injuries resulting from deficient grounding systems. Equally, however, it should be appreciated that, with more substations being built, higher fault currents become possible. Therefore, it is becoming more important to protect against personal injury and equipment damage.

While line-to-ground faults may result in currents of tens of thousands of amperes lasting several seconds, modern relay systems generally reduce the fault duration to a few cycles. During fault current flow, a low ground grid resistance to remote earth, although desirable, will not, in itself, necessarily provide safety to personnel. It is necessary that the entire grounding system be designed and installed so that, under reasonably conceivable circumstances, personnel are not exposed to hazardous potential differences across the body.

Designing a proper substation grounding system is complicated. Numerous parameters affect its design, and it is often difficult to obtain accurate values for some of these parameters. Furthermore, temperature and moisture conditions can cause extreme variations in the actual resistivity of the ground in which the

system is installed. Methods of dealing with the design problem are necessarily based to some extent on approximations and the exercise of engineering judgment. The design approach has to be conservative because of the aforementioned uncertainties.

A good grounding system provides a low resistance to remote earth in order to minimize the ground potential rise. For most transmission and other large substations, the ground resistance is usually about 1 Ω or less. In smaller distribution substations the usually acceptable range is from 1 to 5 Ω, depending on local conditions.

For reference material, IEEE Std. 80, "Guide for Safety in Substation Grounding," is generally recognized as one of the most authoritative guides available. It is recommended for any person concerned with the design of substation grounding systems. A bibliography in the IEEE guide lists important additional references, including abstracts of many of them.

This chapter describes some of the different modes in which ground fault current may flow with respect to substation grounding systems. Included is discussion of safety considerations in and near substations when all or a portion of this fault current flows through the substation grounding system. Specific recommendations for the design, installation, and testing of safe and effective grounding systems for RUS substations are included.

The design procedures presented in this chapter are based on IEEE Std. 80, "Guide for Safety in Substation Grounding." IEEE Std. 80 presents a simplified design procedure for substation grounding that meets the required safety criteria without the use of an expensive computer software program. The sections of this chapter are presented in the order in which they should be performed.

The first aspect of substation grounding is how to take and analyze soil resistivity measurements (Section 9.3). Next, Section 9.4 shows the importance of the area of the ground grid. Section 9.5 discusses and illustrates some of the cases governing fault current flow. The engineer will use the split factor (Section 9.5.2) to take into account that not all of the fault current uses the earth as a return path. The split factor can be calculated from graphs instead of formulas; these graphs are one of the major improvements to grounding design from previous grounding design manuals.

Once the maximum grid current is determined (Section 9.5.4), the engineer will use the maximum grid current to choose the type and size of the ground grid conductors needed (Section 9.6). Section 9.6 also examines how to connect substation equipment to the ground grid and the type of connector to use. Section 9.7.1 shows the importance of high-speed relays by calculating the tolerable limits of current to the body, and in Section 9.7.2 the typical shocks situations are illustrated in Figures 9-28 and 9-29 (see page 541 and 542 of this bulletin). Tolerable touch and step voltages are discussed in Section 9.8, which are the design criteria of a safe grounding design. Section 9.9 provides the benefits of protective surface materials, such as gravel, in improving the tolerable touch and step voltages.

In Section 9.10, all the information in the previous sections is pulled together in a step-by-step approach to designing a substation grounding system. Once a safe ground grid has been designed, the proper grounding of the substation fence (Section 9.10.10.1) and the operating handles on switches, cable sheaths, and surge arresters (Section 9.10.10.3) is discussed.

9.2   DEFINITIONS

9.2.1   DC Offset

Difference between the symmetrical current wave and the actual current wave during a power system transient condition. Mathematically, the actual fault current can be broken into two parts: a symmetrical alternating component and a unidirectional (dc) component. The unidirectional component can be of either polarity, but will not change polarity and will decrease at some predetermined rate.

9.2.2   Earth Current

The current that circulates between the grounding system and the ground fault current source that uses the earth as the return path.

9.2.3   Ground Fault Current

A current flowing into or out of the earth or an equivalent conductive path during a fault condition involving ground.

9.2.4   Ground Potential Rise (GPR)

The maximum voltage that a ground grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. The GPR is equal to the product of the earth current and the equivalent impedance of the grounding system.

9.2.5   Mesh Voltage

The maximum touch voltage within a mesh of a ground grid.

9.2.6   Soil Resistivity

The electrical characteristic of the soil with respect to conductivity. The value is typically given in ohm-meters.

9.2.7   Step Voltage

The difference in surface potential experienced by a person bridging a distance of 1 meter with his feet without contacting any other grounded object.

9.2.8   Touch Voltage

The potential difference between the ground potential rise and the surface potential at the point where a person is standing while at the same time having his hands in contact with a grounded structure.

9.2.9   Transferred Voltage

A special case of the touch voltage where a voltage is transferred into or out of the substation from or to a remote point external to the substation site.

9.3   SOIL RESISTIVITY MEASUREMENTS

Before the design process can begin, soil resistivity measurements should be taken at the substation site. Make these at a number of places within the site. Substation sites where the soil may possess uniform resistivity throughout the entire area and to a considerable depth are seldom found. Typically, there are several layers, each having a different resistivity. Often, lateral changes also occur, but, in comparison to the vertical ones, these changes usually are more gradual. Make soil resistivity tests to determine if there are any important variations of resistivity with depth. The number of such readings taken should be greater where the variations are large, especially if some readings are so high as to suggest a possible safety problem.

A number of measuring techniques are described in detail in IEEE Std. 81-1983. The Wenner four-pin method as shown in Figure 9-1 is the most commonly used technique. In brief, four probes are driven into the earth along a straight line, at equal distances a apart, driven to a depth b. The voltage between the two inner (potential) electrodes is then measured and divided by the current between the two outer (current) electrodes to give a value of resistance, R. Then,

> Equation 9-1
>
> $$r_a = \frac{4\pi a R}{1 + \frac{2a}{\sqrt{a^2 + 4b^2}} - \frac{a}{\sqrt{a^2 + b^2}}}$$

Where:

r_a	=	Apparent resistivity of the soil in Ω-m
R	=	Measured resistance in ohms
a	=	Distance between adjacent electrodes in meters
b	=	Depth of the electrodes in meters

If b is small compared to a, as is the case of probes penetrating the ground only a short distance, Equation 9-1 can be reduced to Equation 9-2:

> Equation 9-2
>
> $$\rho_a = 2\pi a R$$

The current tends to flow near the surface for the small probe spacing, whereas more of the current penetrates deeper soils for large spacing. Thus, it is usually a reasonable approximation to assume that the resistivity measured for a given probe spacing a represents the apparent resistivity of the soil to a depth of a when soil layer resistivity contrasts are not excessive. Equations 9-1 and 9-2, thus, can be used to determine the apparent resistivity r_a at a depth a.

There are a number of reasons for the popularity of the Wenner four-pin method shown in Figure 9-1. The four-pin method obtains the soil resistivity data for deeper layers without driving the test pins to those layers. No heavy equipment is needed to perform the four-pin test. The results are not greatly affected by the resistance of the test pins or the holes created in driving the test pins into the soil.

Resistivity measurement records should include temperature data and information on the moisture content of the soil at the time of measurement. Also record all data available on known buried conductive objects in the area studied. Buried conductive objects in contact with the soil can invalidate resistivity

measurements if they are close enough to alter the test current flow pattern. This is particularly true for large or long objects.
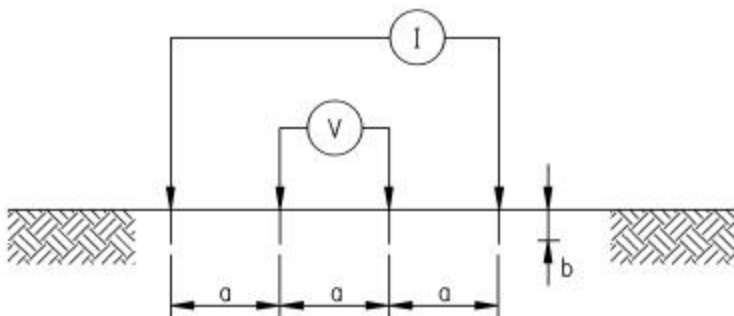
Figure 9-1: Wenner Four-Pin Method. Ref. IEEE Std. 80, Draft 13, June 19, 1998, Figure 13-1. Copyright © 1998. IEEE. All rights reserved.

A good reference useful for an understanding of both resistivity and grounding system resistance measurements is contained in the manual entitled *Getting Down-To-Earth* by the Biddle Co. This manual is available from AVO International, 261 Van Buren Rd., Trooper, Pennsylvania 19403, order number AVTM25TA (www.avointl.com). Helpful information is also given in IEEE Stds. 81 and 81.2.

9.3.1 <u>Analyzing Soil Resistivity Measurements</u>

Interpretation of apparent resistivity obtained in the field is perhaps the most difficult part of the measurement program. The basic objective is to derive a soil model that is a good approximation of the actual soil. Soil resistivity varies laterally and with respect to depth, depending on the soil stratification. Seasonal variations may occur in soil resistivity due to varying weather conditions. It has to be recognized that the soil model is only an approximation of the actual soil conditions and that a perfect match is unlikely.

The most commonly used soil resistivity models are the uniform soil model and the two-layer soil model. Two-layer soil models are often a good approximation of many soil structures while multi-layer soil models may be used for more complex soil conditions. Interpretation of the soil resistivity measurements may be accomplished either manually or by use of computer analysis techniques described in numerous references.

A uniform soil model should be used only when there is a moderate variation in apparent resistivity. In homogeneous soil conditions, which rarely occur in practice, the uniform soil model may be reasonably accurate. If there is a large variation in measured apparent resistivity, the uniform soil model is unlikely to yield accurate results.

A more accurate representation of the actual soil conditions can be obtained through use of a two-layer model. The two-layer model consists of an upper layer of finite depth and with different resistivity than a lower layer of infinite thickness. There are several techniques to determine an equivalent two-layer model from apparent resistivity obtained from field tests. In some instances a two-layer model can be approximated by visual inspection of a plot of the apparent resistivity versus depth from driven rod measurements or apparent resistivity versus probe spacing from Wenner four-pin measurements.

Computer programs available to the industry may also be used to derive two-layer and multi-layer soil models.

Since the simplified design procedures of IEEE Std. 80 require a uniform soil assumption, a single value for soil resistivity will have to be chosen.

9.3.2 Uniform Soil Assumption

A uniform soil model can be used instead of the multi-layer soil model whenever the two-layer or multi-layer computation tools are not available. Unfortunately, an upper bound of the error on all relevant grounding parameters is difficult to estimate. In general, however, when the contrast between the various layer resistivities is moderate, an average soil resistivity value may be used as a first approximation or to establish orders of magnitude. The approximate uniform soil resistivity may be obtained by taking a mathematical average of the measured apparent resistivity data as shown in Equation 9-3.

Equation 9-3

$$ \boldsymbol{r}_{a(av1)} = \frac{\boldsymbol{r}_{a(1)} + \boldsymbol{r}_{a(2)} + \boldsymbol{r}_{a(3)} + \ldots + \boldsymbol{r}_{a(n)}}{n} $$

Where:

$\boldsymbol{r}_{a(1)}, \boldsymbol{r}_{a(2)}, \boldsymbol{r}_{a(3)} \ldots \boldsymbol{r}_{a(n)}$ = Measured apparent resistivity data obtained at different spacing in the four-pin method or at different depths in the driven ground rod method in Ω-m

n = Total number of measurements

Other methods to approximate uniform soil resistivity can be found in IEEE Std. 80.

9.4 AREA OF THE GROUND GRID

The area of the ground grid should be as large as possible, preferably covering the entire substation site. All of the available area should be used since this variable has the greatest effect in lowering the grid resistance. Measures such as adding additional grid conductor are expensive and do not reduce the grid resistance to the extent that increasing the area does.

In general, the outer grid conductors should be placed on the boundary of the substation site with the substation fence placed a minimum of 3 feet inside the outer conductors. This results in the lowest possible grid resistance and protects persons outside the fence from possibly hazardous touch voltages. It is therefore imperative that the fence and the ground grid layout be coordinated early in the design process.

The simplified design equations require square, rectangular, triangular, T-shaped, or L-shaped grids. For preliminary design purposes, on a layout drawing of the substation site, draw in the largest square, rectangular, triangular, T-shaped, or L-shaped grids that will fit within the site. These represent the outer grid conductors and will define the area of the grid to be used in the calculations. A square, rectangular, triangular, T-shaped, or L-shaped grid site generally requires no additional conductors once the design is complete. For irregular sites, once the design has been completed, additional conductors will be run along the perimeter of the site that were not included in the original grid design and connected to the grid. This will take advantage of the entire site area available and will result in a more conservative design.

9.5 GROUND FAULT CURRENTS

When a substation bus or transmission line is faulted to ground, the flow of ground current in both

magnitude and direction depends on the impedances of the various possible paths. The flow may be between portions of a substation ground grid, between the ground grid and surrounding earth, along connected overhead ground wires, or along a combination of all these paths.

The relay engineer is interested in the current magnitudes for all system conditions and fault locations so that protective relays can be applied and coordinating settings made. The designer of the substation grounding system is interested primarily in the maximum amount of fault current expected to flow through the substation grid, especially that portion from or to remote earth, during the service lifetime of the installed design.

Figures 9-2 through 9-5 illustrate some of the cases governing ground fault current flow. The worst case for fault current flow between the substation grounding grid and surrounding earth in terms of effect on substation safety has to be determined. The maximum symmetrical rms fault current at the instant of fault initiation is usually obtained from a network analyzer study or by direct computation. IEEE Std. 80 provides methods for direct computation of the maximum symmetrical rms fault current.
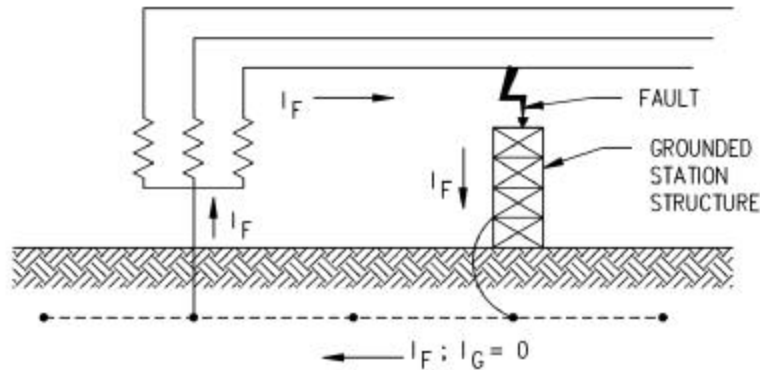
Figure 9-2: Fault Within Local Substation, Local Neutral Grounded.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 15-1. Copyright © 1998. IEEE. All rights reserved.
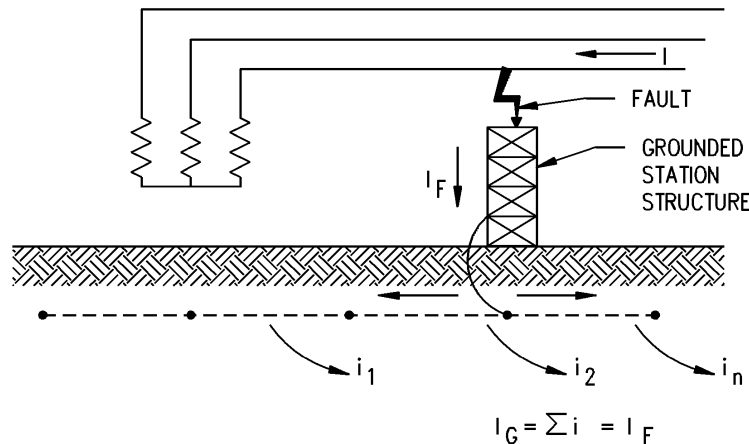
Figure 9-3: Fault Within Local Substation, Neutral Grounded at Remote Location.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 15-2. Copyright © 1998. IEEE. All rights reserved.

$$I_F = I_{F_1} + I_{F_2}$$

$$I_{F_1} \rightarrow$$

FAULT

$$\leftarrow I_{F_2}$$

$$\leftarrow I_{F_2}$$

GROUNDED
STATION
STRUCTURE

$$I_F \downarrow$$

$$\uparrow I_{F_1}$$

OTHER
SYSTEM
GROUNDS

$$I_G = I_F - I_{F_1}$$

$$I_G$$

Figure 9-4: Fault in Substation; System Grounded at Local Station and also at Other Points.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 15-3. Copyright © 1998. IEEE. All rights reserved.

REMOTE
SOURCE

DISTRIBUTION
SUBSTATION

LOAD
SUBSTATION

øA
øB
øC

øA (73)
øB (103)
øC (70)

(12)

(12)

(12)

(1492)

1492

338

444

338

448

99

I_G = 1048

I_G = 742

I_G = 99
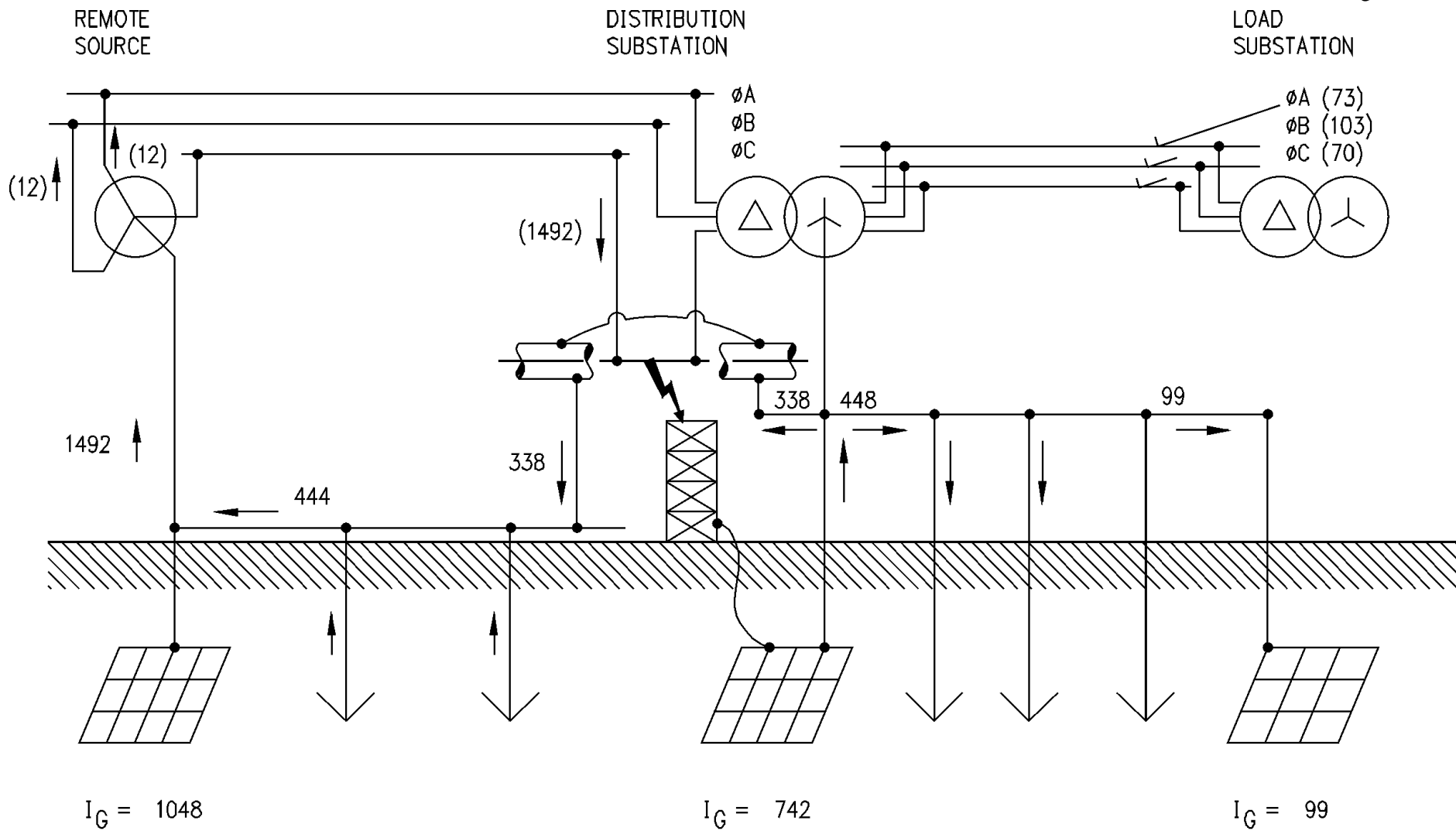
Figure 9-5: Typical Current Division for a Fault on High Side of Distribution Substation.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 15-4. Copyright © 1998. IEEE. All rights reserved.

9.5.1 <u>Symmetrical Grid Current</u>

That portion of the symmetrical ground fault current that flows between the grounding grid and surrounding earth may be expressed by Equation 9-4:

Equation 9-4
$$I_g = S_f \cdot I_f$$

Where:
  I_g = rms symmetrical grid current in amperes
  I_f = rms symmetrical ground fault current in amperes
  S_f = Fault current division factor

For the assumption of a sustained flow of the initial ground fault current, the symmetrical grid current can be expressed by Equation 9-5:

Equation 9-5
$$I_g = S_f \cdot (3I_0)$$

Where:
  I_o = Symmetrical rms value of Zero Sequence fault current in amperes

For transmission substations, calculate the maximum I_o for a single-phase-to-ground fault for both the present station configuration and the ultimate station configuration. Obtain values for all voltage levels in the station. Use the largest of these fault current values.

For distribution stations, since the fault current at distribution stations will not increase significantly over the life of the station as a result of the high impedance of the 34 and 69 kV feeders, the future fault current can be modeled using a suitable growth factor (suggest value of 1.1 x I_0).

For an extremely conservative design, the interrupting rating of the equipment can be used for I_0. This value may be as high as ten times the ultimate single-phase-to-ground fault current. Use of such a large safety factor in the initial design may make it difficult to design the grid to meet the tolerable touch and step voltage criteria by any means.

9.5.2 <u>Determine the Split Factor, S_f</u>

The split factor is used to take into account the fact that not all the fault current uses the earth as a return path. Some of the parameters that affect the fault current paths are:

  1. Location of the fault
  2. Magnitude of substation ground grid impedance
  3. Buried pipes and cables in the vicinity of or directly connected to the substation ground system
  4. Overhead ground wires, neutrals, or other ground return paths

The most accurate method for determining the percentage of the total fault current that flows into the earth is to use a computer program such as EPRI's SMECC, Substation Maximum Earth Current Computation. This program and similar programs, however, require an involved data collection effort. For the purposes of this Bulletin, the graphical method will be used.

Two types of graphs will be presented:

1. 100 percent remote, 0 percent local fault current contribution
2. 25, 50, and 75 percent local, which corresponds to 75, 50, and 25 percent remote fault current contribution

Figures 9-6 through 9-21 are for 100 percent remote, 0 percent local fault current contribution. These represent typical distribution substations with delta-wye grounded transformers, switching stations, and transmission stations with no local sources of zero-sequence current. Each of these graphs contains a number of curves representing various combinations of transmission lines and feeders at the substation.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 15 OHMS   DIST. GND - 25 OHMS

Figure 9-6: Approximate Split Factor S_f 100% Remote, 1 Transmission Line,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C1. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

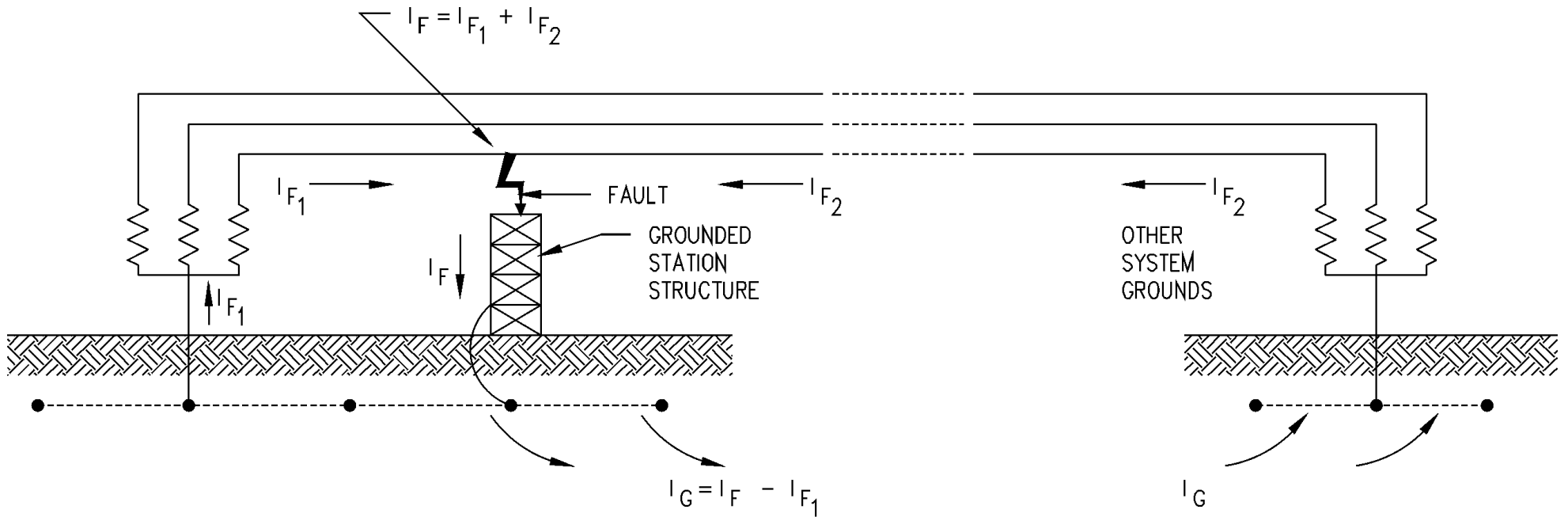### 100% REMOTE CONTRIBUTION

TRANS. GND - 100 OHMS   DIST. GND - 200 OHMS

Figure 9-7: Approximate Split Factor S_f 100% Remote, 1 Transmission Line,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C2. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 15 OHMS   DIST. GND - 25 OHMS

Figure 9-8: Approximate Split Factor S$_f$ 100% Remote, 2 Transmission Lines,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C3. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 100 OHMS   DIST. GND - 200 OHMS

Figure 9-9: Approximate Split Factor S_f 100% Remote, 2 Transmission Lines,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C4. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 15 OHMS   DIST. GND - 25 OHMS

Figure 9-10: Approximate Split Factor S_f 100% Remote, 4 Transmission Lines,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C5. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

Figure 9-11: Approximate Split Factor S $_f$ 100% Remote, 4 Transmission Lines,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C6. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

Figure 9-12: Approximate Split Factor S $_f$ 100% Remote, 8 Transmission Lines,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C7. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION
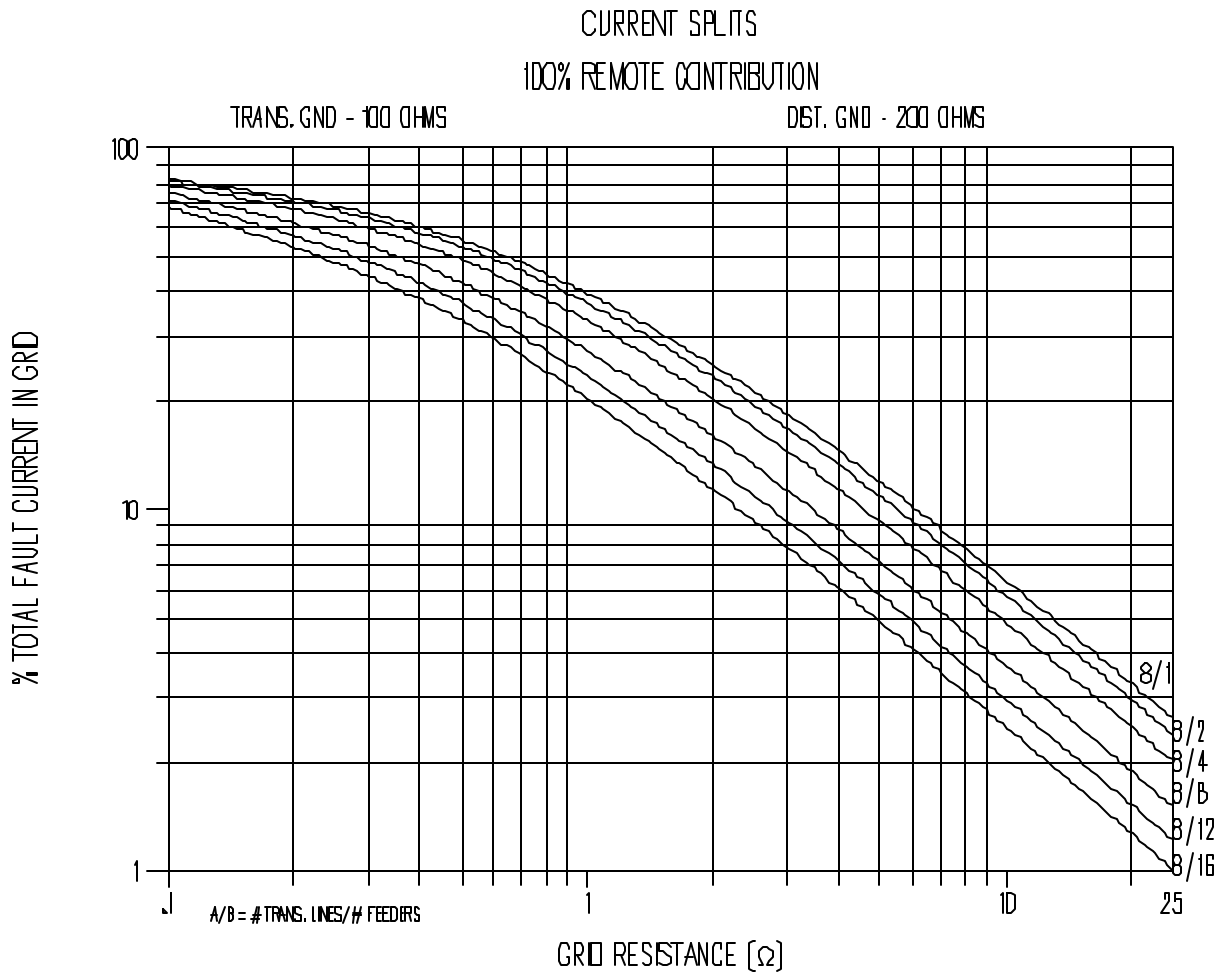
Figure 9-13: Approximate Split Factor S $_f$ 100% Remote, 8 Transmission Lines,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C8. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 15 OHMS   DIST. GND - 25 OHMS

Figure 9-14: Approximate Split Factor S $_f$ 100% Remote, 12 Transmission Lines,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C9. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS GND - 15 OHMS   DIST. GND - 25 OHMS

Figure 9-15: Approximate Split Factor S $_f$ 100% Remote, 12 Transmission Lines,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C10. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS GND - 15 OHMS   DIST. GND - 25 OHMS
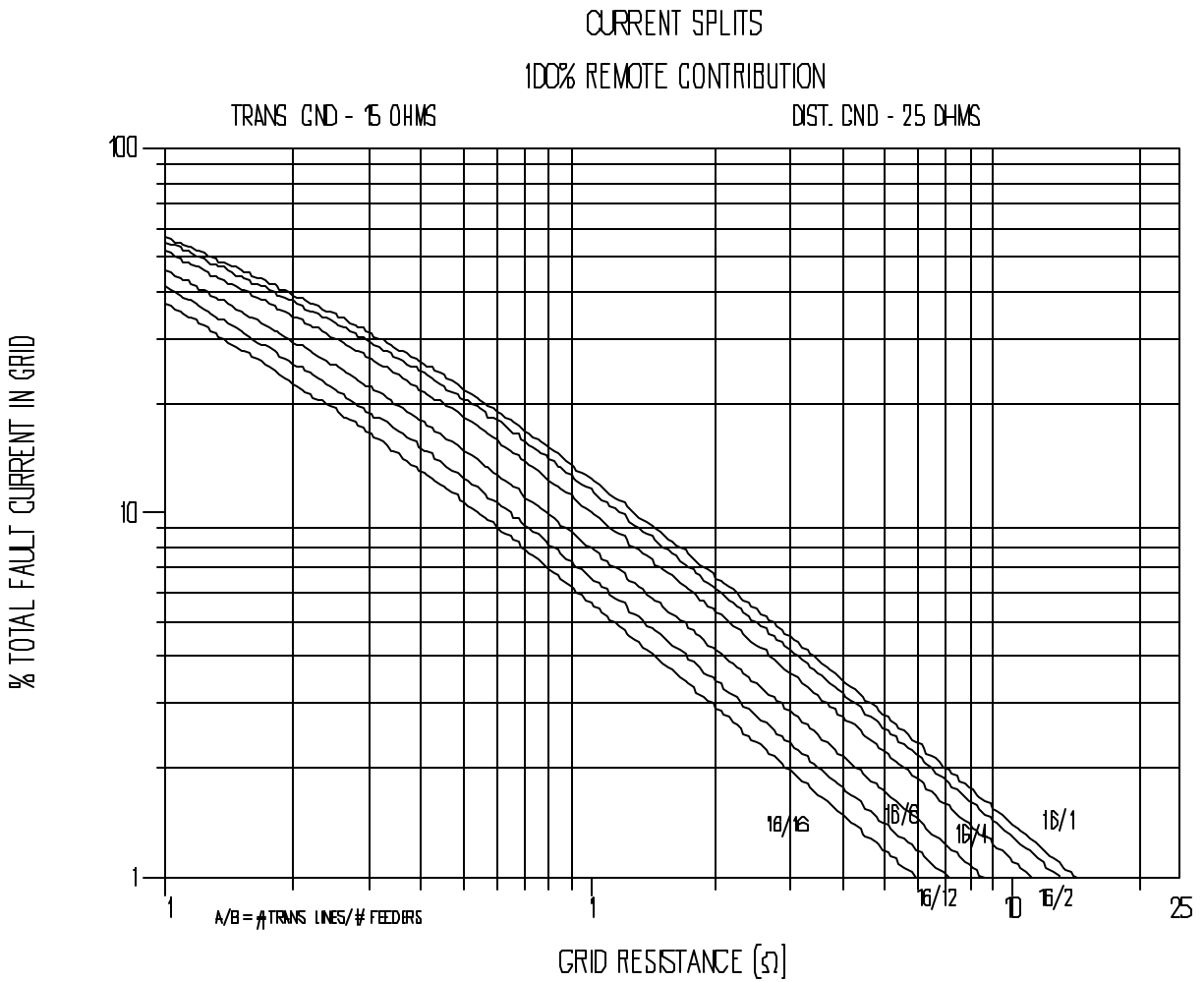
Figure 9-16: Approximate Split Factor S $_f$ 100% Remote, 16 Transmission Lines,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C11. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS. GND - 100 OHMS   DIST. GND - 200 OHMS
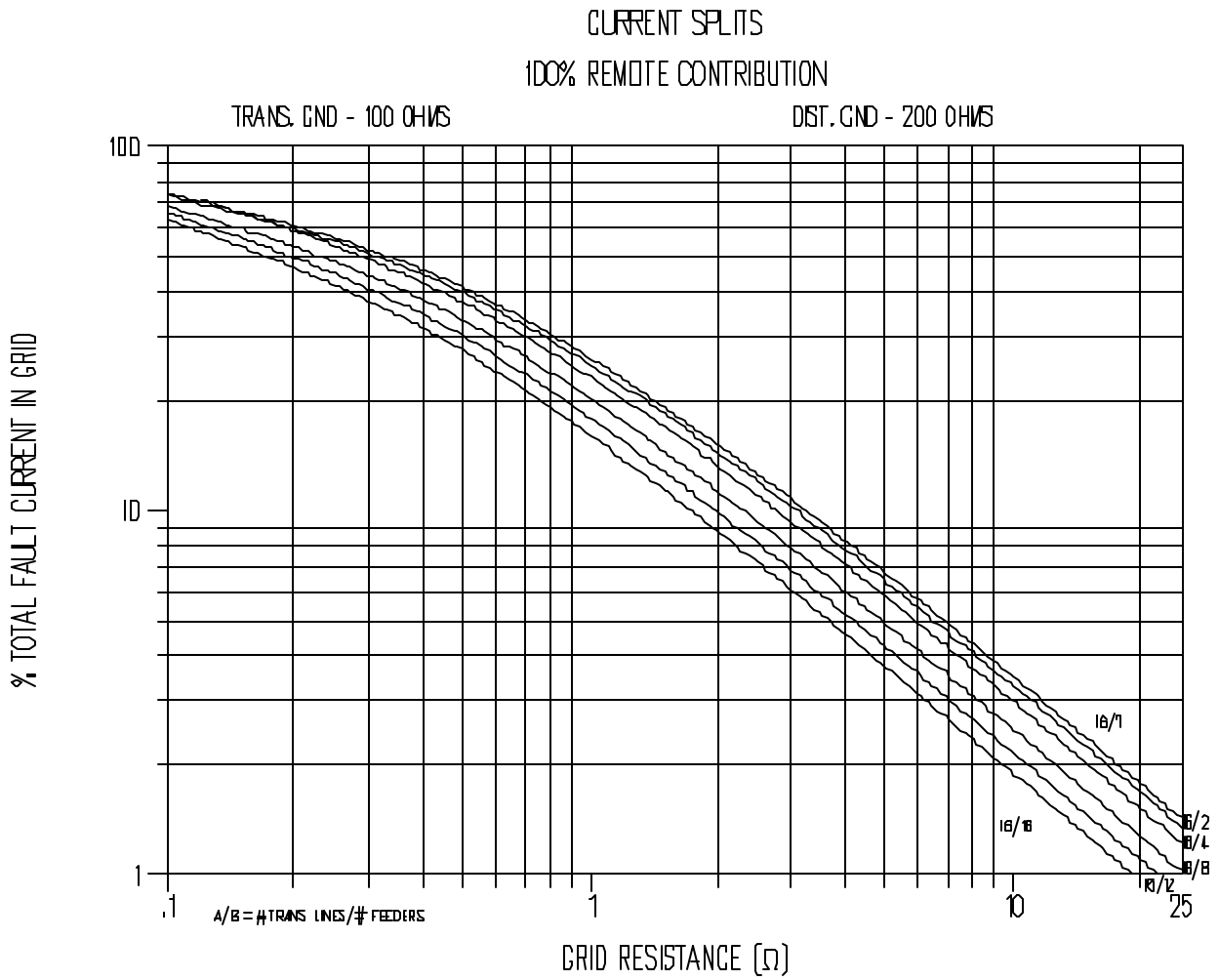
Figure 9-17: Approximate Split Factor S $_f$ 100% Remote, 16 Transmission Lines,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C12. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

TRANS GND - 15 OHMS   NO FEEDERS
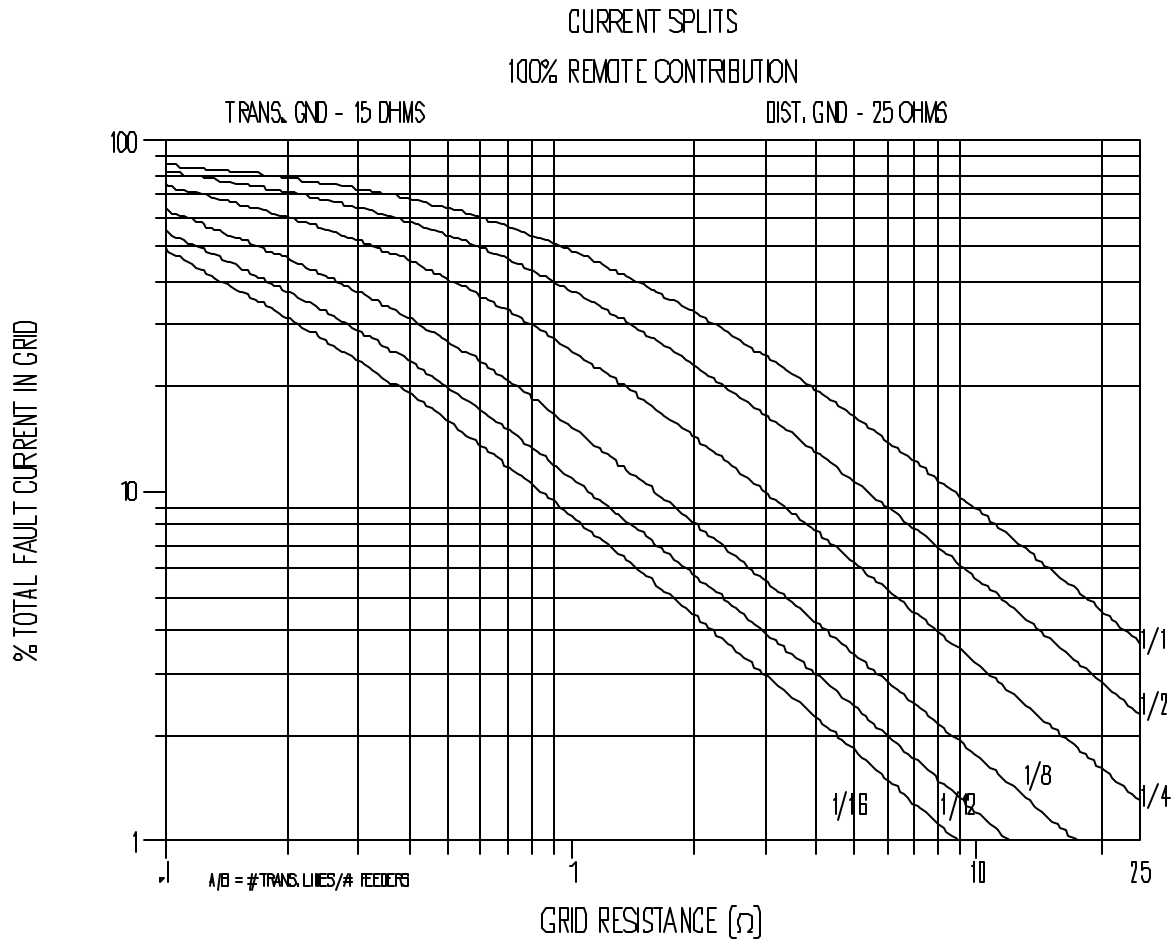

A/B = # TRANS LINES / # FEEDERS

GRID RESISTANCE (Ω)

Figure 9-18: Approximate Split Factor S $_f$ 100% Remote, No Feeder,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C13. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION
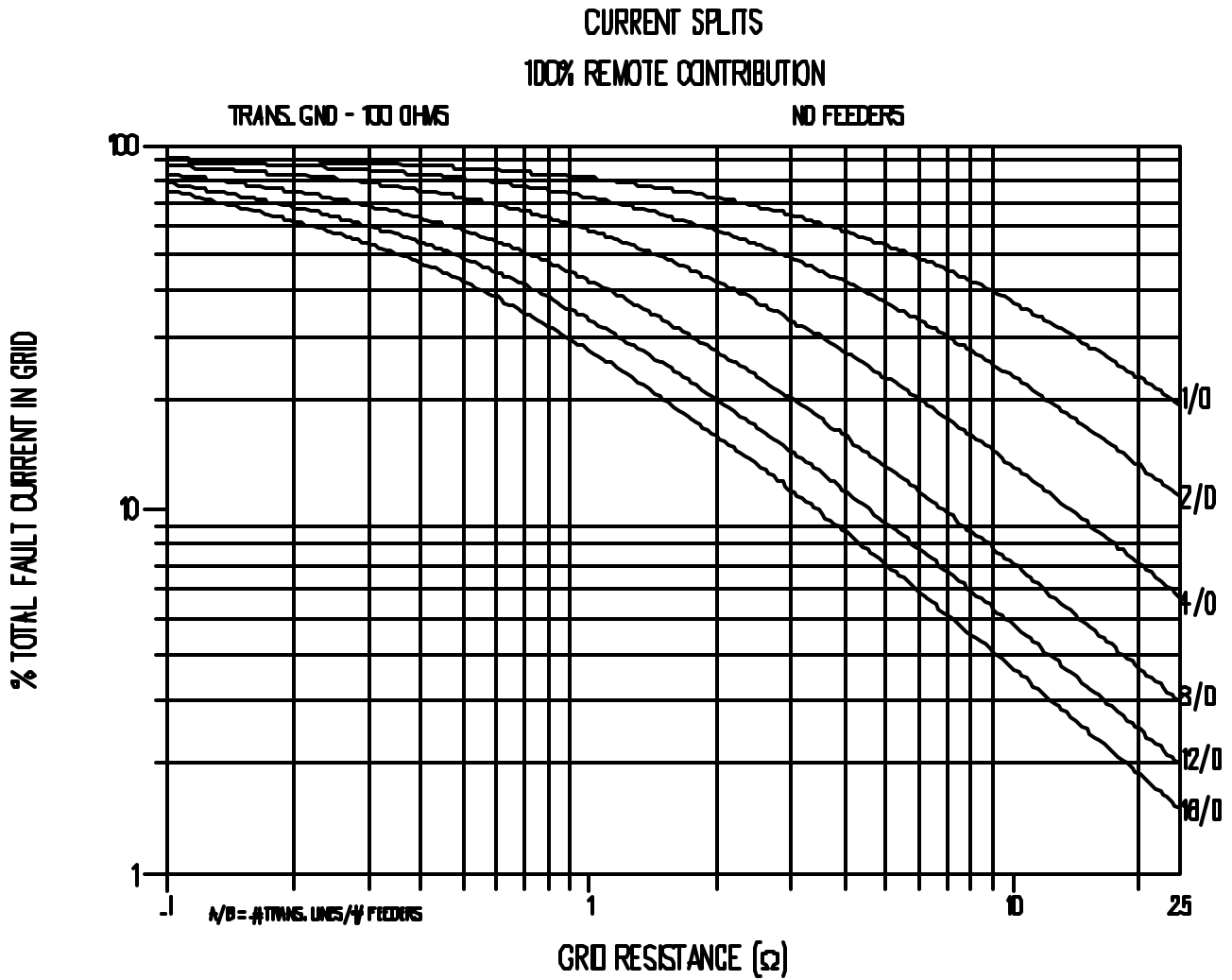
Figure 9-19: Approximate Split Factor S$_f$ 100% Remote, No Feeder,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C14. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

NO TRANS. LINE SHIELD WIRE   DIST GND - 25 OHMS
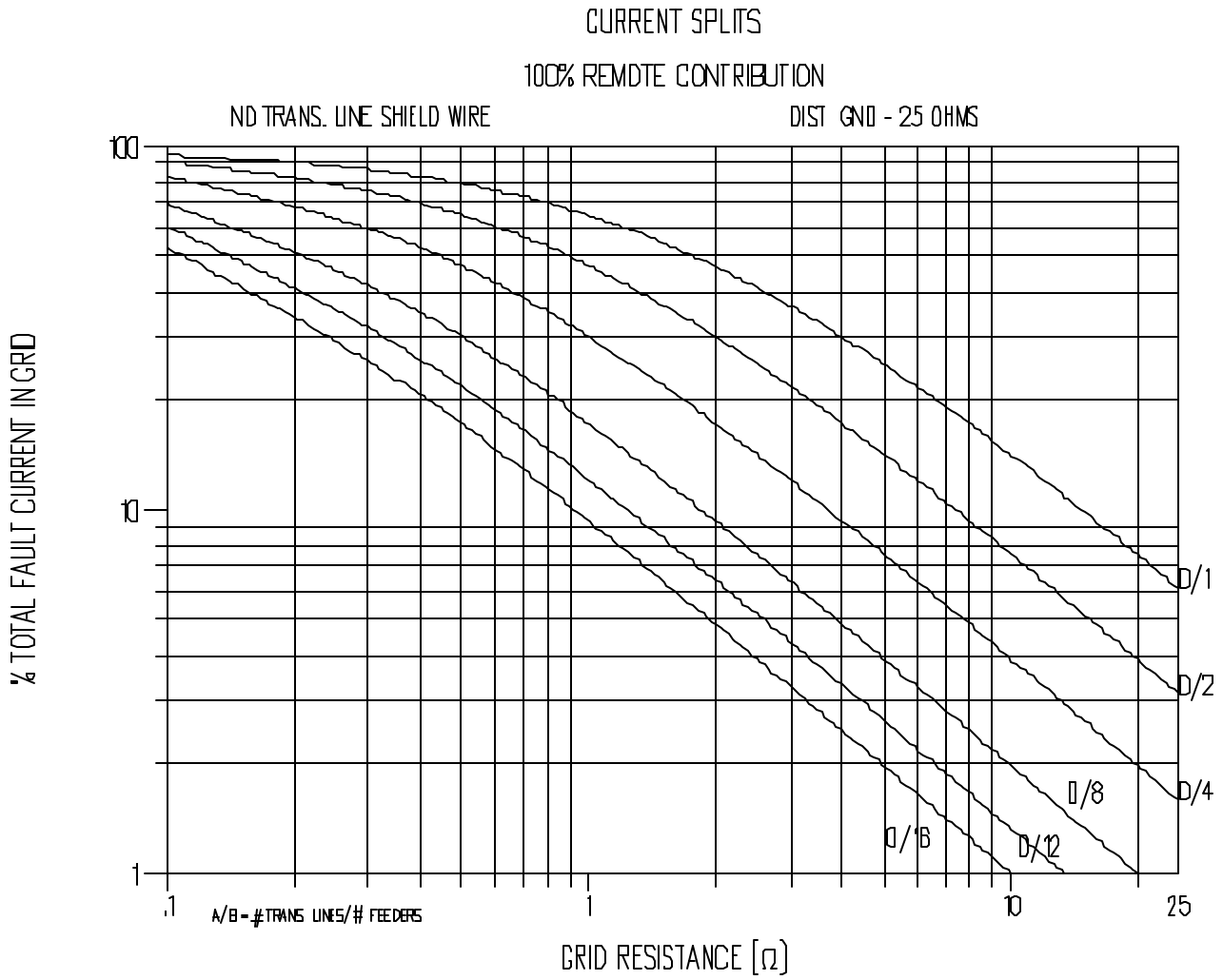
Figure 9-20: Approximate Split Factor S $_f$ 100% Remote, No Transmission Line,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
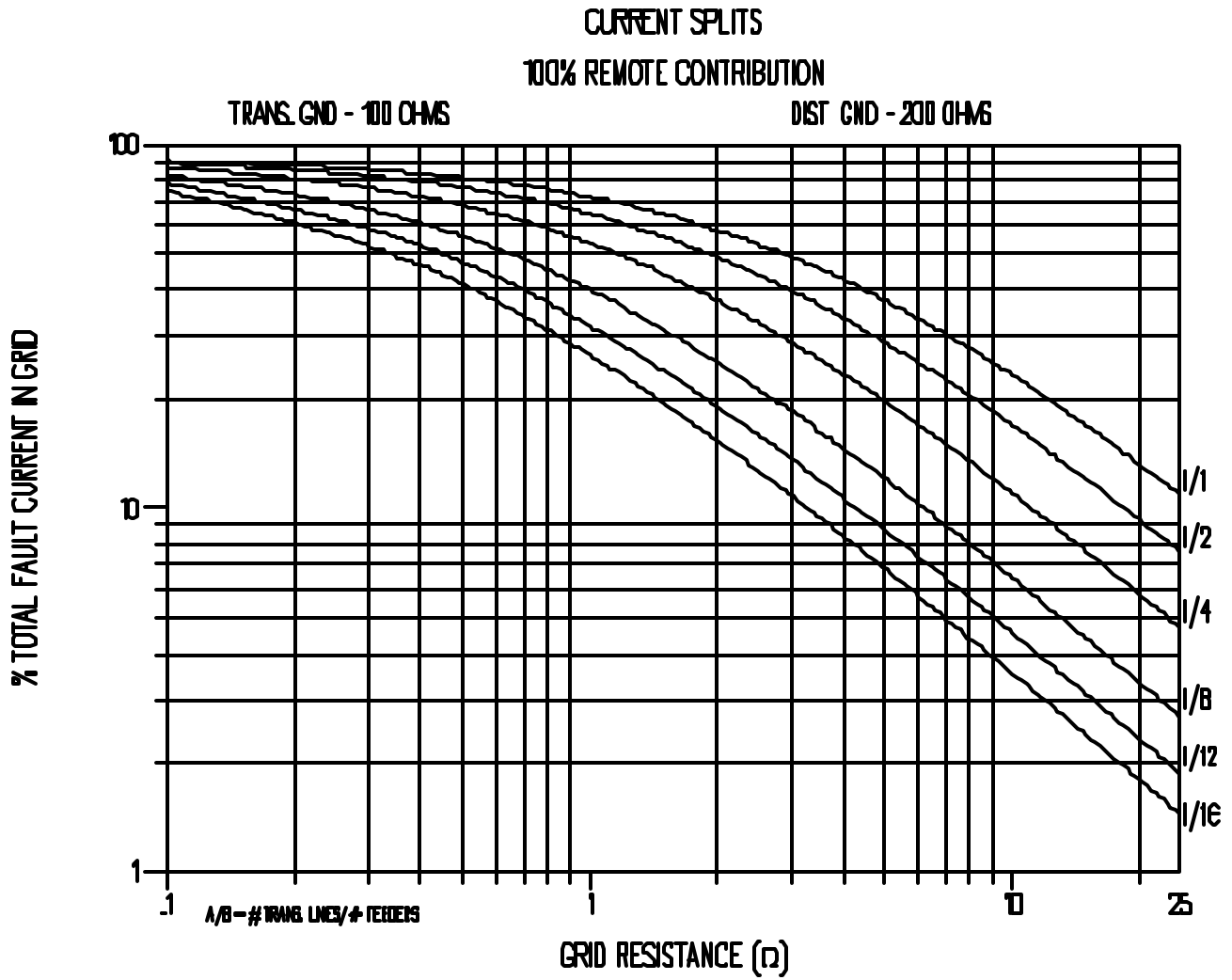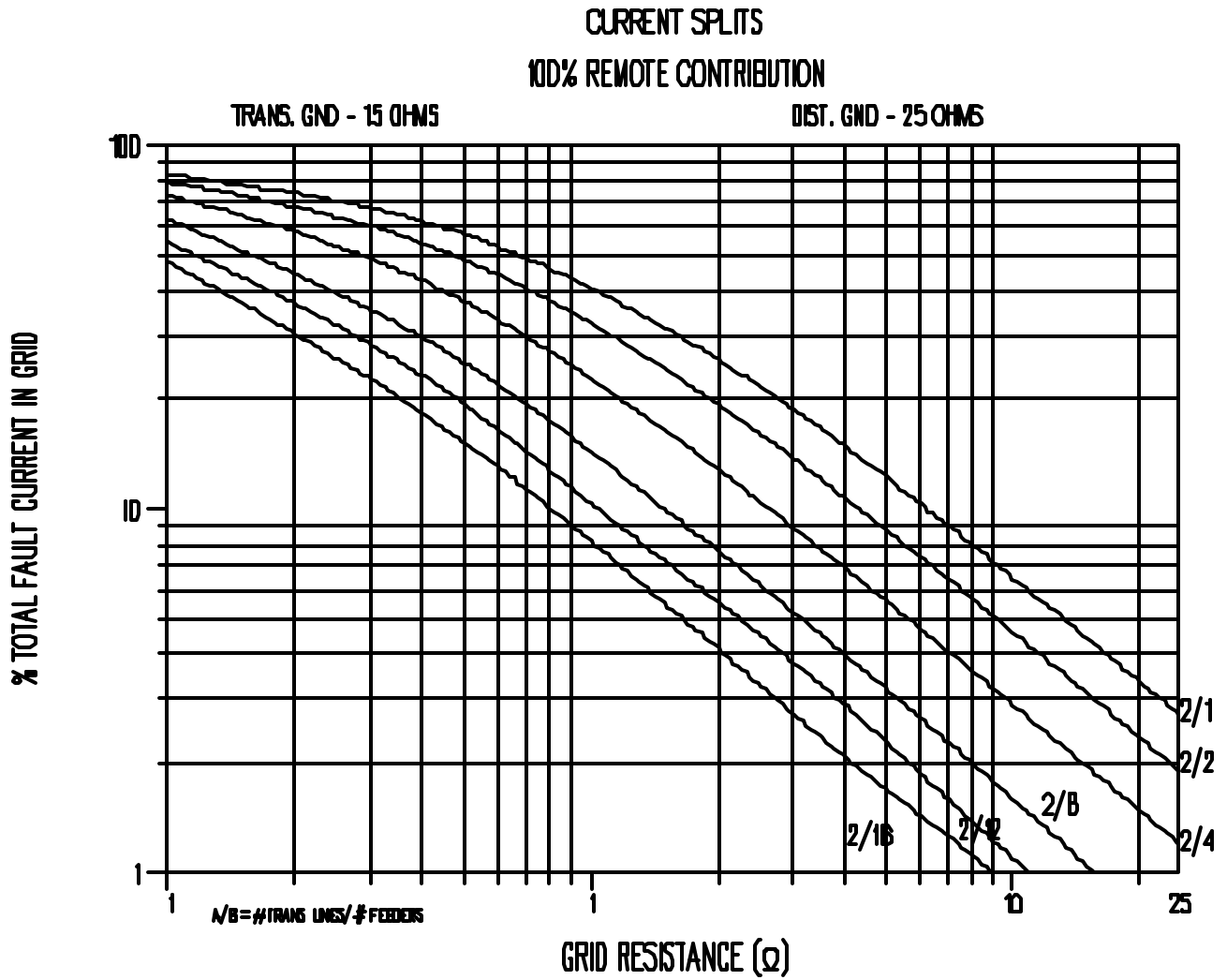Figure C15. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

100% REMOTE CONTRIBUTION

NO TRANS. LINE SHIELD WIRE   DIST. GND - 200 OHMS

(Graph: Y-axis labeled "% TOTAL FAULT CURRENT IN GRID", with values 100, 10, 1. X-axis labeled "GRID RESISTANCE (Ω)", with values 1, 1, 10, 25. Curves labeled 0/1, 0/2, 0/4, 0/8, 0/12, 0/16. Note at bottom: A/B=# TRANS. LINES/# FEEDERS)
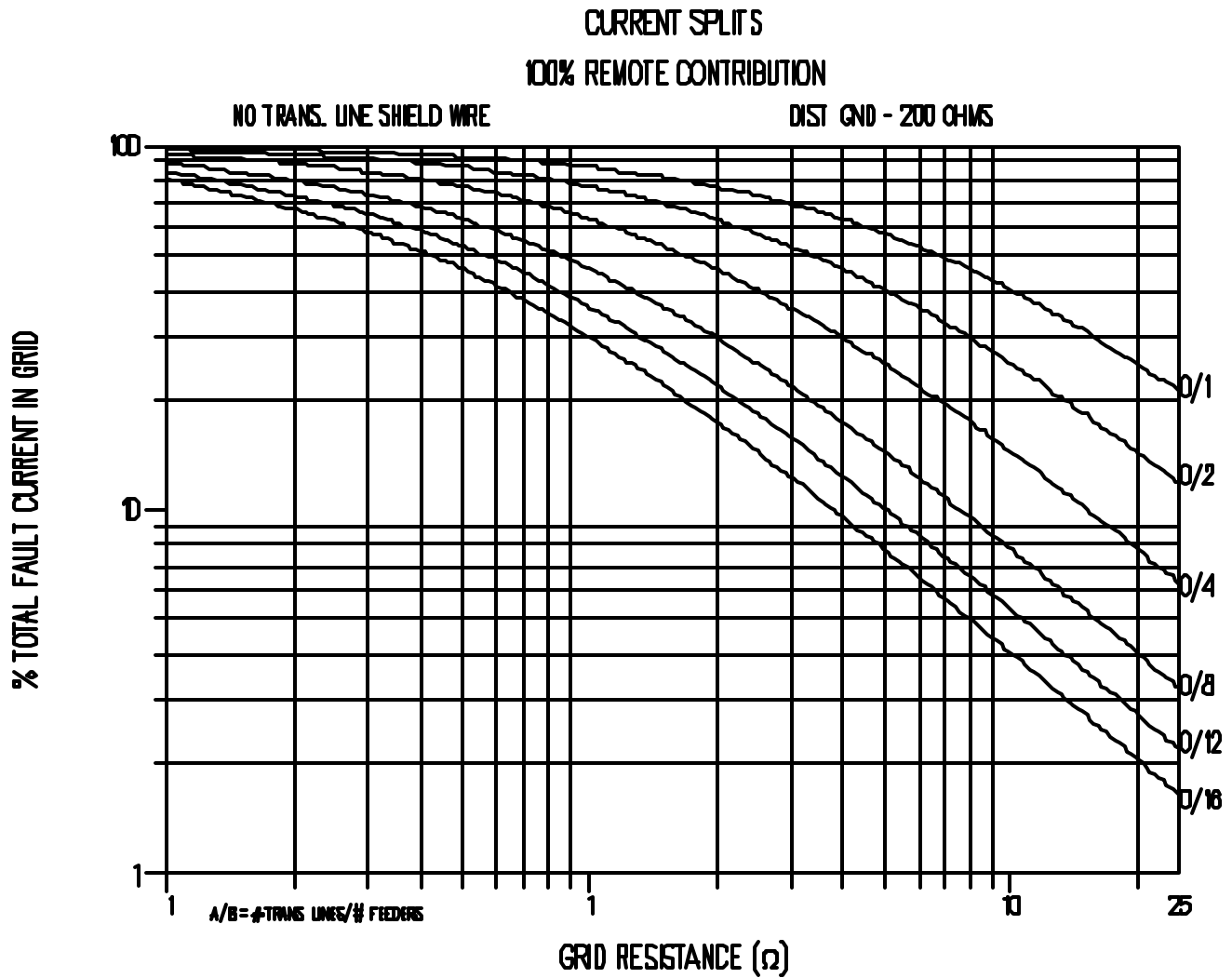
Figure 9-21: Approximate Split Factor S $_f$ 100% Remote, No Transmission Line,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
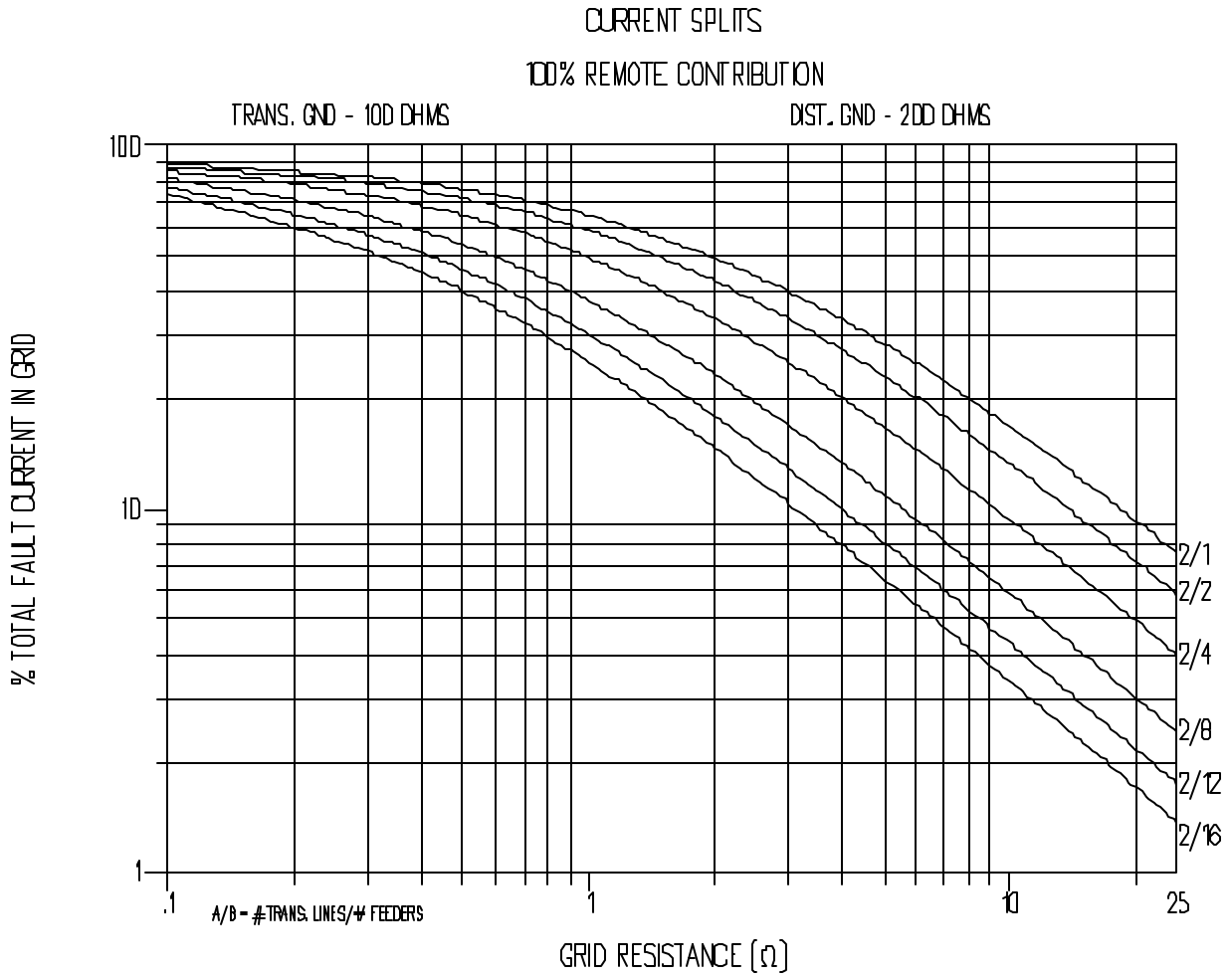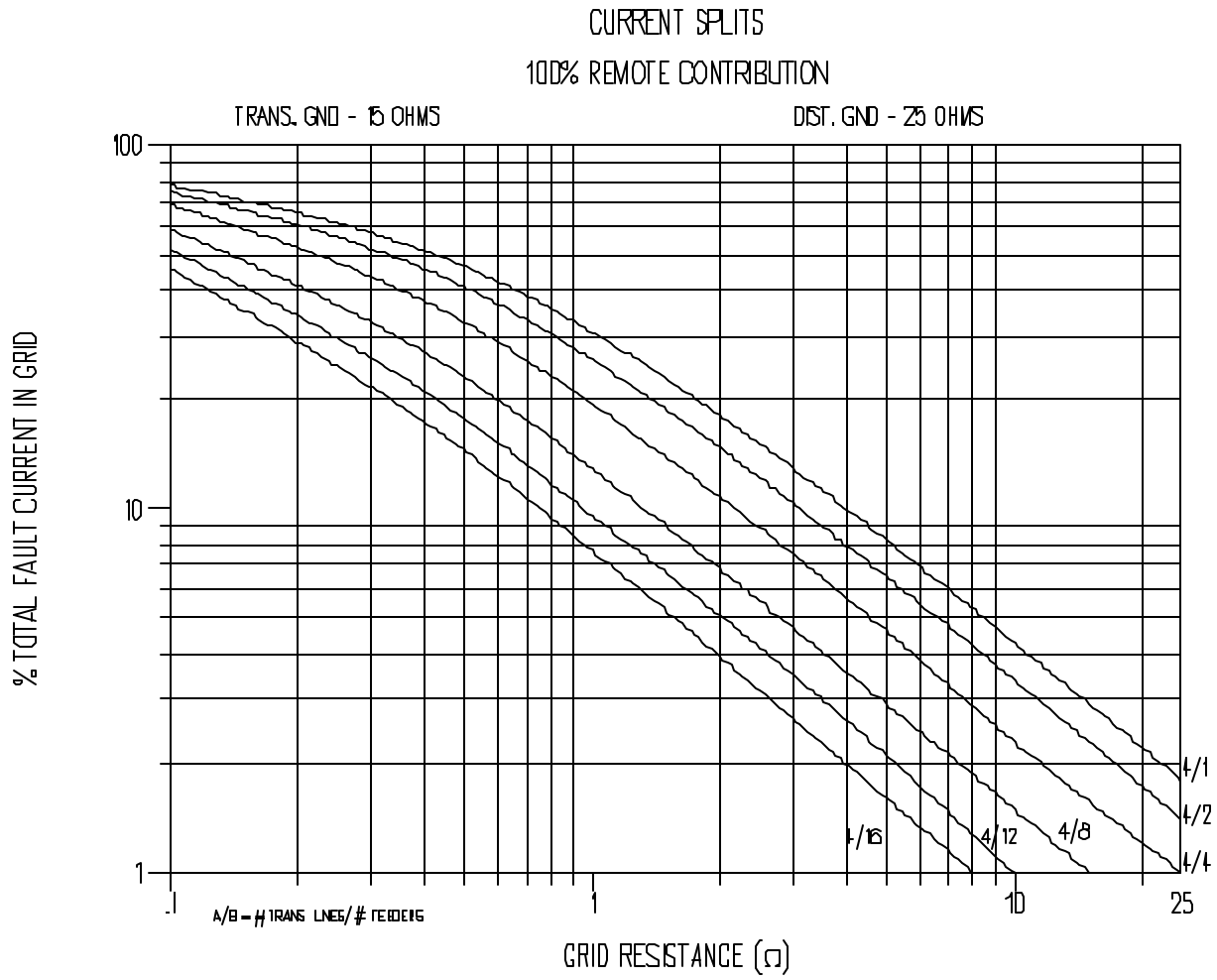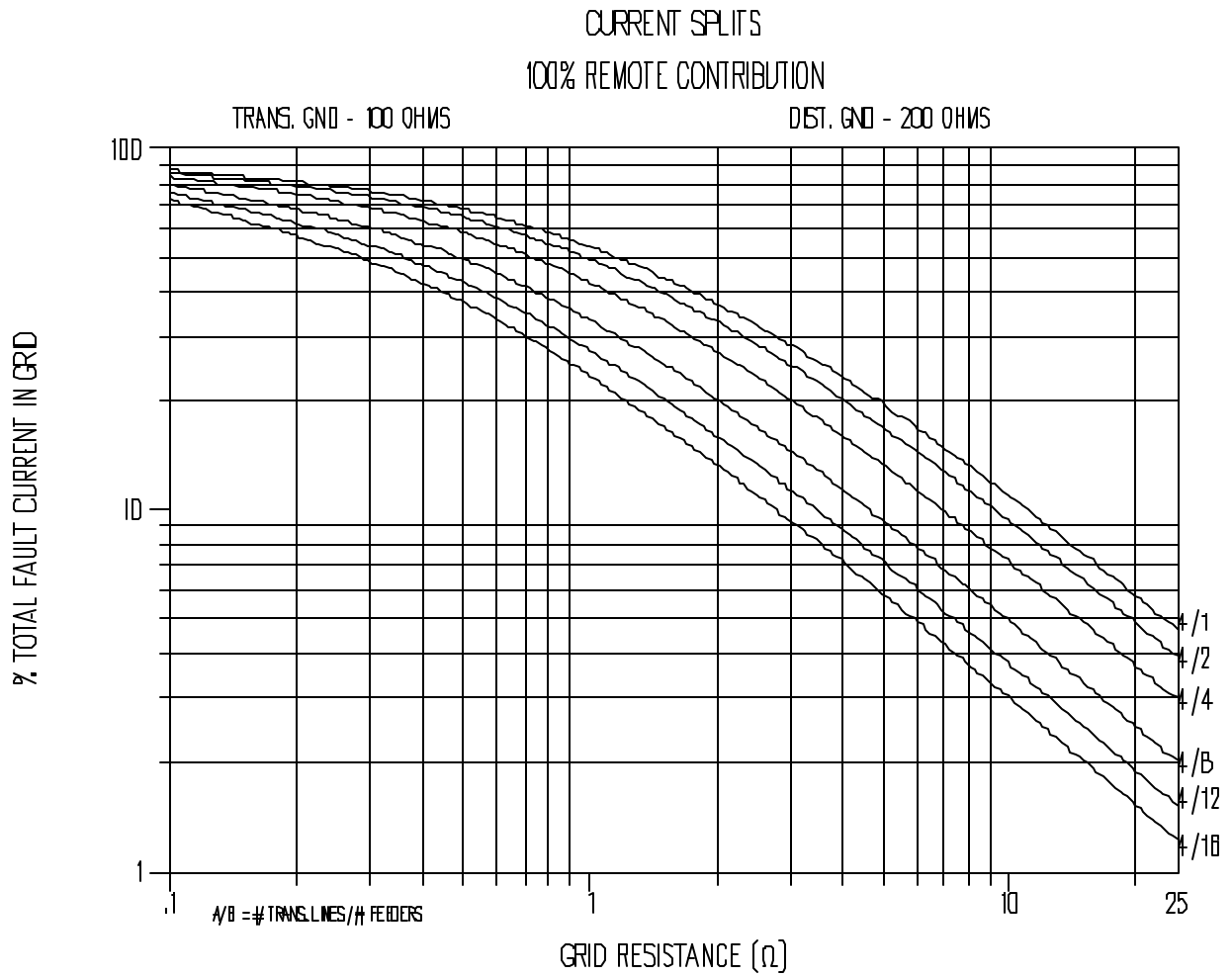Figure C16. Copyright © 1998. IEEE. All rights reserved.

Figures 9-22 through 9-27 are for 25, 50, and 75 percent local, which correspond to 75, 50, and 25 percent remote fault current contribution. This represents typical transmission substations or generating stations with X number of transmission lines (feeders are considered transmission lines on this graph). These stations contain local sources of zero-sequence current such as autotransformers and grounded-wye generator step-up transformers. The greater the local contribution, the lower the earth current since the locally contributed fault current usually has a direct conductive path to the system neutral.

CURRENT SPLITS

25% LOCAL; 75% REMOTE CONTRIBUTIONS

TRANS. GND - 15 OHMS   NO FEEDERS

% TOTAL FAULT CURRENT IN GRID

A/B = # TRANS LINES / # FEEDERS
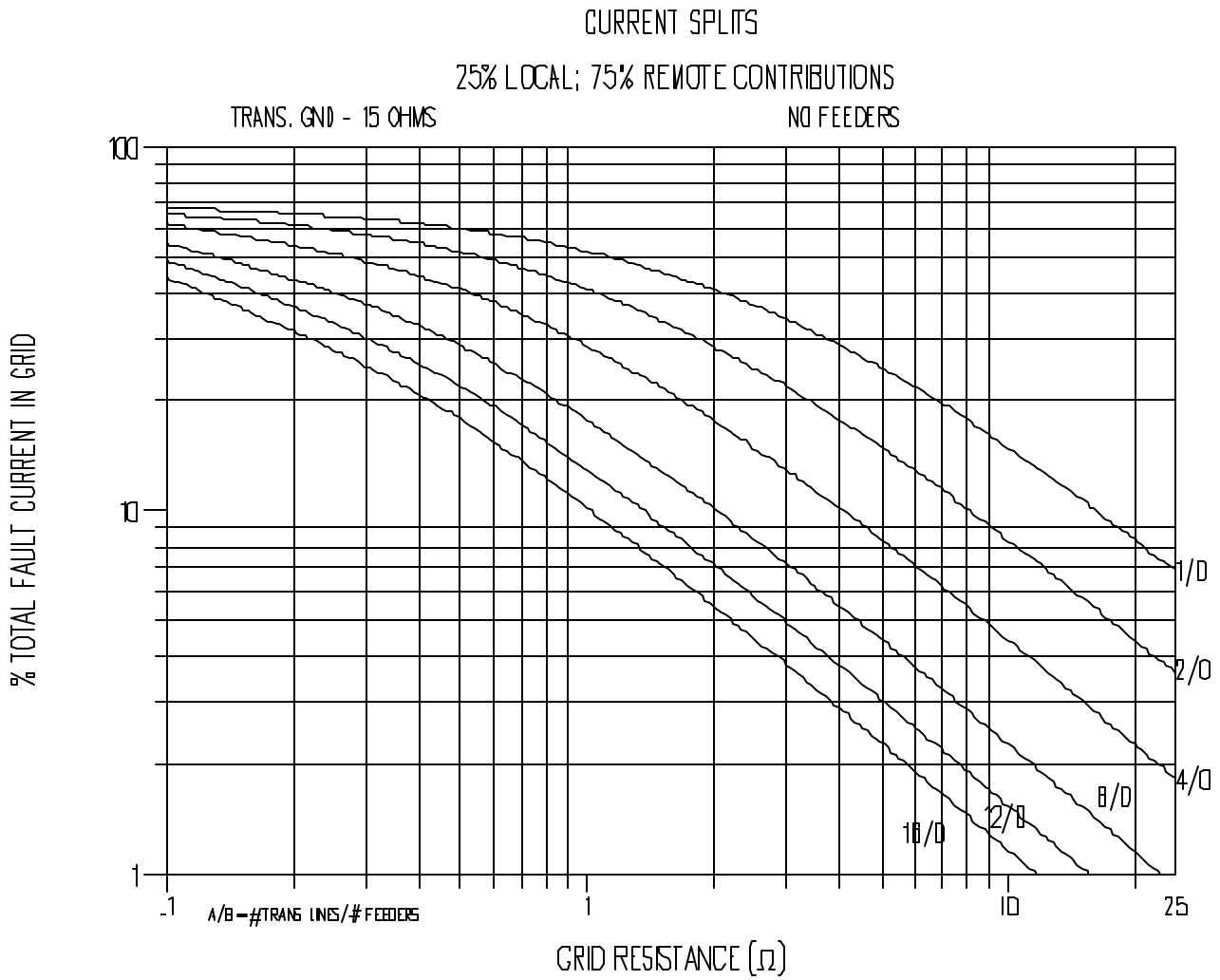
GRID RESISTANCE (Ω)

Figure 9-22: Approximate Split Factor S_f 75% Remote, No Feeder,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
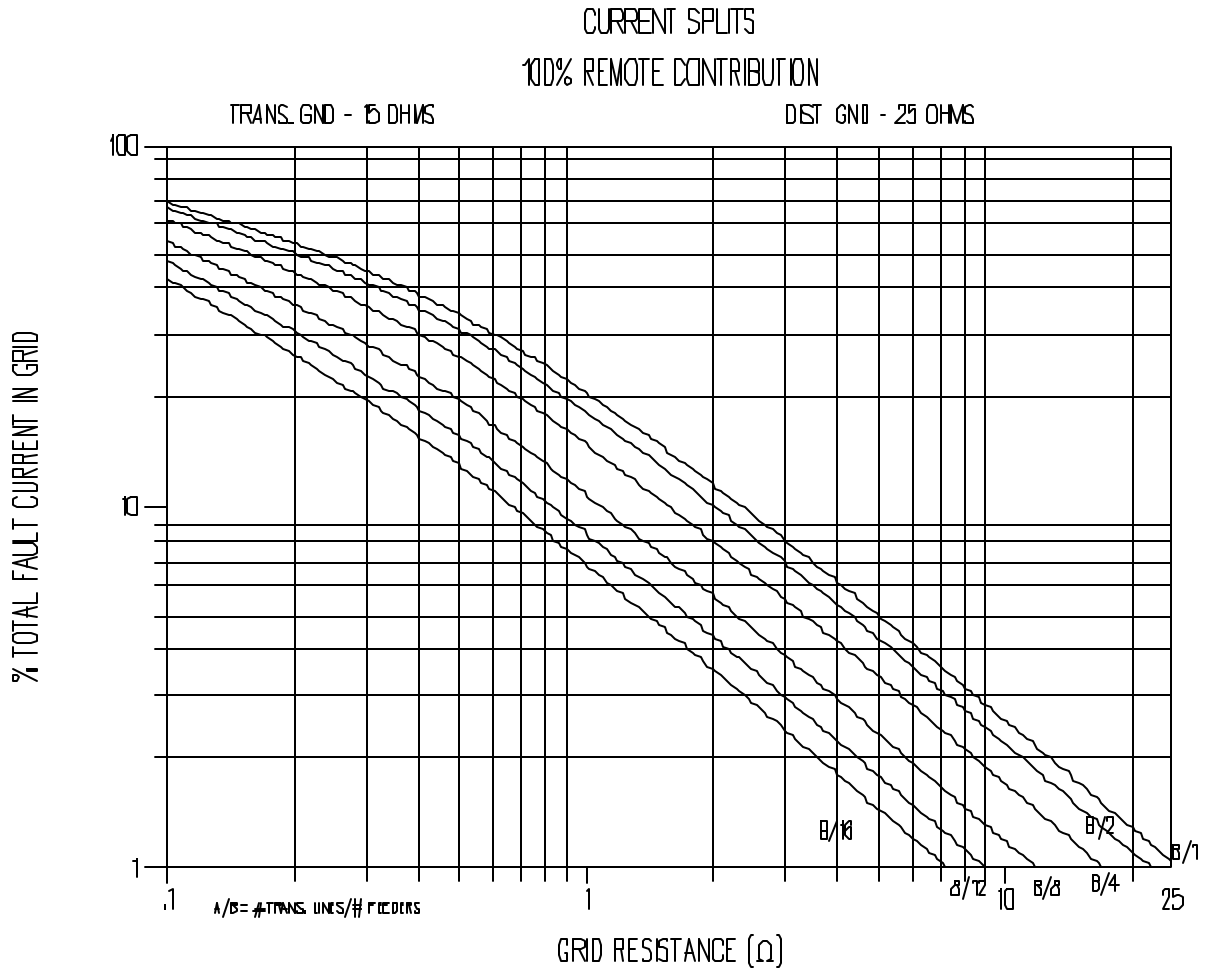Figure C17. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

25% LOCAL, 75% REMOTE CONTRIBUTIONS

TRANS. GND - 100 OHMS   NO FEEDERS
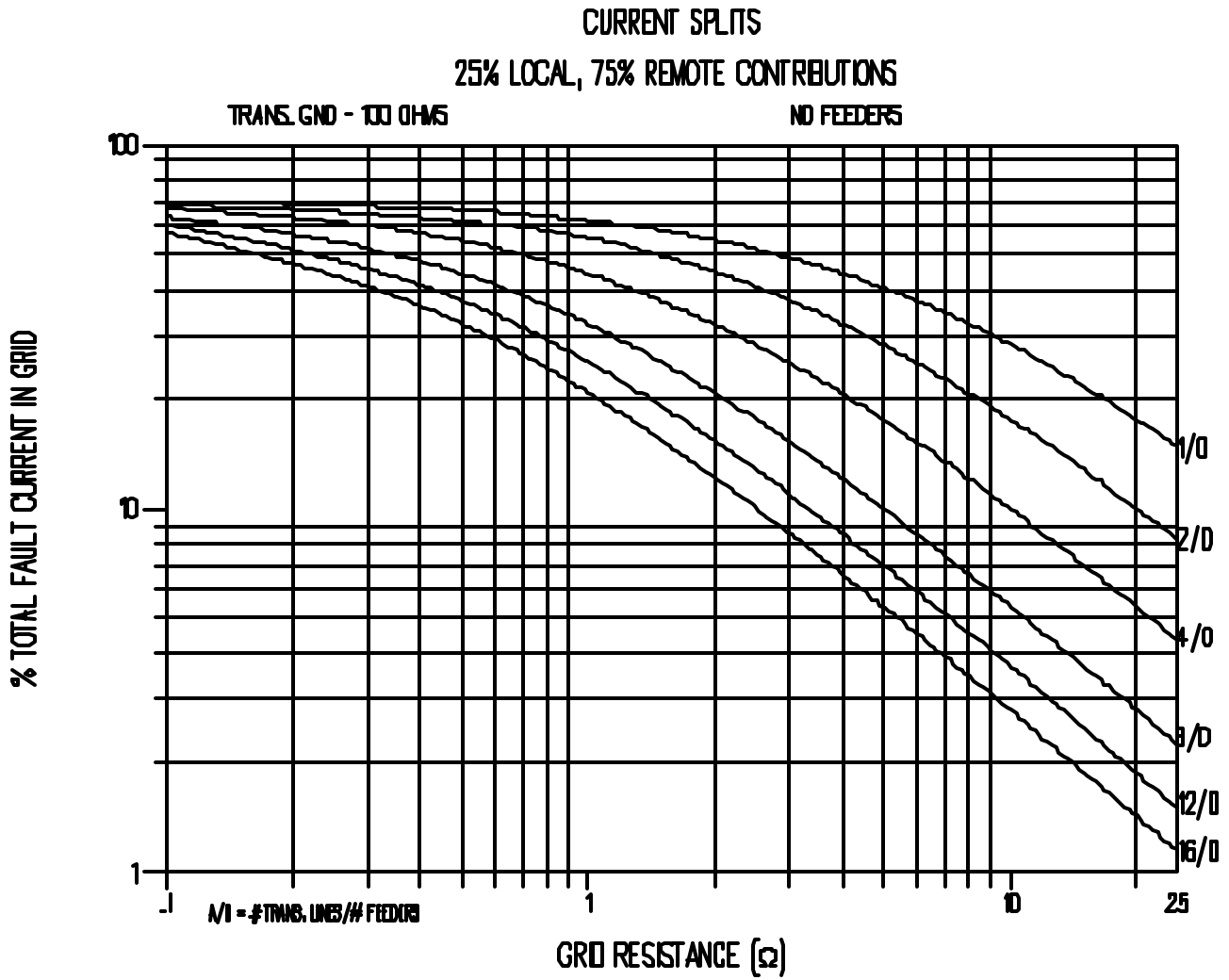
Figure 9-23: Approximate Split Factor S_f 75% Remote, No Feeder,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C18. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

50% LOCAL; 50% REMOTE CONTRIBUTIONS

TRANS GND — 15 OHMS   NO FEEDERS

A/B=#TRANS LINES/# FEEDERS
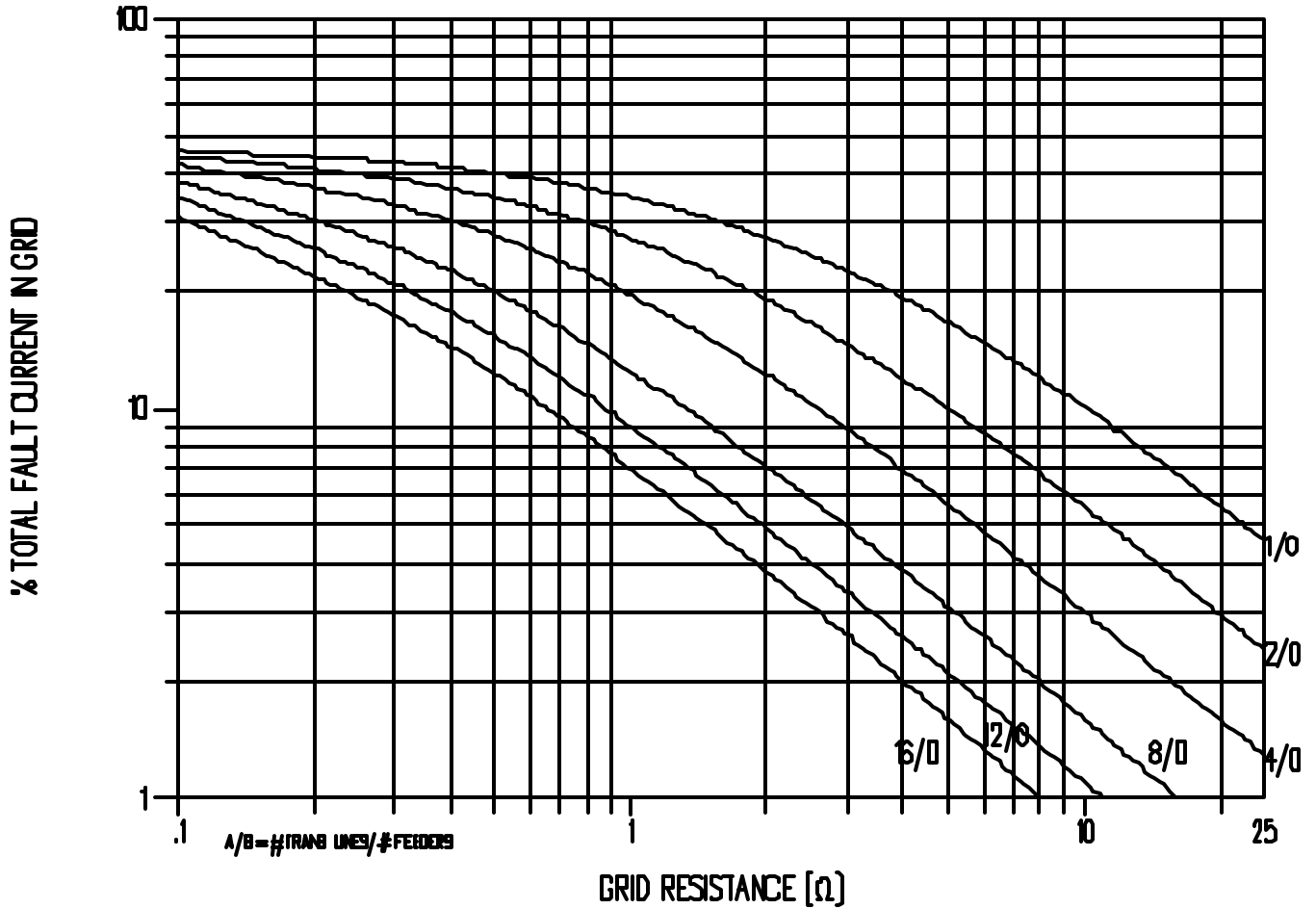
GRID RESISTANCE [Ω]

Figure 9-24: Approximate Split Factor S_f 50% Remote, No Feeder,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
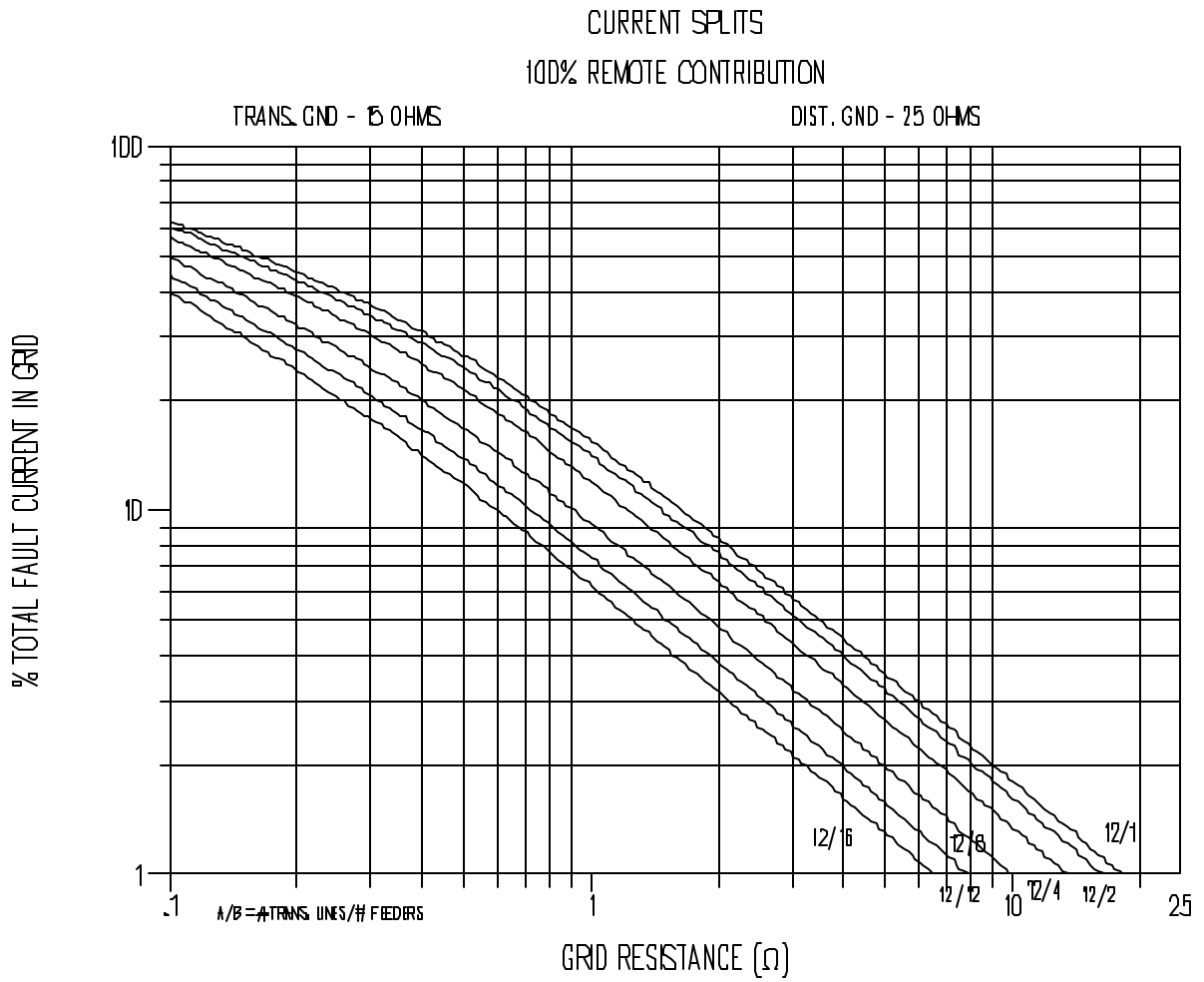Figure C19. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS
50% LOCAL; 50% REMOTE CONTRIBUTIONS

TRANS GND - 100 OHMS   NO FEEDERS
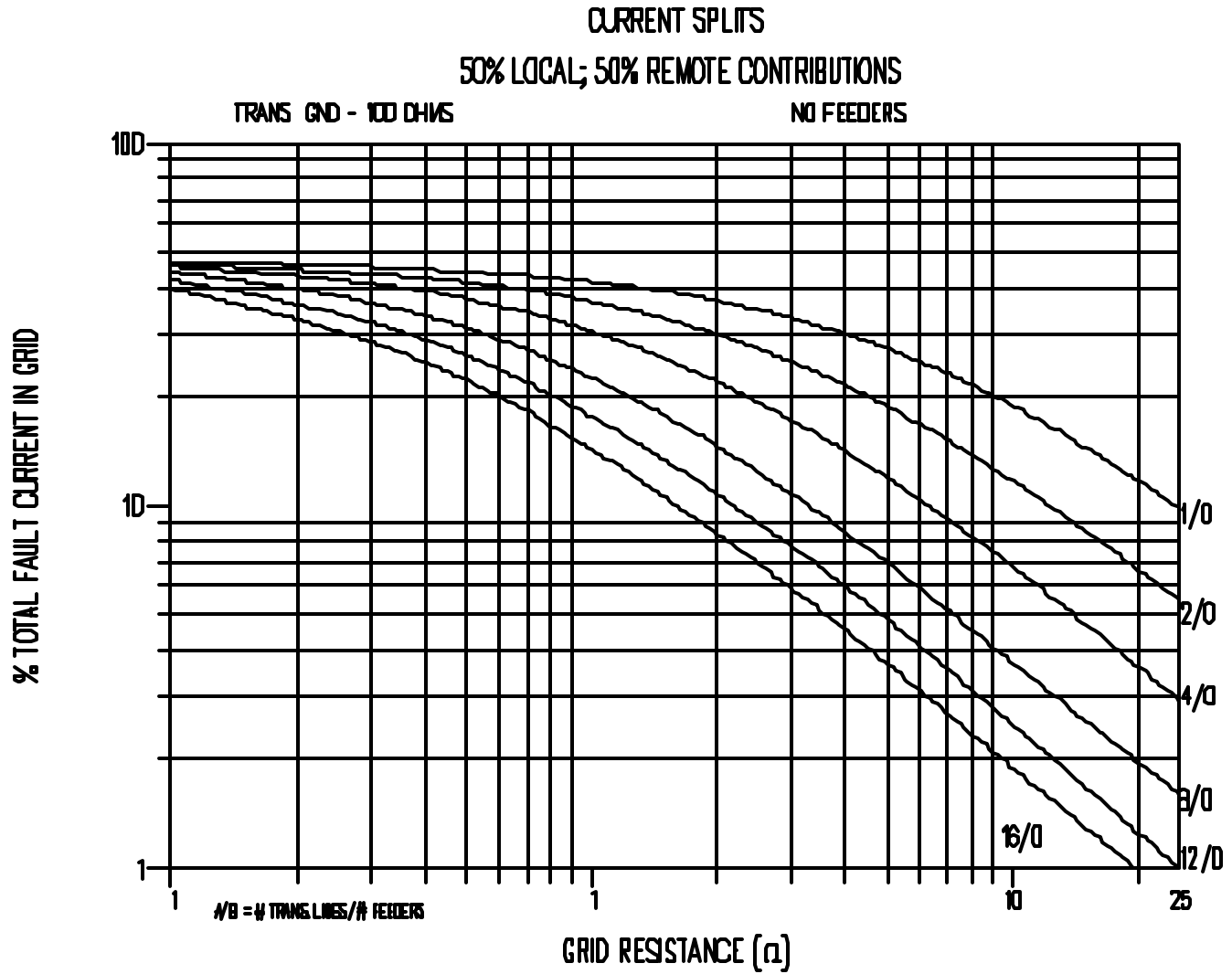
Figure 9-25: Approximate Split Factor S_f 50% Remote, No Feeder,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C20. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS

75% LOCAL; 25% REMOTE CONTRIBUTIONS

TRANS. GND – 15 OHMS   NO FEEDERS
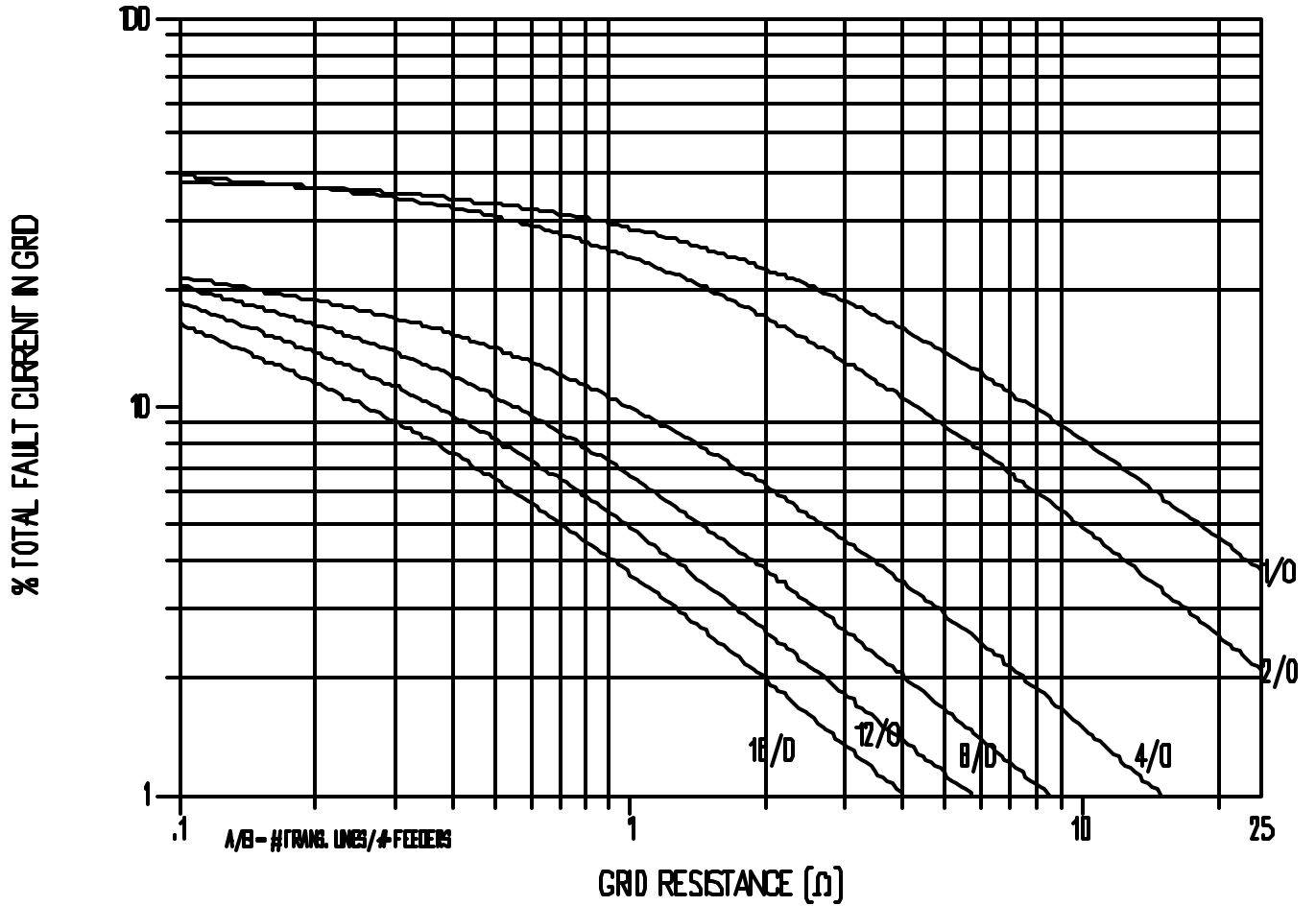
Figure 9-26: Approximate Split Factor S_f 25% Remote, No Feeder,
Low Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
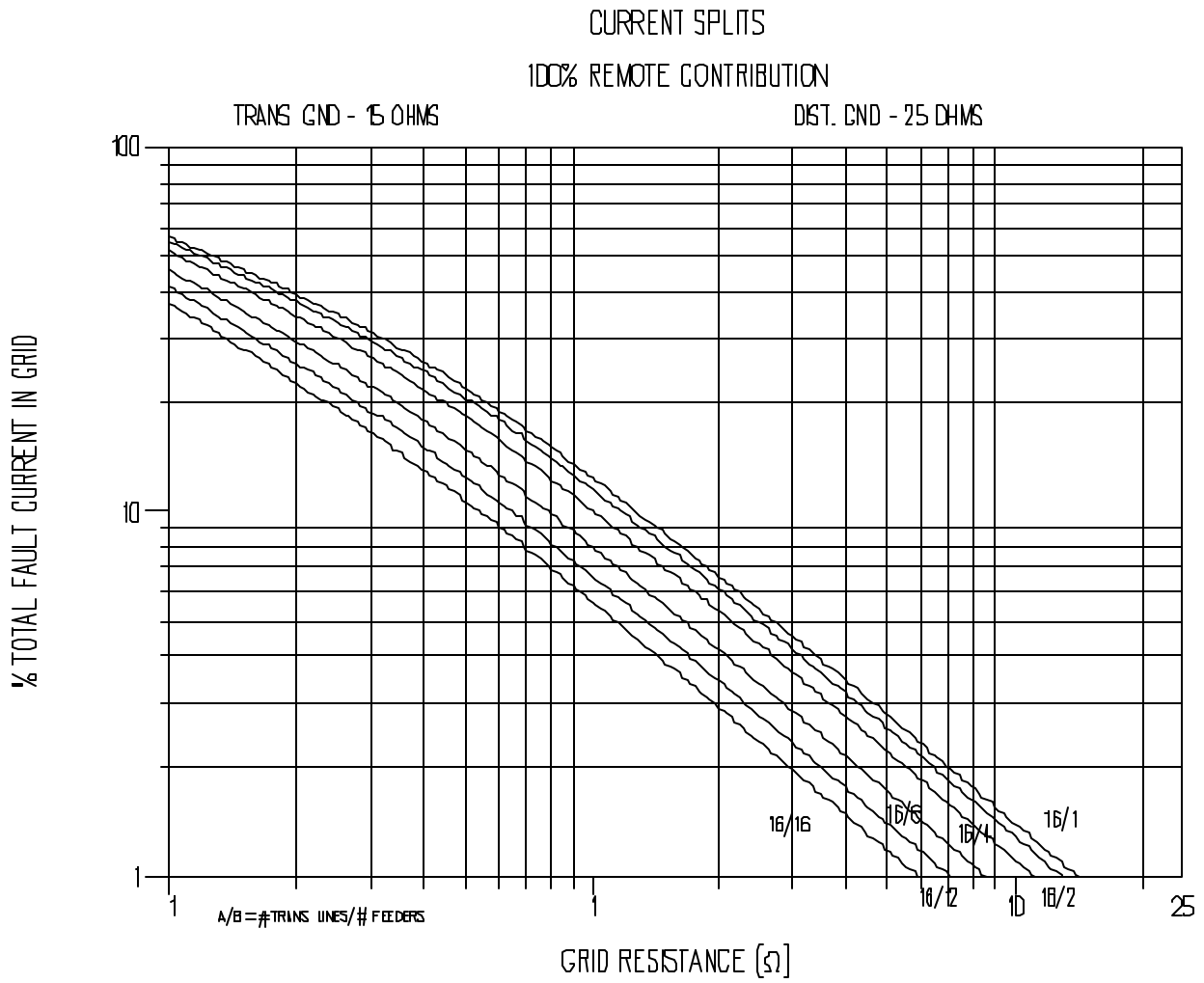Figure C21. Copyright © 1998. IEEE. All rights reserved.

CURRENT SPLITS
75% LOCAL; 25% REMOTE CONTRIBUTIONS

TRANS. GND - 100 OHMS   NO FEEDERS
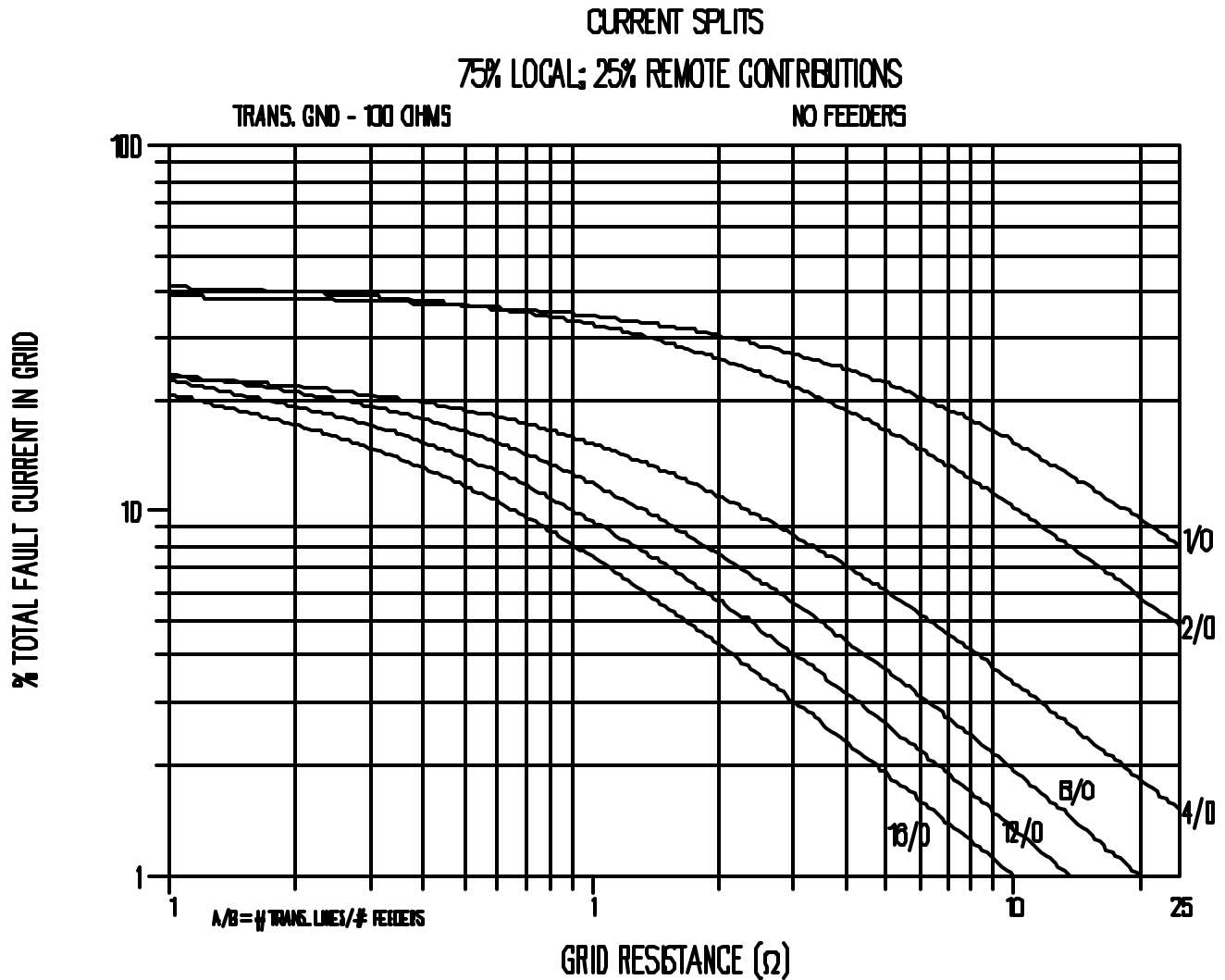
Figure 9-27: Approximate Split Factor S_f 25% Remote, No Feeder,
High Line Ground Resistance. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure C22. Copyright © 1998. IEEE. All rights reserved.

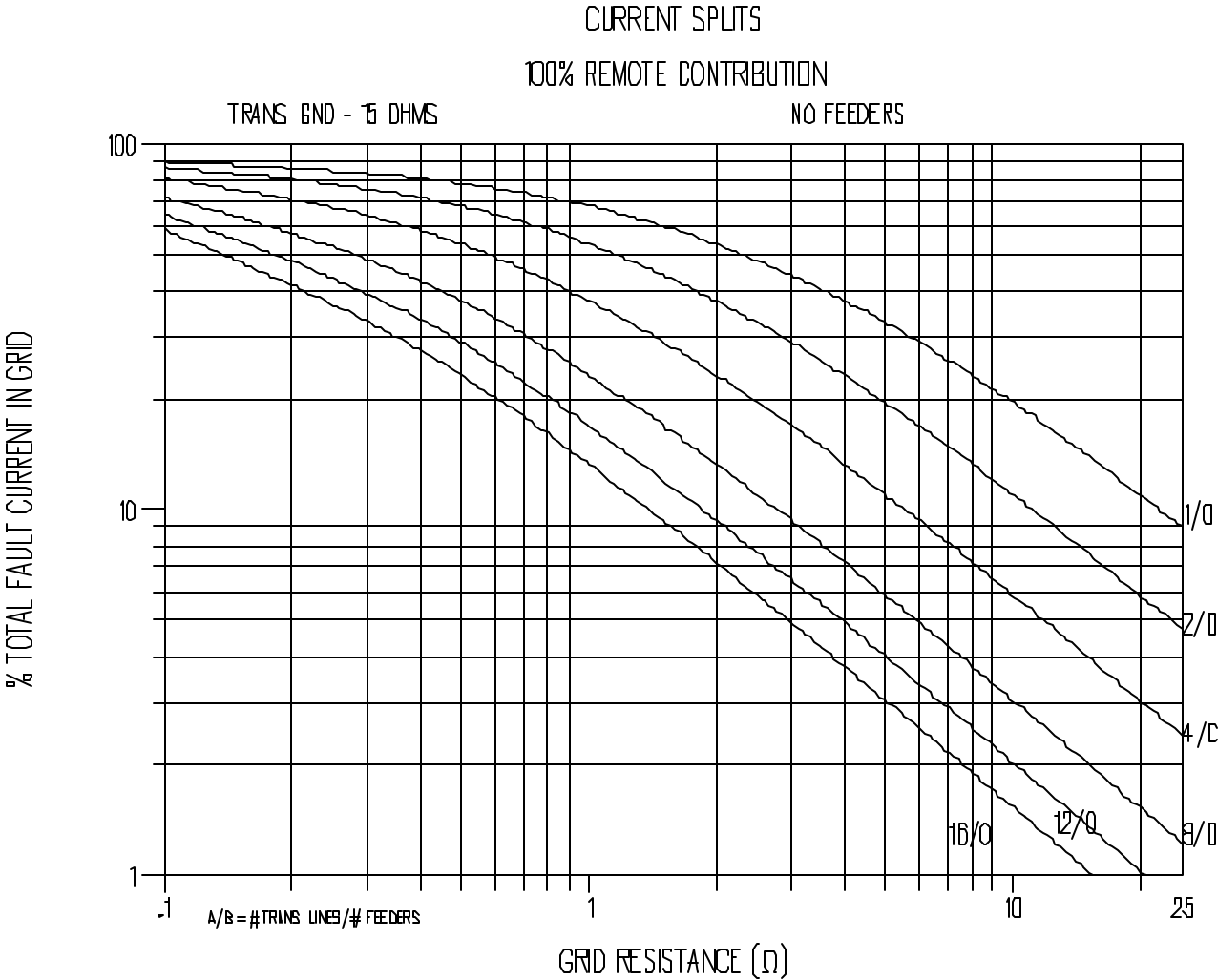In calculating the number of transmission lines and feeders, only those that have either overhead shield wires or solidly grounded neutrals should be counted. If the number of lines falls between the given curve values, use the curve with the lower number of lines.

To use the graphs, the approximate tower impedance of the transmission lines and feeders should be known, and the value for the grid resistance has to be calculated. Since the design has not yet been started, an approximate value can be calculated by using Equation 9-6:

Equation 9-6

$$R_g = \frac{r}{4}\sqrt{\frac{p}{A}}$$

Where:

R_g =   Substation ground resistance in Ω
r =   Soil resistivity in Ω-m (calculated in Section 9.3.2 , $r_{a(av1)}$)
A =   Area occupied by the ground grid in m^2 (calculated in Section 9.4)

Since the soil resistivity and the ground grid area are the two most important variables controlling the substation ground resistance, Equation 9-6 yields a sufficiently accurate answer to be used for the X-coordinate on the graphs. Other equations for R$_g$ are presented in IEEE Std. 80. Once the appropriate graph has been chosen with all the available information, the intersection of the substation ground resistance and the appropriate curve yields the value for the split factor on the Y-axis. Note that this value is given as a percentage and should be converted to decimal notation before using in an equation.

9.5.3   <u>The Decrement Factor, D_f</u>

The decrement factor accounts for the asymmetrical fault current wave shape during the early cycles of a fault as a result of the dc current offset. In general, the asymmetrical fault current includes the subtransient, transient, and steady-state ac components, and the dc offset current component. Both the subtransient and transient ac components and the dc offset decay exponentially, each having a different attenuation rate. However, in typical applications of this guide, it is assumed that the ac component does not decay with time but remains at its initial value.

The decrement factor can be calculated using Equation 9-7:

Equation 9-7

$$D_f = \sqrt{1 + \frac{T_a}{t_f}\left(1 - e^{\frac{-2t_f}{T_a}}\right)}$$

Where:

t_f =   Time duration of fault in seconds
T_a = $X/(\omega R)$ = the dc offset time constant in seconds

For 60 Hz,

$T_a = X/(120\pi R)$

The selection of t_f should reflect the fastest clearing time (relay plus breaker time) for transmission substations and worst-case backup clearing time for distribution and industrial substations. This conservative approach results in the highest D_f.

The X/R ratio used in the calculation of T_a is the system X/R ratio, inductive reactance to resistance, at the fault location for a given fault type. The X and R components of the system subtransient fault impedance should be used to determine the X/R ratio. The X/R ratio is the rate of decay of any dc offset. A large X/R ratio corresponds to a large time constant and a slow rate of decay.

Equation 9-7 can be used to compute the decrement factor for specific X/R ratios and fault duration. Typical values of the decrement factor for various fault durations and X/R ratios are shown in Table 9-1.

For relatively long fault durations, the effect of the dc offset current can be assumed to be more than compensated by the decay of the subtransient component of ac current. A decrement factor of 1.0 can be used for fault durations significantly greater than 1 second.

Table 9-1: Typical Values of D_f. Ref. IEEE Std. 80, Draft 13, June 19, 1998, Table 15-1. Copyright © 1998. IEEE. All rights reserved.

Fault duration, t_f		Decrement factor D_f			
Seconds	Cycles at 60 Hz	X/R = 10	X/R = 20	X/R = 30	X/R = 40
0.008 33	0.5	1.576	1.648	1.675	1.688
0.05	3	1.232	1.378	1.462	1.515
0.10	6	1.125	1.232	1.316	1.378
0.20	12	1.064	1.125	1.181	1.232
0.30	18	1.043	1.085	1.125	1.163
0.40	24	1.033	1.064	1.095	1.125
0.50	30	1.026	1.052	1.077	1.101
0.75	45	1.018	1.035	1.052	1.068
1.00	60	1.013	1.026	1.039	1.052

9.5.4 Maximum Grid Current

During a system fault, the fault current will use the earth as a partial return path to the system neutral. The current that is injected into the earth during a fault results in a ground potential rise. Typically, only a fraction of the total fault current flows from the grounding system into the earth. This is due to the transfer of current onto metallic paths such as overhead static shields, water pipelines, etc.

Faults occurring within the substation generally do not produce the worst earth currents since there are direct conductive paths that the fault current can follow to reach the system neutral (assuming the substation has a grounded-wye transformer). The faults that produce the largest ground currents are usually line-to-ground faults occurring at some distance away from the substation.

The maximum grid current is the current that flows through the grid to remote earth and is calculated by Equation 9-8.

Equation 9-8

$$I_G = D_f \cdot I_g$$

Where:
- I_G = Maximum grid current in amperes
- D_f = Decrement factor for the entire duration of fault t_f, found for t_f, given in seconds
- I_g = rms symmetrical grid current in amperes (calculated in Section 9.5.1)

9.5.5 Asymmetrical Fault

The asymmetrical fault current includes the subtransient, transient, and steady-state ac components, and the dc offset current component and can be defined as shown in Equation 9-9:

Equation 9-9

$$I_F = D_f \cdot I_f$$

Where:

    I_F =   Effective asymmetrical fault current in amperes
    I_f =   rms symmetrical ground fault current in amperes
    D_f =   Decrement factor (calculated in Section 9.5.3)

The dc offset in the fault current will cause the conductor to reach a higher temperature for the same fault conditions (fault current duration and magnitude). In addition, if present, dc offset could result in mechanical forces and absorbed energy being almost four times the value of an equivalent symmetric current case.

9.6 GROUND CONDUCTOR

9.6.1 Conductor Material

The two most commonly used materials for grounding in the United States are copper and copper-clad steel.

9.6.1.1 Copper: Copper is a common material used for grounding. Copper conductors, in addition to their high conductivity, have the advantage of being resistant to most underground corrosion because copper is cathodic with respect to most other metals that are likely to be buried in the vicinity.

9.6.1.2 Copper-Clad Steel: Copper-clad steel is usually used for underground rods and occasionally for grounding grids, especially where theft is a problem. Use of copper, or to a lesser degree copper-clad steel, ensures that the integrity of an underground network will be maintained for years, so long as the conductors are of an adequate size and not damaged and the soil conditions are not corrosive to the material used.

Other types of ground conductor materials are discussed in IEEE Std. 80.

9.6.2 Ground Conductor Sizing

The ground conductor for both the grid and equipment connections should be sized according to Equation 9-10:

Equation 9-10

$$A_{kcmil} = I \frac{197.4}{\sqrt{\left(\dfrac{TCAP}{t_c \alpha_r \rho_r}\right) \cdot \ln\left(\dfrac{K_o + T_m}{K_o + T_a}\right)}}$$

Where:

    I =   rms fault current in kA
    A_{kcmil} =   Area of conductor in kcmil
    T_m =   Maximum allowable temperature in ^{o}C
    T_a =   Ambient temperature in ^{o}C
    T_r =   Reference temperature for material constants in ^{o}C
    a_o =   Thermal coefficient of resistivity at 0^oC in $1/^o$C
    a_r =   Thermal coefficient of resistivity at reference temperature T_r in $1/^o$C
    r_r =   Resistivity of the ground conductor at reference temperature T_r in $\mu\Omega$-cm

K_o = $1/\alpha_o$ or $(1/\alpha_r) - T_r$ in °C
t_c = Fault current duration in seconds
$TCAP$ = Thermal capacity per unit volume from Table 9-2, in J/(cm$^3 \cdot$°C)

Note that $\bm{a}_r$ and $\bm{r}_r$ are both to be found at the same reference temperature of T_r degrees Celsius. Table 9-2 provides data for $\bm{a}_r$ and $\bm{r}_r$ at 20°C.

The selection of I is different for the equipment ground connection and the ground grid conductors and is discussed in Sections 9.6.3 and 9.6.4.

Table 9-2: Material Constants Data for Equation 9-10. Ref. IEEE Std. 80,
Table 11-1. Copyright © 1998. IEEE. All rights reserved.

Description	Material Conductivity (%)	α_r Factor @ 20°C (1/°C)	K_o @ 0°C (°C)	Fusing[a] Temperature T_m (°C)	ρ_r @ 20°C (μΩ-cm)	TCAP Thermal Capacity [J/(cm$^3 \cdot$°C)]
Copper, annealed soft-drawn	100.0	0.003 93	234	1083	1.72	3.42
Copper, commercial hard-drawn	97.0	0.003 81	242	1084	1.78	3.42
Copper-clad steel wire	40.0	0.003 78	245	1084	4.40	3.85
Copper-clad steel wire	30.0	0.003 78	245	1084	5.86	3.85
Copper-clad steel rod[b]	20.0	0.003 78	245	1084	8.62	3.85

[a] From ASTM standards.
[b] Copper-clad steel rod based on 0.010 in. (0.254 mm) copper thickness.

9.6.2.1 Formula Simplification: The formula in English units can be simplified to Equation 9-11:

Equation 9-11

$$A_{kcmil} = I \cdot K_f \sqrt{t_c}$$

Where:
A_{kcmil} = Area of conductor in kcmil
I = rms fault current in kA
t_c = Fault current duration in seconds
K_f = Constant from Table 9-3 for the material at various values of T_m (fusing temperature or limited conductor temperature) and using ambient temperature (T_a) of 40 °C

9.6.3 Sizing Equipment Ground Conductor

In determining the size of the equipment ground conductors, use the total fault current since it has to flow through the equipment ground conductors before it can reach the ground grid and divide among various conductive and earth paths to reach the system neutral. Use the effective asymmetrical fault current, I_F, for I in Equation 9-10 when sizing the equipment ground conductors.

Table 9-3: Material Constants Data for Equation 9-11. Ref. IEEE Std. 80,
Table 11-2. Copyright © 1998. IEEE. All rights reserved.

Material	Conductivity (%)	T_m [a] (^{o}C)	K_f
Copper, annealed soft-drawn	100.0	1083	7.00
Copper, commercial hard-drawn	97.0	1084	7.06
Copper, commercial hard-drawn	97.0	250	11.78
Copper-clad steel wire	40.0	1084	10.45
Copper-clad steel wire	30.0	1084	12.06
Copper-clad steel rod	20.0	1084	14.64

[a] See Section 9.6.5 for comments concerning material selection.

9.6.4 Sizing Ground Grid Conductors

IEEE Std. 80 suggests using I_G for I in Equation 9-10 in the design of the grid to take advantage of the fact that not all the fault current flows through the earth and prevent overdesigning the grounding system. The current I_G should, however, reflect the worst fault type and location, the decrement factor, and any future system expansion. Another more conservative approach is to use I_F (Section 9.5.5) for I in Equation 9-10.

The use of I_F will result in a larger conductor that will provide extra strength for installation, take into account the effects of corrosion, and provide some margin for unexpected future system expansion. It is best to be conservative and provide an adequate margin when sizing the ground grid conductors as a result of the expense involved in replacing or upgrading existing ground conductors at a later date.

9.6.5 Additional Conductor Sizing Factors

The designer should take precautions to ensure that the temperature of any conductor and connection in the grounding installation does not pose a danger to the safe operation of the substation. For instance:

   a. Typically, conductors and connections near flammable materials should be subject to more stringent temperature limitations.
   b. If the strength of hard-drawn copper is required for mechanical reasons, then it may be prudent not to exceed 250^oC to prevent annealing of the conductors.

Carefully examine the possible exposure to a corrosive environment. Even when the correct conductor size and the selected joining (connecting) method have satisfied all the test requirements of IEEE Std. 837, "Qualifying Permanent Connections Used in Substation Grounding," it may be prudent to choose a larger conductor size to compensate for some gradual reduction in the conductor cross section during the design life of the installation where the soil environment tends to promote corrosion.

9.6.6 Connections from Equipment and Structures to Ground Grid

Pay careful attention to the connections of substation structures, equipment frames, and neutrals to the ground grid to realize the benefits of an effective ground grid system. Conductors of adequate ampacity and mechanical strength should be used for the connections between:

   1. All ground electrodes, such as grounding grids, rodbeds, ground wells, and, where applicable, metal, water, or gas pipes, water well casings, etc.

2.   All above-ground conductive metal parts that might accidentally become energized, such as metal structures, machine frames, metal housings of conventional or gas-insulated switchgear, transformer tanks, guards, etc. Also, conductive metal parts that might be at a different potential relative to other metal parts that have become energized should be bonded together, usually via the ground grid.

3.   All fault current sources such as surge arresters, capacitor banks or coupling capacitors, transformers, and, where appropriate, machine neutrals, lighting, and power circuits.

Solid bare copper ground conductor or wire is usually employed for these ground connections. However, transformer tanks are sometimes used as part of a ground path for surge arresters on them. Similarly, most steel or aluminum structures may be used for the ground path if it can be established that their conductance, including that of any connections, is and can be maintained as equivalent to that of the conductor that would normally be installed. Where this practice is followed, any paint films that might otherwise introduce a highly resistive connection should be removed and a suitable joint compound applied or other effective means, such as jumpers across the connections, taken to prevent subsequent deterioration of the connection. Do not assume equal division of currents between multiple ground leads at cross-connections or similar junction points.

Extra ground connections should be considered at all critical locations (such as at equipment neutrals, surge arrester grounds, operating handles and ground mats, etc.) to ensure an effective grounding capability even when one conductor is broken or a connection is improperly made. Do not assume equal division of currents between multiple ground connections.

Securely attach the shortest possible length ground conductor to structures and/or equipment and form the conductor to conform to the foundation with minimum exposure to mechanical damage. Conductor sizes for any critical connection should not be smaller than 1/0 AWG to ensure mechanical adequacy.

Periodically inspect all accessible ground leads. Exothermic weld, brazed, or compression-type connectors can be used for underground connections. However, exothermic welds are widely used and recommended by RUS for underground connections. Compression connectors if used in grounding applications should be of a type that compresses the conductor and the connector into a tight homogenous mass, removing virtually all air. Use an oxide-inhibiting compound with all compression connectors to seal out air and moisture and prevent oxidation or corrosion in the connection.

> Oxidation or corrosion in the connection can create hot spots that can shorten the life of the connection. With the connection below grade, there is no visual way of knowing when the connection has failed. A properly installed exothermic connection is a molecular connection that eliminates the oxidation and corrosion in the connection and reduces the opportunity for hot spots.

The connector chosen should satisfy the requirements of IEEE Std. 837. Avoid soldered connections because of the possibility of failure under high fault currents.

9.7 SAFETY CONSIDERATIONS

Under ground fault conditions, the portion of fault current flowing between a substation ground grid and the surrounding earth, I_G, will result in potential gradients within and around the substation. Unless proper precautions are taken in design, the maximum gradients present can result in a potential hazard to a

person in or near the substation. In addition to the voltage magnitude of the local gradients, such things as duration of the current flow, impedances in its path, body resistance, physical condition of the person, and probability of contact all enter into the safety considerations.

9.7.1 Tolerable Limits of Body Current

The most common physiological effects of electric current on the body, stated in order of increasing current magnitude, are perception, muscular contraction, unconsciousness, fibrillation of the heart, respiratory nerve blockage, and burning.

The threshold of perception for the human body is about one milliampere at commercial (50 or 60 Hz) frequencies. Currents of 1 to 6 mA, often termed let-go currents, though unpleasant to sustain, generally do not impair the ability of a person holding an energized object to control his muscles and release it. Higher currents (about 9 to 25 mA) can result in painful situations and affect the muscles so that the energized object is difficult if not impossible to release. Still higher mA currents can affect breathing and may cause fatalities if duration (usually on the order of minutes) is long enough. Further current increases (about 60 mA and above) can result in ventricular fibrillation of the heart. Sixty mA is approximately the current drawn by a 7.5 watt 120 V lamp. Currents above the level for ventricular fibrillation can cause heart paralysis, inhibition of breathing, and burns.

Since currents of a magnitude that exceed let-go level can affect breathing, they have to be avoided if the duration is likely to be long. Fortunately, in most situations in substations, the protective relays will prevent any fault from lasting that long. Therefore, it is usually those levels of current that can lead to ventricular fibrillation that form the basis for most potential gradient limitation efforts.

It is assumed that 99.5 percent of all persons can safely withstand, without ventricular fibrillation, the passage of a current with magnitude and duration determined by Equation 9-12:

> Equation 9-12

$$I_B = \frac{k}{\sqrt{t_s}}$$

Where:
I_B = rms magnitude of the current through the body in amperes
t_s = Duration of the current exposure in seconds
k = Constant related to electric shock energy

For a person weighing 50 kg (110 lbs), $k = 0.116$
For a person weighing 70 kg (155 lbs), $k = 0.157$

Equation 9-12 is based on tests limited to a range of between 0.03 and 3.0 s, and is not valid for very short or long durations.

Equation 9-12 indicates that much higher body currents can be allowed where fast operating protective devices can be relied upon to limit the fault duration. An engineering decision based on judgment is needed as to whether to use the clearing time of primary high-speed relays, or that of the backup protection, as the basis for calculation.

9.7.2 Typical Shock Situations

Figures 9-28 (see page 541 of this bulletin) and 9-29 (see page 542 of this bulletin) show five basic situations involving a person and grounded facilities during a fault. In these figures E_s is the step voltage, E_t is the touch voltage, E_m is the mesh voltage, and E_{trrd} is the transferred voltage.

During a fault, the earth conducts currents emanating from the grid and other permanent ground electrodes buried below the earth surface.

In the case of conventional substations, the typical case of metal-to-metal touch voltage occurs when metallic objects or structures within the substation site are not bonded to the ground grid. Objects such as pipes, rails, or fences not bonded to the ground grid that are located within or near the substation ground grid area meet these criteria. Substantial metal-to-metal touch voltages may be present when a person standing on or touching a grounded object or structure comes into contact with a metallic object or structure within the substation site that is not bonded to the ground grid. Calculation of the actual metal-to-metal touch voltage is complex. In practice, hazards resulting from metal-to-metal contact may best be avoided by bonding potential danger points to the substation grid.

9.8 TOLERABLE TOUCH AND STEP VOLTAGES

The tolerable touch and step voltages are the criteria that have to be met to ensure a safe design. The lower the maximum touch and step voltages, the more difficult it is to produce an adequate grid design. In most cases the tolerable touch voltage will be the limiting factor. Figures 9-30 through 9-34 are used to derive the equations for maximum touch and step voltages.
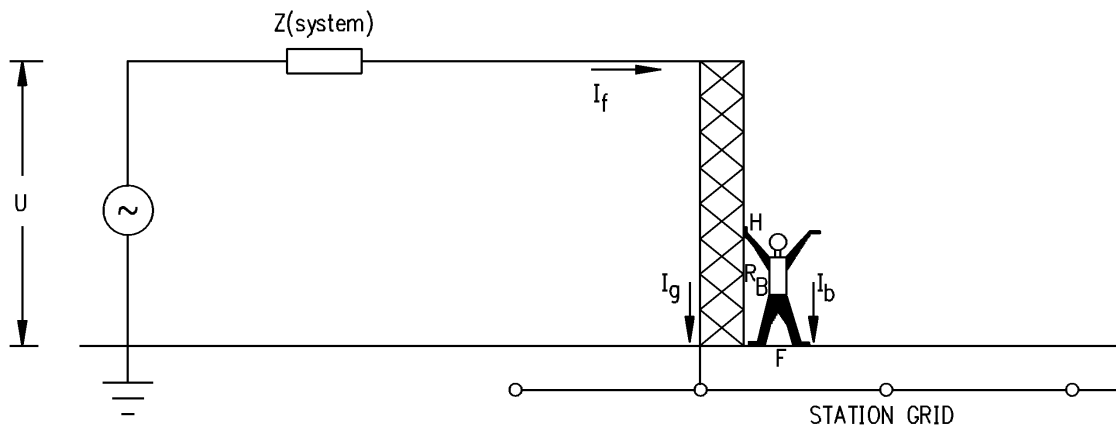
Figure 9-30: Exposure to Touch Voltage. Ref. IEEE Std. 80, Draft 13, June 19, 1998, Figure 7-1. Copyright © 1998. IEEE. All rights reserved.
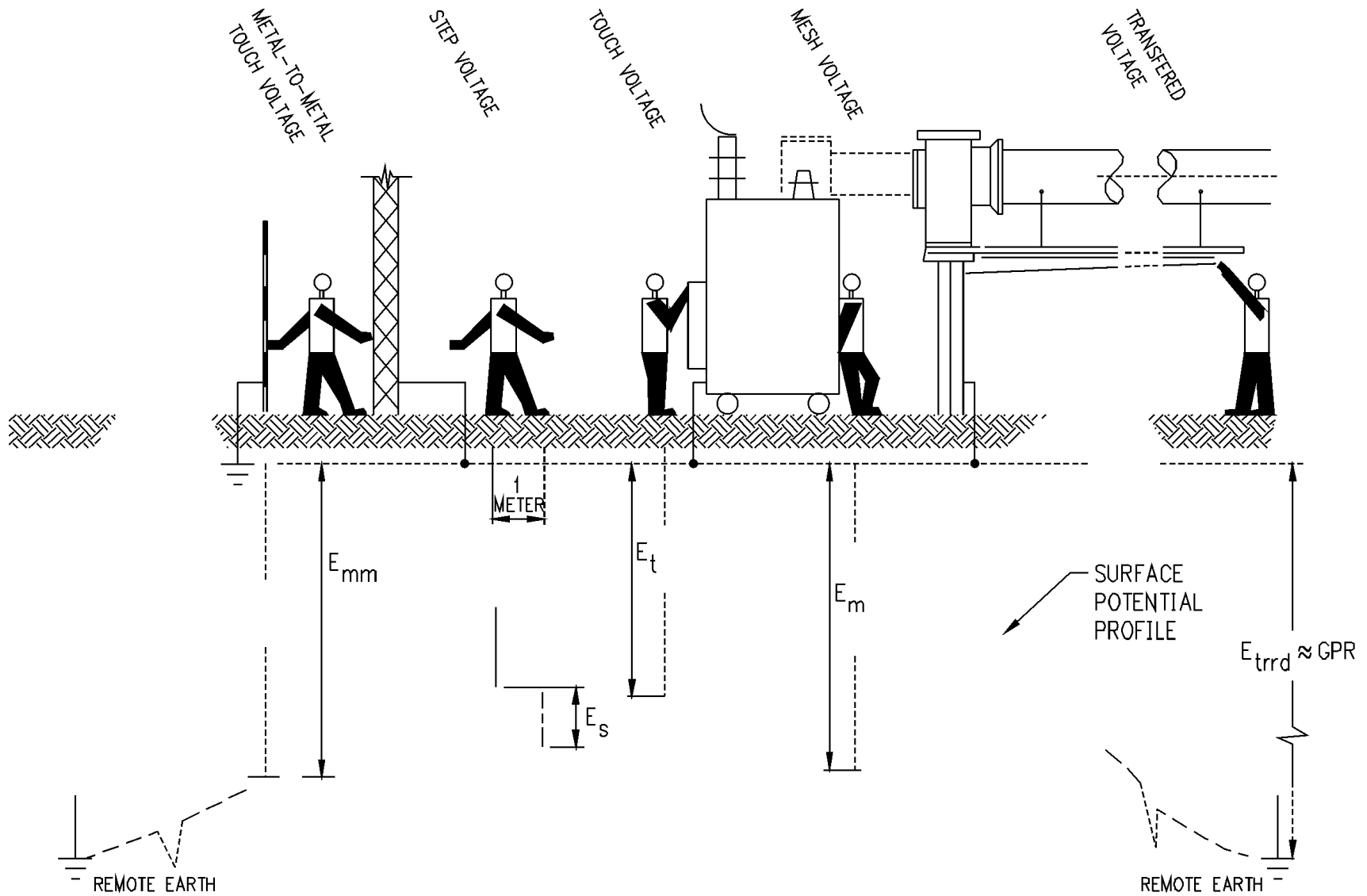
Figure 9-28: Basic Shock Situations. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 8-1. Copyright © 1998. IEEE. All rights reserved.
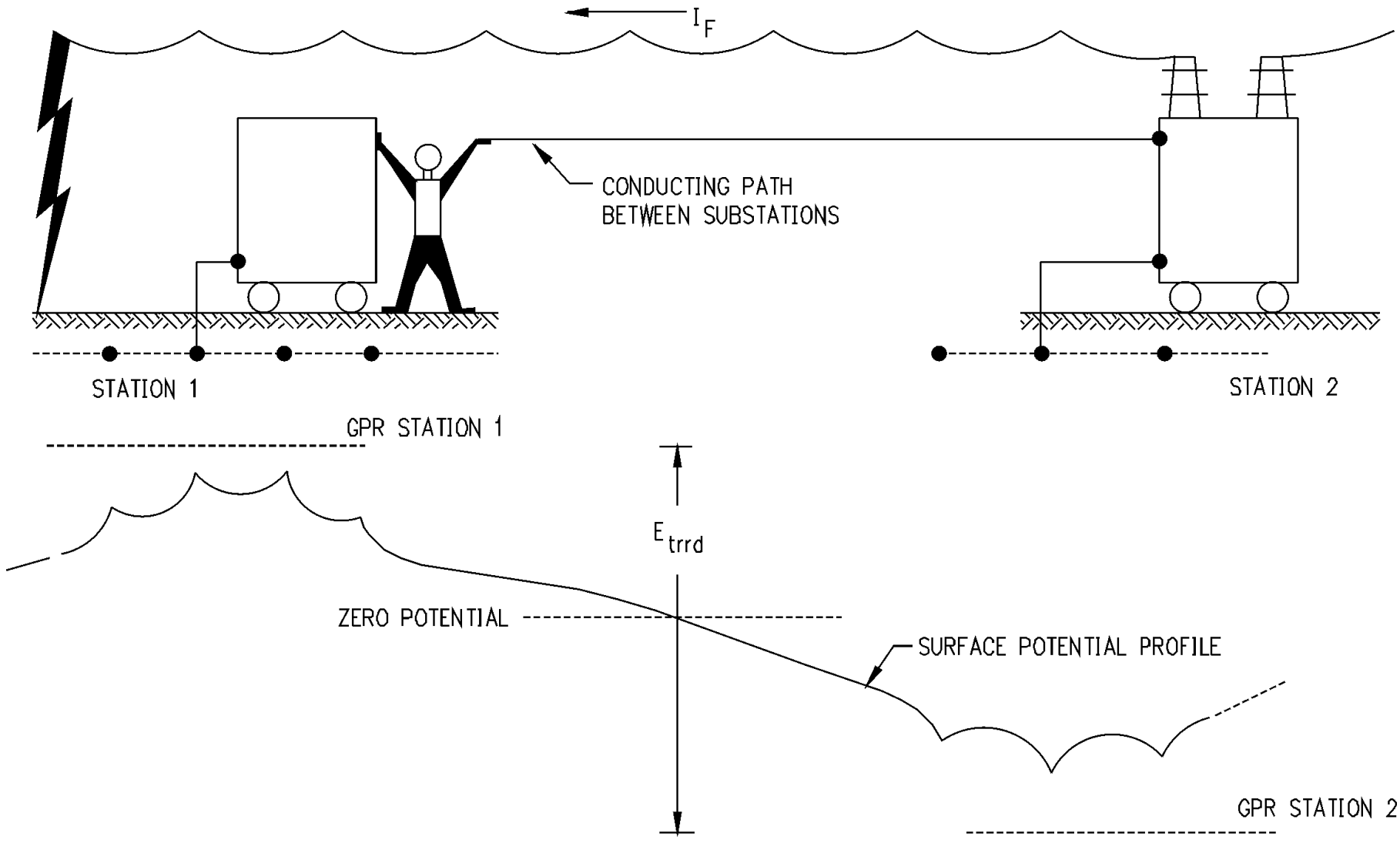
Figure 9-29: Typical Situation of External Transferred Potential. Ref. IEEE Std. 80, Draft 13, June 19, 1998, Figure 8-2. Copyright © 1998. IEEE. All rights reserved.
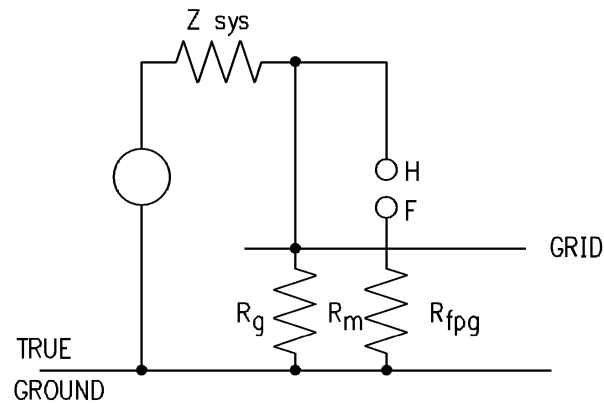
Figure 9-31: Impedances in Touch Voltage Circuit.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 7-2. Copyright © 1998. IEEE. All rights reserved.
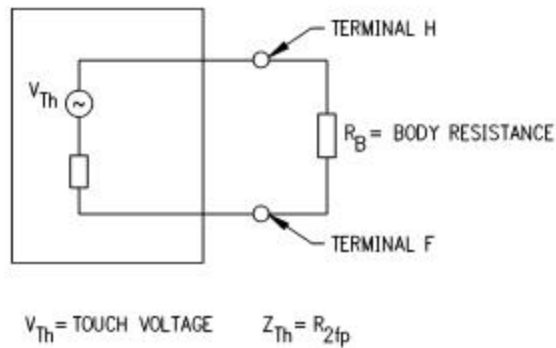
Figure 9-32: Touch Voltage Circuit.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 7-3. Copyright © 1998. IEEE. All rights reserved.
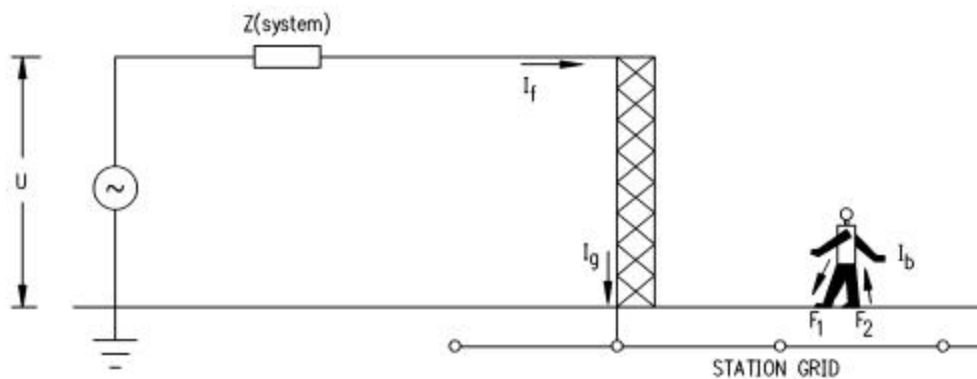
Figure 9-33: Exposure to Step Voltage.
Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 7-4. Copyright © 1998. IEEE. All rights reserved.

V_{Th}= STEP VOLTAGE Z_{Th}= R_{2fs}
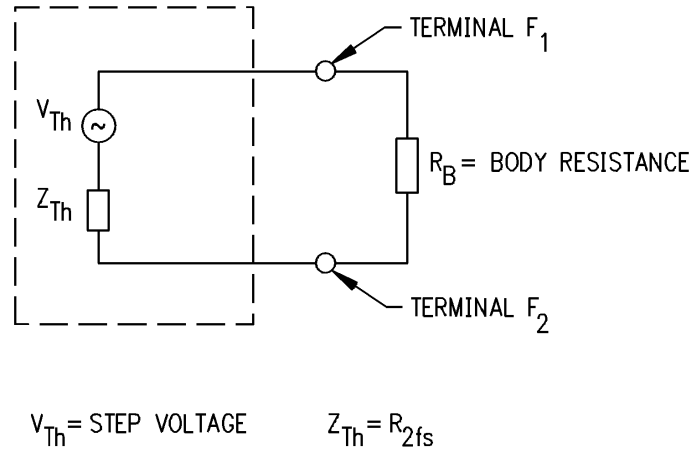
Figure 9-34: Step Voltage Circuit. Ref. IEEE Std. 80, Draft 13, June 19, 1998,
Figure 7-5. Copyright © 1998. IEEE. All rights reserved.

The equations for the maximum touch and step voltages are as follows:

Equation 9-13

$$E_{step} = \left(R_B + 2R_f\right) \cdot I_B$$

Equation 9-14

$$E_{touch} = \left(R_B + \frac{R_f}{2}\right) \cdot I_B$$

Where:

E_{step}	=	Step voltage in volts
E_{touch}	=	Touch voltage in volts
R_B	=	Resistance of the human body to electric current. R_B is generally estimated to be 1000 Ω for dc and 50 or 60 Hz ac current.
R_f	=	Ground resistance of one foot:

Equation 9-15
$R_f = C_s 3\rho_s$

C_s is the surface layer derating factor based on the thickness of the protective surface layer spread above the earth grade at a substation. If no protective surface layer is used, then $C_s = 1$ and is defined further in Section 9.9.1.

ρ_s is the resistivity of the protective surface layer used at the substation in Ω-m. If no protective surface layer is used, then $\rho_s = \rho$ = resistivity of homogenous earth as calculated in Section 9.3.2.

I_B is defined in Section 9.7.1.

Substituting for I_B, R_B, R_f, and k in Equations 9-13, 9-14, and 9-15:

For body weight of 50 kg (110 lbs):

Equation 9-16

$$E_{step50} = \left(1000 + 6C_s \cdot \boldsymbol{r}_s\right)\frac{0.116}{\sqrt{t_s}}$$

Equation 9-17

$$E_{touch50} = \left(1000 + 1.5C_s \cdot \boldsymbol{r}_s\right)\frac{0.116}{\sqrt{t_s}}$$

For body weight of 70 kg (155 lbs):

Equation 9-18

$$E_{step70} = \left(1000 + 6C_s \cdot \boldsymbol{r}_s\right)\frac{0.157}{\sqrt{t_s}}$$

Equation 9-19

$$E_{touch70} = \left(1000 + 1.5C_s \cdot \boldsymbol{r}_s\right)\frac{0.157}{\sqrt{t_s}}$$

Determine t_s. The faster the clearing time of the fault, the less risk there is to personnel. Both tests and experience show that the chance of severe injury or death is greatly reduced if the duration of a current flow through the body is very brief. Given all of the above safety factors and using the assumption that not all of the worst-case conditions will be present at the time of the fault, the worst-case **primary** clearing time for the substation can be used. An extremely conservative design would use the backup clearing time because it ensures a greater safety margin.

9.9 PROTECTIVE SURFACE MATERIAL AND REDUCTION FACTOR C_S

A thin layer of highly resistive protective surface material such as gravel spread above the earth grade at a substation can greatly reduce the available shock current at a substation. The surface material increases the contact resistance between the soil and the feet of people in the substation. The surface material is generally 0.08 to 0.15 meter (3 to 6 inches) in depth and extends 0.91 to 1.22 meters (3 to 4 feet) outside the substation fence. If the surface material does not extend outside the substation fence, then the touch voltage may become dangerously high.

A test at a substation in France showed that the river gravel used as surface material when moistened had a resistivity of 5000 Ω-m. A layer 0.1 to 0.15 meter (4 to 6 inches) thick decreased the ratio of body to short-circuit current by a ratio of 10:1, as compared to the natural moist ground.

The range of resistivity values for the surface material layer depends on many factors, some of which are kinds of stone, size, condition of stone (that is, clean or with fines), amount and type of moisture content, atmospheric contamination, etc. Table 9-4 indicates that the resistivity of the water with which the rock is wet has considerable influence on the measured resistivity of the surface material layer. Thus, surface material subjected to sea spray may have substantially lower resistivity than surface material utilized in arid environments.

Table 9-4 gives typical resistivity values for different types of surface material measured by several different parties in different regions of the United States. These values are not valid for all types and sizes of stone in any given region. Perform tests to determine the resistivity of the stone typically used in the region's substations.

Table 9-4: Typical Surface Material Resistivities. Ref. IEEE Std. 80,
Table 12-1. Copyright © 1998. IEEE. All rights reserved.

No.	Description of Surface Material	Resistivity of Sample, Ω-m	
		Dry	Wet
1	Crusher Run Granite with Fines (NC)	140×10^6	1300 (Groundwater, 45 Ω-m)
2	1½ in. (0.04 m) Crusher Run Granite (GA) with Fines	4000	1200 (Rainwater, 100 Ω-m)
3	¾-1 in. (0.02-0.025 m) Granite (CA) with Fines	—	6513 (10 Minutes After 45 Ω-m Water Drained)
4	#4 (1 -2 in.) (0.025-0.05 m) Washed Granite (GA)	1.5×10^6 to 4.5×10^6	5000 (Rainwater, 100 Ω-m)
5	#3 (2-4 in.) (0.05-0.1 m) Washed Granite (GA)	2.6×10^6 to 3×10^6	10 000 (Rainwater, 100 Ω-m)
6	Size Unknown, Washed Limestone (MI)	7×10^6	2000 - 3000 (Groundwater, 45 Ω-m)
7	Washed Granite, Similar to ¾-in. (0.02 m) Gravel	2×10^6	10 000
8	Washed Granite, Similar to Pea Gravel	40×10^6	5000
9	#57 (¾-in.) (0.02 m) Washed Granite (NC)	190×10^6	8000 (Groundwater, 45 Ω-m)
10	Asphalt	2×10^6 to 30×10^6	10 000 to 6×10^6
11	Concrete	1×10^6 to 1×10^9 [a]	21 to 100

[a] Oven-dried concrete. Values for air-cured concrete can be much lower due to moisture content.

9.9.1 Reduction Factor C_s

An analytical expression for the ground resistance of the foot on a thin layer of surface material can be obtained from Equation 9-20:

Equation 9-20

$$C_s = 1 + \frac{16 \cdot b}{\rho_s} \sum_{n=1}^{\infty} K^n R_{m(2nh_s)}$$

Equation 9-21

$$K = \frac{r - r_s}{r + r_s}$$

Where:

C_s	=	Surface layer derating factor
K	=	Reflection factor between different material resistivities
r_S	=	Surface material resistivity in ohm-meters

r = Resistivity of the earth beneath the surface material in ohm-meters
h_s = Thickness of the surface material in meters
b = Radius of the circular metallic disc representing the foot in meters
$R_{m(2nh_s)}$= Mutual ground resistance between the two similar, parallel, coaxial plates, separated by a distance ($2nh_s$), in an infinite medium of resistivity r_s in ohm-meters

Because the quantity C_s is rather tedious to evaluate without the use of a computer, these values have been precalculated for b = 0.08 m and are given in the form of graphs in Figure 9-35.
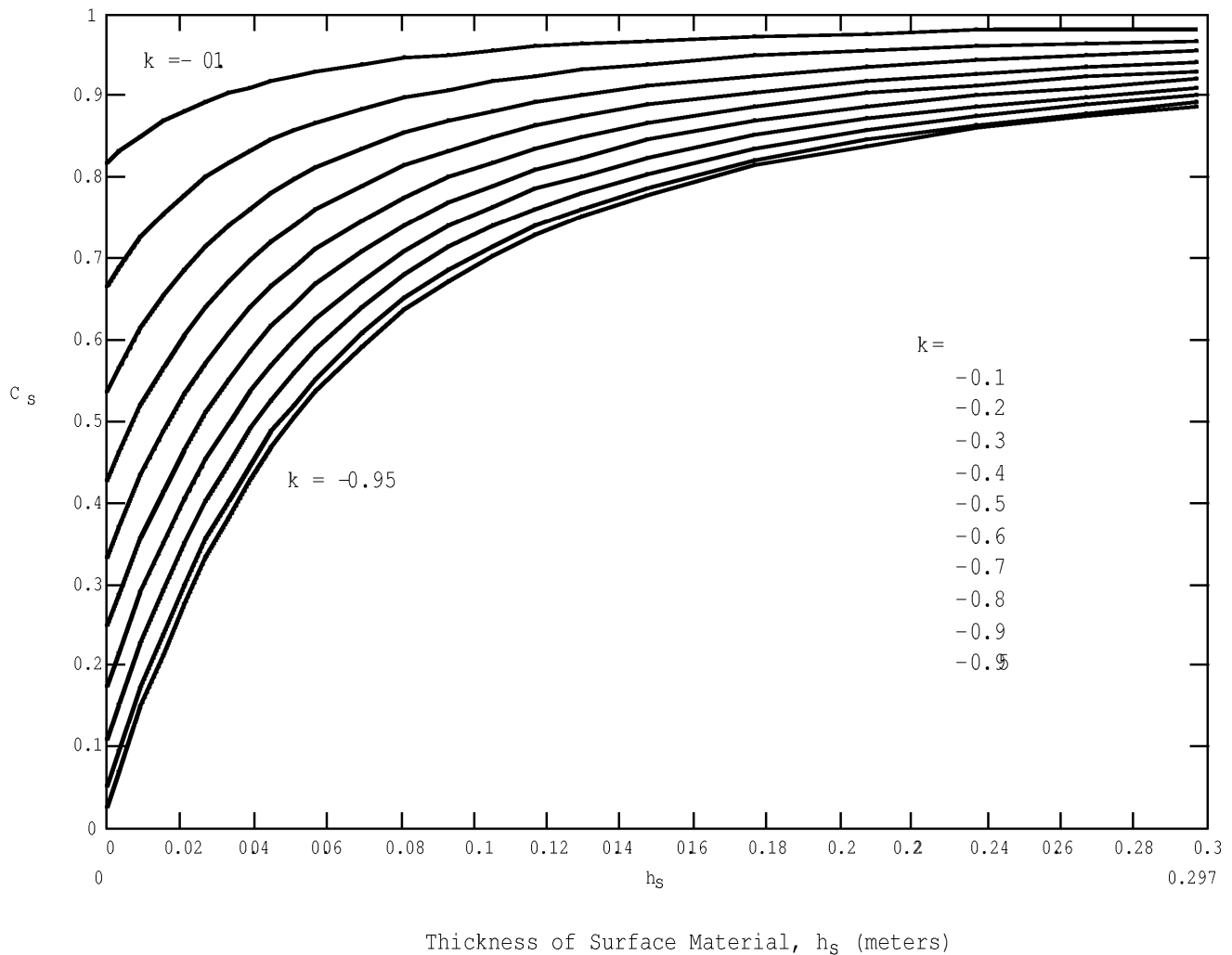
Figure 9-35: C_s versus h_s. Ref. IEEE Std. 80, Draft 13, June 19, 1998, Figure 7-6. Copyright © 1998. IEEE. All rights reserved.

The value for C_s can be read off the Y-axis of Figure 9-35 by finding the intersection of the appropriate curve for K with the thickness of the surface layer of rock. For the initial design, this value should be set to 0.101 meter (4 inches) unless a standard thickness is typically used.

9.10   DESIGN OF A SUBSTATION GROUNDING SYSTEM

9.10.1   General Concepts

The prevailing practice for a grounding system of most utilities both in the United States and other countries is the use of buried horizontal conductors in the form of a grid, supplemented by a number of vertical ground rods connected to this grid. Some of the reasons behind the system of vertical rods and horizontal conductors are that horizontal (grid) conductors are most effective in reducing the danger of high step and touch voltages on the earth surface. Vertical ground rods penetrating the lower resistivity soil are far more effective in dissipating fault currents whenever a two- or multi-layer soil is encountered and the upper soil layer has a higher resistivity than the lower soil layer. This is important because the resistivity of lower soil layers remains nearly constant with changing seasons while the upper soil layer resistivity may experience high resistivity conditions with seasonal changes due to the freezing or drying of the upper soil layer.

Several parameters define the geometry of the grid, but the area of the grounding system, the conductor spacing, and the depth of the ground grid have the most impact on the mesh voltage, while parameters such as the conductor diameter and the thickness of the surfacing material have less impact. The area of the grounding system is the single most important geometrical factor in determining the resistance of the grid. The larger the area grounded, the lower the grid resistance and, thus, the lower the GPR.

9.10.2   Design Procedures

1.   The grounding system grid shall consist of a network of bare conductors buried in the earth to provide for grounding connections to grounded neutrals, equipment ground terminals, equipment housings, and structures and to limit the maximum possible shock current during ground fault conditions to safe values. If the calculated mesh and step voltages of the grid design are below the maximum values for touch and step voltage, then the design is considered adequate. Personnel may still receive a shock during fault conditions, but that shock will not be sufficient to cause ventricular fibrillation.

2.   The ground grid should encompass all of the area within the substation fence and extend at least 0.91 meter (3.0 feet) outside the substation fence. A perimeter grid conductor should be placed 0.91 meter (3.0 feet) outside and around the entire substation fence including the gates in any position. A perimeter grid conductor should also surround the substation equipment and structure cluster in cases where the fence is located far from the cluster.

3.   A soil resistivity test, such as described in Section 9.3, will determine the soil resistivity profile and the soil model needed (that is, uniform or two-layer model). Estimates of the preliminary resistance of the grounding system in uniform soil can be determined using Equation 9-3. For the final design, more accurate estimates of the resistance may be desired. Computer analysis based on modeling the components of the grounding system in detail can compute the resistance with a high degree of accuracy, assuming the soil model is chosen correctly.

4.   The fault current $3I_0$ should be the maximum expected future fault current that will be conducted by any conductor in the grounding system, and the time t_c should reflect the maximum possible clearing time (including backup).

5. The tolerable touch and step voltages are determined by equations given in Section 9.8. The choice of time t_s is based on the judgment of the design engineer, with guidance from IEEE Std. 80 (clauses 5.2 to 6.3). Using the assumption that not all the worst-case conditions will be present at the time of the fault, the worst-case primary clearing time for the substation can be used for t_s. An extremely conservative design would use the backup clearing time for t_s.

6. The equipment ground conductor size is determined according to Section 9.6.2.

7. The entire area inside the fence and including a minimum of 1.0 meter (3.3 feet) outside the fence needs to be covered with a minimum layer of 10 cm (4 inches) of protective surface material such as crushed rock (or approved equal) possessing a minimum resistivity of 3,000 ohm-meters wet or dry.

8. The ground grid consists of horizontal (grid) conductors placed in the ground to produce square mesh. This can be visualized as a checkerboard pattern. One row of horizontal conductors is equally spaced 3 to 15 meters (9.8 to 49.2 feet) apart. A second row of equally spaced horizontal conductors running perpendicular to the first row is spaced at a ratio of 1:1 to 1:3 of the first row's spacing. For example, if the first row spacing was 3 meters (9.8 feet), the second row spacing could be between 3 to 9 meters (9.8 to 29.5 feet). The crossover point for the first and second row of conductors should be securely bonded together. The purpose of the bonded connections is to ensure adequate control of surface potential, secure multiple paths for fault currents, minimize the voltage dorp in the grid, and provide a certain measure of redundancy in case of conductor failure. Grid conductors range in size from 2/0 AWG (67 mm^2) to 500 kcmil (253 mm^2); the conductor diameter has negligible effect on the mesh voltage. The actual grid conductor size is calculated in accordance with Section 9.6.4.

9. Grid conductors should be buried a minimum of 0.46 meter (18 inches) to 1.5 meters (59.1 inches) below final earth grade (excluding crushed rock covering) and may be plowed in or placed in trenches. In soils that are normally quite dry near the surface, deeper burial may be required to obtain desired values of grid resistance.

10. Vertical ground rods may be at the grid corners and at junction points along the perimeter. Ground rods may also be installed at major equipment, especially near surge arresters. In multi-layer or high-resistivity soils, it might be useful to use longer rods or rods installed at additional junction points. Vertical ground rods should be 1.6 cm (5/8 inch) diameter by at least 2.5-meter (8.0-foot) long copper, steel, or other approved type from the List of Materials, RUS IP 202-1. Where used, they should be installed with tops 5 cm (1.97 inches) minimum below grade and bonded to the ground grid connectors. A good design practice is to space rods not closer than their length. An additional determinant is having enough rods so that their average fault current pickup would not exceed 300 amperes, assuming all ground system current entering the grid through the rods.

11. If the GPR calculated according to Section 9.10.6 of the preliminary design is below the tolerable touch voltage, no further analysis is necessary. The design needs only the refinements required to provide access to equipment grounds.

12. The calculation of the mesh and step voltages for the grid as designed can be done using the approximate analysis techniques described in Sections 9.10.4 and 9.10.5 for uniform soil.

13. If the computed mesh voltage is below the tolerable touch voltage, the design may be complete. If the computed mesh voltage is greater than the tolerable touch voltage, the preliminary design should be revised (see Section 9.10.7).

14. Both the computed touch and step voltages have to be below the tolerable voltages. If not, the preliminary design has to be revised (see Section 9.10.7).

15. If either the step or touch tolerable limits are exceeded, revision of the grid design is required. These revisions may include smaller conductor spacing, additional ground rods, etc. More discussion on the revision of the grid design to satisfy the step and touch voltage limits is given in Section 9.10.7.

16. After satisfying the step and touch voltage requirements, additional grid and ground rods may be required. The additional grid conductors may be required if the site is irregular or if the grid design does not include conductors near equipment to be grounded. Additional ground rods may be required at the base of surge arresters, transformer neutrals, etc. Also review the final design to eliminate hazards due to transferred potential (Section 9.10.11) and hazards associated with special areas of concern (Section 9.10.10).

9.10.3 Preliminary Design

The design criteria are the tolerable touch and step voltages. For a preliminary design, the grid will consist of uniform square or rectangular mesh. This is so the touch and step voltages calculated by the simplified design equations of IEEE Std. 80 are valid for every location within the ground grid. Once a safe preliminary design has been achieved, then the ground grid may be modified so that the grid does not consist entirely of uniform square or rectangular mesh. These modifications are described in Section 9.10.2, Step 16. Make sure that all grid modifications do not result in mesh that is larger than the one used in the preliminary design since it could result in unsafe touch and step voltages. Remember that additional ground conductors added to the preliminary design will result in a more conservative design, and fewer ground conductors than the preliminary design could result in an unsafe design.

Take the following steps to arrive at a preliminary design:

1. On a layout drawing of the substation site, draw in the largest square, rectangular, triangular, T-shaped, or L-shaped grids that will fit within the site; this should already have been done to calculate the grid area in Section 9.4.

2. Place grid conductors to produce square mesh of approximately 6.1 to 12.2 meters (20 to 40 feet) on a side.

3. Set the grid depth, h, equal to 45.72 cm (18 inches).

4. Set the thickness of surface material equal to 10.16 cm (4 inches).

5. Place ground rods around the perimeter of the substation. As a general rule, place a ground rod at every other perimeter grid connection and at the corners of the substation. Since ground rods discharge most of their current through their lower portion, they are effective in controlling the large current densities (and associated large step and touch potentials) that are present in the perimeter conductors during fault conditions.

9.10.4   Calculate Design Mesh Voltage

Mesh voltage (a form of touch voltage) is taken as being from a grounded structure to the center of a rectangle of the substation grounding grid mesh. Mesh voltages represent the highest possible touch voltages that may be encountered within a substation's grounding system and thus represent a practical basis for designing a safe grounding system for within, and immediately outside, the substation fence area. The mesh voltage has to be less than the tolerable touch voltage for the grounding system to be safe.

However, the mesh voltage may not be the worst-case touch voltage if ground rods are located near the perimeter, or if the mesh spacing near the perimeter is small. In these cases, the touch voltage at the corner of the grid may exceed the corner mesh voltage.

In a substation that utilizes a grid as part of the grounding system, it is theoretically possible to design and install the grid in such a way that the mesh voltage can be kept within desired limits.

The mesh voltage values are obtained as a product of the geometrical factor K_m, a corrective factor K_i that accounts for some of the error introduced by the assumptions made in deriving K_m, the soil resistivity (r), and the average current per unit of effective buried length of the grounding system conductor (I_G/L_M):

Equation 9-22

$$E_m = \frac{r \cdot K_m \cdot K_i \cdot I_G}{L_M}$$

Where:

ρ	=	Soil resistivity, Ω-m
K_m	=	Spacing factor for mesh voltage, simplified method
K_i	=	Correction factor for grid geometry, simplified method
I_G	=	Maximum grid current that flows between ground grid and surrounding earth (including dc offset) in amperes
L_M	=	Effective length of $L_C + L_R$ for mesh voltage in meters
L_C	=	Total length of grid conductor in meters
L_R	=	Total length of ground rods in meters

The geometrical factor K_m is expressed by Equation 9-23:

Equation 9-23

$$K_m = \frac{1}{2 \cdot p} \cdot \left[\ln \left[\frac{D^2}{16 \cdot h \cdot d} + \frac{(D + 2 \cdot h)^2}{8 \cdot D \cdot d} - \frac{h}{4 \cdot d} \right] + \frac{K_{ii}}{K_h} \cdot \ln \left[\frac{8}{p(2 \cdot n - 1)} \right] \right]$$

Where:

D	=	Spacing between parallel conductors in meters
d	=	Diameter of grid conductors in meters
h	=	Depth of ground grid conductors in meters
n	=	Geometric factor composed of factors n_a, n_b, n_c, and n_d
K_h	=	Corrective weighting factor that emphasizes the effects of grid depth, simplified method
K_{ii}	=	Corrective weighting factor that adjusts for the effects of inner conductors on the corner mesh, simplified method

For grids with ground rods along the perimeter, or for grids with ground rods in the grid corners as well as both along the perimeter and throughout the grid area,

$$K_{ii} = 1$$

For grids with no ground rods or grids with only a few ground rods, none located in the corners or on the perimeter:

Equation 9-24

$$K_{ii} = \frac{1}{(2 \cdot n)^{\frac{2}{n}}}$$

Equation 9-25

$$K_h = \sqrt{1 + \frac{h}{h_o}} \qquad h_o = 1 \text{ m (grid reference depth)}$$

The effective number of parallel conductors in a given grid, n, can be made applicable both to rectangular or irregularly shaped grids that represent the number of parallel conductors of an equivalent rectangular grid:

Equation 9-26

$$n = n_a \cdot n_b \cdot n_c \cdot n_d$$

Where:

Equation 9-27

$$n_a = \frac{2 \cdot L_C}{L_p}$$

$n_b = 1$ for square grids
$n_c = 1$ for square and rectangular grids
$n_d = 1$ for square, rectangular, and L-shaped grids

Otherwise:

Equation 9-28

$$n_b = \sqrt{\frac{L_p}{4 \cdot \sqrt{A}}}$$

Equation 9-29

$$n_c = \left[\frac{L_x \cdot L_y}{A} \right]^{\frac{0.7 \cdot A}{L_x \cdot L_y}}$$

Equation 9-30

$$n_d = \frac{D_m}{\sqrt{L_x^2 + L_y^2}}$$

L_C = Total length of the conductor in the horizontal grid in meters
L_p = Peripheral length of the grid in meters
A = Area of the grid in m^2
L_x = Maximum length of the grid in the x direction in meters
L_y = Maximum length of the grid in the y direction in meters
D_m = Maximum distance between any two points on the grid in meters
D = Spacing between parallel conductors in meters
d = Diameter of grid conductors in meters
h = Depth of ground grid conductors in meters

The irregularity factor, K_i, used in conjunction with the above-defined n is expressed by Equation 9-31:

Equation 9-31
$$K_i = 0.644 + 0.148 \cdot n$$

For grids with no ground rods, or grids with only a few ground rods scattered throughout the grid but none located in the corners or along the perimeter of the grid, the effective buried length, L_M, is expressed by Equation 9-32:

Equation 9-32
$$L_M = L_C + L_R$$

Where:

L_R = Total length of all ground rods in meters

For grids with ground rods in the corners, as well as along the perimeter and throughout the grid, the effective buried length, L_M, is expressed by Equation 9-33:

Equation 9-33

$$L_M = L_C + \left[1.55 + 1.22 \left(\frac{L_r}{\sqrt{L_x^2 + L_y^2}} \right) \right] L_R$$

Where:
L_r = Length of each ground rod in meters

9.10.5 Step Voltage (E_S)

Step voltages within a grid system designed for safe mesh voltages will be well within tolerable limits. This is because step voltages are usually smaller than touch voltages, and both feet are in series rather than parallel. Also, the body can tolerate higher currents through a foot-to-foot path since the current

does not pass close to the heart. The step voltage has to be less than the tolerable step voltage for the ground system to be safe.

The step voltage values are obtained as a product of the geometrical factor K_S, the corrective factor K_i, the soil resistivity (r), and the average current per unit of buried length of grounding system conductor (I_G/L_S):

Equation 9-34

$$E_s = \frac{r \cdot K_s \cdot K_i \cdot I_G}{L_S}$$

Where:

ρ = Soil resistivity, Ω-m
K_S = Spacing factor for step voltage, simplified method
K_i = Correction factor for grid geometry, simplified method
I_G = Maximum grid current that flows between ground grid and surrounding earth (including dc offset) in amperes
L_S = Effective buried conductor length in meters

For grids with or without ground rods, the effective buried conductor length, L_S , is expressed by Equation 9-35:

Equation 9-35

$$L_S = 0.75 \cdot L_C + 0.85 \cdot L_R$$

Where:

L_C = Total length of grid conductor in meters
L_R = Total length of ground rods in meters

The maximum step voltage is assumed to occur over a distance of 1 meter, beginning at and extending outside the perimeter conductor at the angle bisecting the most extreme corner of the grid. For the usual burial depth of 0.25 m < h < 2.5 m, K_s is expressed by Equation 9-36:

Equation 9-36

$$K_s = \frac{1}{p}\left[\frac{1}{2 \cdot h} + \frac{1}{D+h} + \frac{1}{D}\left(1 - 0.5^{n-2}\right)\right]$$

Where:

D = Spacing between parallel conductors in meters
h = Depth of ground grid conductors in meters
n = Geometric factor composed of factors n_a, n_b, n_c, and n_d

9.10.6   Ground Potential Rise (GPR)

In all the above situations for step, touch, and transferred voltage, the actual voltage potential encountered by the person involved is related to the ground potential rise of the grounding system above remote earth. This fact stresses the importance of keeping that value as low as possible.

Ground potential rise is the maximum electrical potential that a substation grounding grid may attain relative to a distant grounding point assumed to be at the potential of remote earth. This voltage, GPR, is equal to the maximum grid current times the grid resistance:

Equation 9-37
$$V_{GPR} = I_G R_g$$

Where:

V_{GPR} = Ground potential rise in volts
I_G = Maximum grid current in amperes (calculated in Section 9.5.4)
R_g = Ground grid resistance in Ω

Equation 9-38

$$R_g = \rho \left[\frac{1}{L_T} + \frac{1}{\sqrt{20A}} \left(1 + \frac{1}{1 + h\sqrt{20/A}} \right) \right]$$

Where:

h = Depth of the grid in meters
A = Area occupied by the ground grid in m^2 (calculated in Section 9.4)
L_T = Total buried length of conductors in meters
ρ = Soil resistivity in Ω-m (calculated in Section 9.3.2 , $\rho_{a(av1)}$)

Equation 9-38 shows that the larger the area covered by the grounding system and the greater the total length of the grounding conductor used, the lower will be the value of R_g for a given average earth resistivity. Equation 9-38 also shows that a low earth resistivity is very important in keeping R_g low.

Earth resistivity varies with the temperature and moisture content of the soil and whether the soil is frozen or unfrozen. For a given location, the earth resistivity is usually not controlled by the substation designer, although, in cases of very high soil resistivity, special treatments are sometimes used to help lower the value of ρ.

Whenever the product $I_g R_g$ results in a voltage below the tolerable touch voltage determined according to Section 9.8, there is no danger of ventricular fibrillation to most humans from body contact in any of the cases discussed. If the product $I_g R_g$ is in excess of allowable voltage values, then attention has to be given to elimination of possible exposure to transferred potentials and further investigation of touch and step potentials.

9.10.7   Design Modifications

If the calculated grid mesh and step voltages are much greater than the maximum touch and step voltages, then the preliminary design has to be modified. To reduce the grid mesh and step voltages, the following modifications can be tried:

1.   Decrease the mesh size by increasing the number of parallel conductors in each direction.

2.   Increase the thickness of the layer of surface rock. A practical limit to the depth of the rock may be 15.24 centimeters (6 inches).

3.   Limiting the total fault current, if feasible will decrease the GPR and all gradients in proportion. Other factors, however, will usually make this impractical. Moreover, if accomplished at the expense of greater fault clearing time, the danger may be increased rather than diminished.

Other effective measures can be taken to reduce the design mesh and step voltages. Their effects cannot be modeled using the simplified design equations and have to be modeled using a computer program such as EPRI SGSYS. These measures include the following:

1.   Place additional parallel conductors around the perimeter of the grid to produce smaller perimeter mesh. The smaller mesh will reduce the mesh and step voltages at the perimeter of the grid. The resulting unequally sized mesh throughout the grid violates one of the assumptions of the simplified design equations.

2.   Divert fault current to alternative paths. Diverting fault current is generally accomplished by ensuring that all power line overhead shield wires that enter the substation are connected to the ground grid. The split factor calculated according to Section 9.5.2 assumes that all shield wires have already been connected to the grid. Using larger shield wires or shield wires of a higher conductivity may divert additional fault current. For very small substation sites with high soil resistivities, this may be the only method that will bring the grid design into conformance with the safety criteria.

3.   If a two-layer soil model indicates that the bottom soil layer has a lower resistivity than the upper soil layer and lies deeper than 3.05 meters (10 feet), use longer ground rods to reach the lower resistivity layer.

4.   At a site with high-resistivity soil, drill a well and use it as a point of low resistance.

If all the above methods fail to obtain a grid design with safe mesh and step voltages, study and apply the following modifications where appropriate.

1.   Supplementing the grid conductors with deeply placed electrodes. This is required where the earth in which the grid conductors are buried is of resistivity too high to economically achieve a satisfactory resistance to remote earth. Such a situation may occur because of the natural character of the earth. High earth resistivity may also be seasonal because of the earth's drying out or becoming frozen. A decision on application of electrodes should necessarily be conservative because of the probabilistic nature of the problem. Seriously consider application of deep electrodes wherever relatively high resistivity in shallow earth will be experienced.

Rods are the most commonly used electrodes. Other types of electrodes, such as ground wells, are also used.

2.   Use of soil additives and treatments to increase the soil conductivity by reducing the resistivity of the soil. Refer to clause 14.5 of IEEE Std. 80 for additional information.

3.   Use of wire mats. It is feasible to combine both a surface material and fabricated mats made of wire mesh to equalize the gradient field near the surface. A typical wire mat might consist of copper-clad steel wires of No. 6 AWG, arranged in a 0.6 x 0.6 meter (24 x 24 inch) grid

pattern, installed on the earth's surface and below the surface material, and bonded to the main grounding grid at multiple locations.

4.   Wherever practical, use of a nearby deposit of low-resistivity material of sufficient volume to install an extra (satellite) grid. This satellite grid, when sufficiently connected to the main grid, will lower the overall resistance and, thus, the ground potential rise of the grounding grid. The nearby low-resistivity material may be a clay deposit or it may be a part of some large structure, such as the concrete mass of a hydroelectric dam.

5.   Barring access to certain areas, where practical, to reduce the probability of hazards to personnel.

9.10.8   Application of Equations for E_m and E_S

Several simplifying assumptions are made in deriving the equations for E_m and E_S. The equations were compared with more accurate computer results from cases with various grid shapes, mesh sizes, numbers of ground rods, and lengths of ground rods, and found to be consistently better than the previous equations. These cases included square, rectangular, triangular, T-shaped, and L-shaped grids. Cases were run with and without ground rods. The total ground rod length was varied with different numbers of ground rod locations and different ground rod lengths. The area of the grids was varied from 6.25 to 10,000 m^2 (67.27 to 107,639.10 ft^2). The number of mesh openings along a side was varied from 1 to 40. The mesh size was varied from 2.5 to 22.5 meters (8.2 to 78.8 feet). All cases assumed a uniform soil model and uniform conductor spacing. Most practical examples of grid design were considered. The comparisons found the equations to track the computer results with acceptable accuracy.

9.10.9   Use of Computer Analysis in Grid Design

Several reasons justify the use of computer analysis in designing the grounding system:

1.   Parameters exceed those of the simplified design equation.

2.   A two-layer or multi-layer soil model is preferred because of significant variations in soil resistivity.

3.   Uneven grid conductor or ground rod spacing cannot be analyzed using the approximate methods presented in this chapter.

4.   More flexibility in determining local danger points may be desired.

5.   The presence of buried metallic structures or conductors not connected to the grounding system introduces complexity to the system.

6.   The preliminary design can be optimized and analyzed.

9.10.10   Special Danger Points

9.10.10.1   Substation Fence Grounding: The grounding of the substation fence is critical because the fence is generally accessible to the public. The substation grounding design should be such that the touch potential on both sides of the fence is within the calculated tolerable limit of touch potential.

The substation fence should be connected to the main ground grid by means of an outer grid conductor installed a minimum of 0.91 meter (3 feet) (approximately one arm's length) outside the substation fence as shown in Figure 9-36. Connections to the outer grid conductor should be made at all corner posts and at line post every 12.92 to 15.24 meters (40 to 50 feet). The gateposts should be securely bonded to the adjacent fence as shown in Figure 9-36, detail A. It is recommended that all gates swing inward and be designed and installed to prevent an outward swing. If gates are installed with an outward swing, then the ground grid should extend a minimum of 0.91 meter (3 feet) past the maximum swing of the gate. The reasons to extend the ground grid to cover the swing of the gate are the same as the reason to install a ground conductor 0.91 meter (3 feet) outside the fence. The voltage above remote earth decreases rapidly as one leaves the substation grounding area. For example, if a person standing outside the substation grounding grid touches a fence or outward-swung gate under substation fault conditions, the resulting potential difference could be large enough to pose a serious danger.

9.10.10.2   Operating Handles: Equipment operating handles are a special circumstance because of the higher probability for coincidence of adverse factors, namely, the presence of a person contacting grounded equipment and performing an operation that can lead to electrical breakdown.

If the grounding system is designed conservatively for safe mesh potentials, then the operator should not be exposed to unsafe voltages. However, because of the uncertainty inherent in substation grounding design, a metal grounding platform (mat), connected to the operating handle should be placed where the operator should stand on it to operate the device regardless of whether the operating handle is insulated.

Considerations involved in the switch grounding platform ground conductor include the following:

1.   Proper grounding calculations and grid design should result in acceptable touch and step potential voltages without the additional grounding platform grounding. However, since the operation of the switch places the operator directly at risk when a substation fault occurs, additional precautions are needed. This includes adding switch grounding platforms and a 3- to 6-inch layer of clean crushed rock that covers the entire area inside the substation fence and extends 3 to 4 feet outside the substation fence to reduce the risk of electric shock.

2.   Switch grounding platform grounding is added to minimize the voltage between the switch operator's hands and feet in the event of a fault at the switch during manual operation.

3.   The basic methods to minimize the hand-to-foot voltage at the switch handle include the following:

    a.   Minimize the current that flows in the conductor that connects the equipment grasped by the hand and the surface that is stood on.

    b.   Minimize the resistance of the electrical connection between the hands and feet.

The grounding platform should be connected to the operating handle by a copper cable that connects to the operating handle and the grounding platform as shown in Figure 9-37.

PLAN
(NOT TO SCALE)

GATE BY-PASS
1'-6" BEYOND OPENED GATES

75'
APPROX.

3'-0" *

① ② ③ ④

ELEVATION A-A
(NOT TO SCALE)

1'-6" MAX
(TYPICAL)

GATE

FENCE

④ SPLIT BOLT OR
COMPRESSION-TYPE
CONNECTORS (TYPICAL)

3'-0" MAX,
(TYPICAL)

⑤ FLEXIBLE, TINNED,
COPPER BRAID,
1 1/2" X 3/16"

INSERT 2'-0" OF
SLACK IN WIRE
UNDER ROAD

① NO. 2 SOFT
DRAWN, SOLID,
BARE, TINNED
COPPER RISERS
(WEAVE THROUGH
FENCE FABRIC)

GROUNDING CONNECTOR
FOR ROUND POSTS

② PERIMETER GROUND GRID
(SEE NOTE 2)

③ GROUND ROD (TYPICAL)

UNDERGROUND
GROUNDING
CONNECTOR (TYPICAL) ④

8'-0" MIN

NOTES:

1 THE FENCE GROUND IS TO BE INTERCONNECTED WITH THE STATION GROUND BUS.

2. PERIMETER GROUND WIRE SHOULD BE CONTINUOUS CABLE CONNECTED TO FENCE POSTS, TO ALL GATE POSTS, AND TO ALL CORNERS.

3. WIRE TO BE LOOPED THROUGH GROUND ROD CLAMPS AND FENCE CLAMPS TO KEEP WIRE SPLICES TO A MINIMUM.

4. FOR OTHER REQUIREMENTS REFER TO S-6, RUS SPECIFICATIONS FOR GROUNDING IN STEAM-ELECTRIC GENERATING PLANTS AND ASSOCIATED STEP-UP SUBSTATIONS.

5. CONNECTIONS BETWEEN FENCE GROUND AND STATION GROUND BUS SHOULD BE AT INTERVALS SUCH AS TO LIMIT POTENTIAL GRADIENTS (STEP POTENTIALS) AND SHOULD GAVE ADEQUATE CURRENT-CARRYING CAPACITY FOR THE MAXIMUM FORESEEABLE GROUND FAULT CURRENT.

6. MINIMUM FENCE HEIGHT SHALL BE SEVEN FEET. THIS SHOULD NORMALLY CONSIST OF SIX FEET OF FABRIC AND A ONE-FOOT EXTENSION OF BARBED WIRE. RUS RECOMMENDS EIGHT FEET FOR THE FENCE HEIGHT; SEVEN FEET OF FABRIC AND A ONE-FOOT EXTENSION OF BARBED WIRE. WHERE LOCAL ORDINANCES PROHIBIT THE USE OF BARBED WIRE, THE FENCE FABRIC MUST BE INCREASED TO SEVEN FEET. BARBED WIRE SHOULD OVERHANG AWAY FROM THE SUBSTATION YARD.

* 3'-0" IS MINIMUM, 4'-0" IS RECOMMENDED.

LIST OF MATERIAL			
DRG REF	REQD	DESCRIPTION	ITEM
1		WIRE NO. 2 Cu, S, D, SOLID, BARE, TINNED, AS REQ'D	
2		SUBSTATION GROUNDING WIRE, AS REQ'D	SR
3		GROUND RODS, 8'-0" MIN. LGTH, AS REQ'D	GR
4		CONNECTORS AND CLAMPS, AS REQ'D	P
5		COPPER BRAID, FLEXIBLE, TINNED, 1 1/2" x 3/16"	

TYPICAL CHAIN LINK FENCE GROUNDING
SUBSTATION
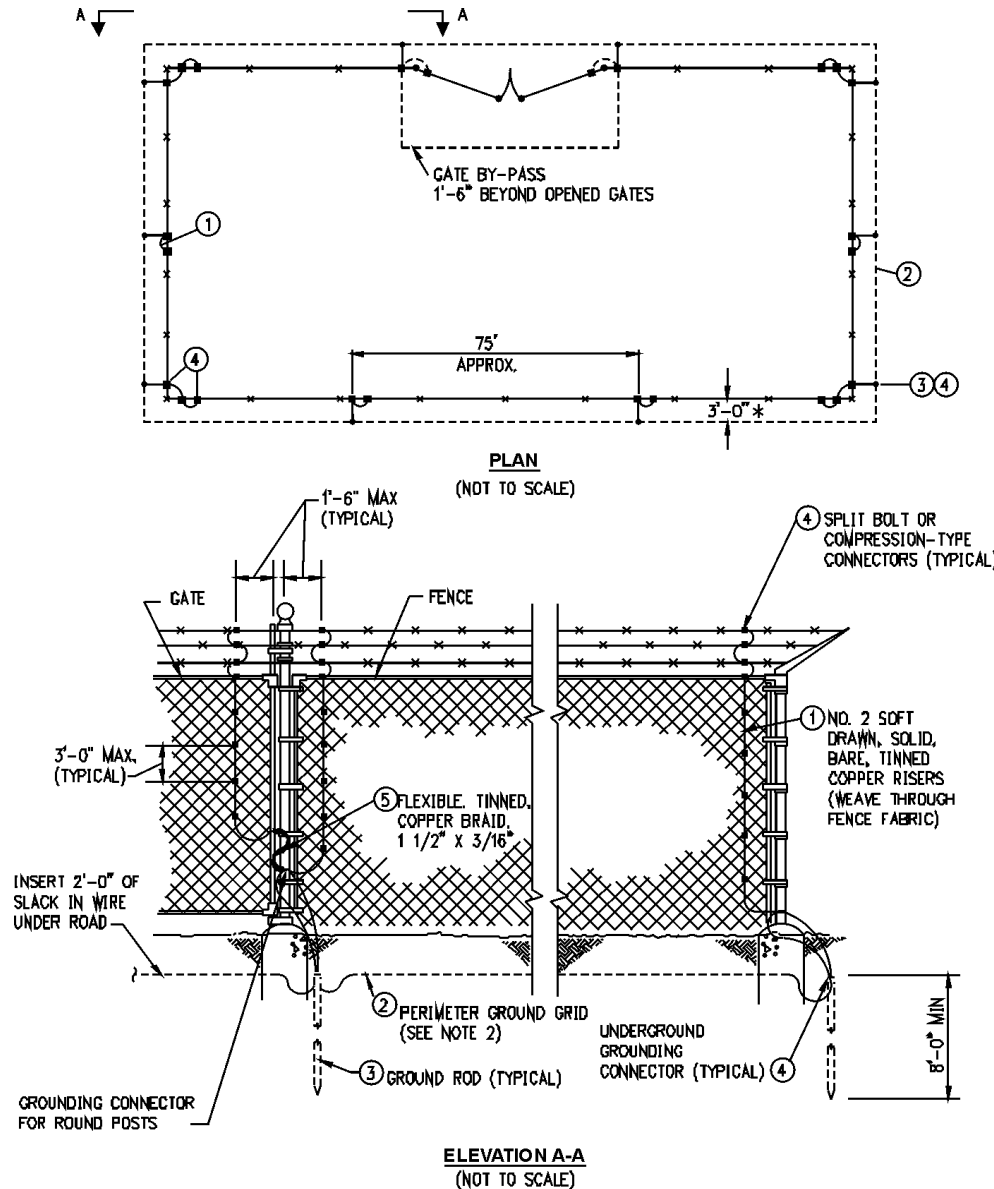
Figure 9-36: Typical Chain Link Fence

VERTICAL OPERATING PIPE

BRAID
(GROUNDING DEVICE
ON MULTI-REVOLUTION
GEAR CONTROL)

SWING HANDLE
(GEAR CONTROL ON
SOME SWITCHES)

STRUCTURE

CLAMP

SEE NOTE

CLAMP

OPERATOR'S
PLATFORM

CRUSHED
ROCK

TO
GROUND
GRID
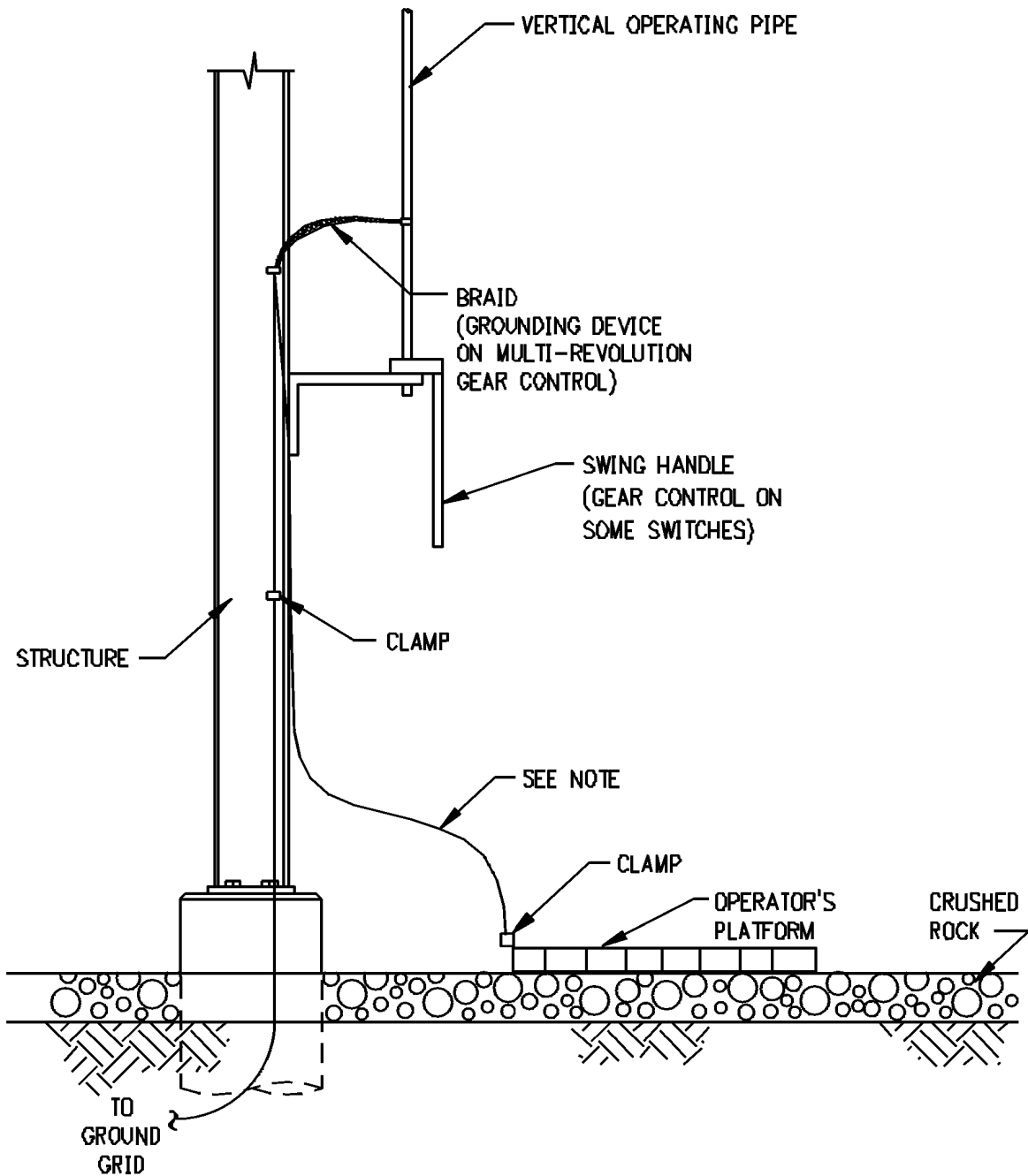
NOTE:
THIS CONDUCTOR HAS TO BE INSTALLED ABOVE GRADE FOR
VISUAL INSPECTION DURING ROUTINE SUBSTATION MAINTENANCE.

Figure 9-37: Typical Switch Grounding

Figure 9-37 provides a grounding system for a switch operator operating the switch handle. With no other ground cable connection to the grounding platform, minimal current will flow through the operator's body to the platform since it will be insulated from the earth and conductor because of the surface rock. The hand-to-foot voltage will be minimized and closely maintained with this connection. The grounding platform area needs to be kept clean of contamination and vegetation. If the grounding platform conductor to the switch handle breaks, then the contamination or vegetation touching the grounding platform can result in the grounding platform's potential being close to that of the ground grid, which is a less safe situation.

The design engineer should be familiar with the application of switch handle grounding and operator platform grounding by utilizing the latest available standard and publications including RUS document updates on this subject. The engineer also should develop a safety procedure checklist regarding all grounding aspects of the switch operator handle for the utility maintenance crew to follow before attempting to operate the switch.

9.10.10.3   Metallic Cable Sheaths: Metallic cable sheaths in power cable have to be effectively grounded to prevent dangerous voltages resulting from insulation failure, electrostatic and electromagnetic induction, flow of fault current in the sheath, and voltage rise during fault current flow in the substation ground system to which the sheaths are connected. Cable sheaths should be grounded at two or more locations: at cable terminations and at splices and taps. Control cable shields are not intended to carry significant current and thus should only be grounded at one end. Where any cable sheath may be exposed to excessive ground current flow, a parallel ground cable should be run and connected to both ends. IEEE Std. 80 provides more information on metallic cable sheath grounding.

9.10.10.4   Surge Arrester Grounding: Surge arresters are designed to pass surge energy from lightning and switching transients to ground and so are frequently subjected to abnormal current flow to ground. They have to be reliably grounded to ensure protection of the equipment they are protecting and to minimize high potential gradients during operation.

The surge arrester grounds should be connected as close as possible to the ground terminals of the apparatus to be protected and have as short and direct a path to earth as practical. Arrester leads should be as free from sharp bends as practical. The tanks of transformers and steel or aluminum structures may be considered as the path for grounding arresters, provided effective connections can be made and secure multiple paths are available. Where there can be any question regarding the adequacy of these paths, it is recommended that a separate copper conductor(s) be used between the arrester ground terminal and the substation grounding grid.

9.10.11 Investigation of Transferred Voltage

Transferred voltage contact may be considered a special case of the "touch" contact. A potential hazard may result during a ground fault from the transfer of potentials between the ground grid areas and outside points by conductors such as communication circuits, low-voltage neutral wires, conduit, pipes, rails, metallic fences, etc. A person standing within the substation touches a conductor grounded at a remote point, or a person standing at a remote point touches a conductor connected to the substation grounding system. Here, the shock voltage may be essentially equal to the full voltage rise of the grounding system under fault conditions and not the fraction of this total that is encountered in the usual "step" or "touch" contacts.

It is impractical and often impossible to design a grounding system based on the transferred voltage. Hazards from these external transferred voltages are best avoided by using isolating or neutralizing devices and by treating and clearly labeling these circuits, pipes, etc., as being equivalent to *live* lines.

Carefully examine the presence of any situations involving possible transferred voltage and take steps to eliminate or avoid them. Clause 17.9 of IEEE Std. 80 discusses many such situations in greater detail.

9.10.12 Effect of Sustained Ground Currents

After the grounding design has been established as safe for the maximum ground fault current at the appropriate clearing time, check step and touch voltages for sustained ground currents.

Sustained currents are those currents below the setting of protective relays that may flow for a long time. Currents produced through the body as a result of these long-duration currents should be below safe let-go values. Some sustained faults above the let-go current, but below the fibrillation threshold, may cause asphyxiation from prolonged contraction of the chest muscles. However, it would not be practical to design against lesser shocks that are painful but cause no permanent injury.

9.11 REFERENCES

Biddle Co., *Getting Down-To-Earth*, 5th ed. Trooper, Pa.: AVO International, 1998.

EPRI, Substation Maximum Earth Current Computation (SMECC).

IEEE Std. 80, "Guide for Safety in AC Substation Grounding."

IEEE Std. 81, "Recommended Guide for Measuring Ground Resistance and Potential Gradients in Earth."

IEEE Std. 81.2, "Measurement of Impedance and Safety Characteristics of Large, Extended or Interconnected Grounding System (Part 2)."

IEEE Std. 837, "Qualifying Permanent Connections Used in Substation Grounding."

RUS IP 202-1, "List of Materials Acceptable for Use on Systems of RUS Electrification Borrowers."

CHAPTER 10
INSULATED CABLES AND RACEWAYS

10.1   GENERAL

This chapter covers the application and selection of low-voltage, high-voltage, and special cables and raceways for cable protection. Low-voltage cables are defined as those operating at 600 volts and below, high-voltage as those operating above 600 volts, and special cables as those operating in the radio frequency spectrum, i.e., 30 kHz and above.

See ANSI/IEEE Std. 525, "Guide for Selection and Installation of Control and Low-Voltage Cable Systems in Substations," for additional data on substation cables.

10.2 600-VOLT CABLE

10.2.1   Circuit Requirements

Circuits of 600 volts can be divided into two main categories: power circuits and control circuits. Substation power circuits are those supplying power to cooling fans, insulating oil pumps, air compressors, apparatus heaters, luminaires, and similar three-phase and single-phase loads. Voltage levels and connections vary depending on the application. These can be:

1.   480/240 volt, three-phase delta connected
2.   480/277 volt, three-phase wye connected
3.   208/120 volt, three-phase wye connected
4.   240 volt, three-phase delta connected
5.   240/120 volt, three-phase closed or open delta connected with one phase center-tapped
6.   240/120 volt, single-phase three-wire

The relative merits of these six alternatives are covered in detail and illustrated in Chapter 15, AC and DC Auxiliary Systems.

Substation control circuits are those that execute a command to and/or indicate the status of a piece of apparatus such as a circuit breaker. Control circuits also include those concerned with currents and voltages for relaying and similar purposes. These circuits usually operate at less than 300 volts and may be dc or ac. Typical examples are current and potential circuits for protective relays and metering devices, and trip or close commands to automatic protective devices. Communication and supervisory control and data acquisition (SCADA) system circuitry fall under the category of control circuits.

In spite of the usually lower voltage level of control circuitry, a minimum insulation level of 600 volts should be specified. Cable of 600 volts is more readily available than 300-volt cable, and the small, if any, price differential is generally not an equitable trade for the additional protection provided by the 600-volt insulation. An exception to the above rule may be a requirement of several thousand feet of low-voltage (48-volt) circuitry. In this instance, consider 300-volt insulation as a possible economic advantage.

10.2.2   Conductors

Insulated power and control circuit conductors of 600 volts may be copper or aluminum, solid or stranded. Because of the lower termination reliability and lower ampacity of aluminum, copper is generally preferred.

Power circuit conductors should be No. 12 AWG minimum size. Stranded conductors are easier to handle and lend themselves to compression or bolted lugs and connectors. RUS Bulletins 50-71, "RUS Specification for 600 V Underground Power Cable," and 50-30, "RUS Specification for 600 V Neutral-Supported Secondary and Service Drop Cables," contain information on 600-volt power cables.

Control circuit conductors, because of low ampacity requirements, are often smaller than No. 12 AWG. Stranding can be such as to permit flexibility. A typical No. 12 AWG control conductor could be made up of 19 strands of No. 25 AWG copper whereas a power conductor would be made up of 7 strands of No. 19 AWG.

Stranding of individual conductors is basically concentric and rope stranding. Concentric cable stranding is defined as a cable consisting of a central wire surrounded by one or more helically laid wires with the lay direction the same for all layers. A rope-stranded cable consists of groups of concentric cables. Concentric cable has a more nearly circular cross section, permitting the best centering of the conductor within the insulation. General-use 600-volt cable is manufactured concentric strand. Rope-stranded power cable is available as flexible and extra flexible, and the cost is such as to preclude use for 600-volt circuits. An exception would be the use of very short lengths of a large-diameter cable, where the flexibility makes termination easier, or where excessive conductor movement is inevitable. Avoid such situations if possible.

10.2.3   Conductor Configurations

Insulated conductors are manufactured as single- or multi-conductor cables, shielded or non-shielded, and with or without armor.

Control circuit conductors are usually specified as multi-conductor cables. This has the basic advantage of one specific multi-conductor circuit laying in one place instead of several places. This could be the case with a four-conductor current transformer circuit.

10.2.3.1   Color Coding: Control circuit multi-conductor cables can be purchased with all wires colored black or the wires color coded. Color coding should be by the Insulated Cable Engineers Association (ICEA) methods.

Colored insulation compounds with tracers repeated in regular sequence (color coding) is the most widely used method. Color coding methods are specified in ICEA Publication S-73-532/NEMA WC57, and the color coding sequence shown in Tables E-1 and E-2 of that publication may be used, depending on the application. Table E-1 is used when the installation is not required to meet *NEC* requirements. Table E-2 can be used for all installations, including those required to meet the *NEC*. The preferred method is Table E-2, which is reproduced as Table 10-1.

Color coding for substation control circuits, even single conductor circuits, is recommended. Standard codes can be established for circuit functions and individual wire functions. For example, a blue wire standardized as a "trip" wire and a red wire standardized as a "close" wire for power circuit breaker control duplicates the color practice for pilot lights on control panels indicating breaker status. In

Table 10-1: Color Sequence. Ref. ICEA, App. E, S-73-532/NEMA WC57, Table E-2.

Conductor Number	Background or Base Color	Tracer Color	Conductor Number	Background or Base Color	Tracer Color
1	Black	—	19	Orange	Blue
2	Red	—	20	Yellow	Blue
3	Blue	—	21	Brown	Blue
4	Orange	—	22	Black	Orange
5	Yellow	—	23	Red	Orange
6	Brown	—	24	Blue	Orange
7	Red	Black	25	Yellow	Orange
8	Blue	Black	26	Brown	Orange
9	Orange	Black	27	Black	Yellow
10	Yellow	Black	28	Red	Yellow
11	Brown	Black	29	Blue	Yellow
12	Black	Red	30	Orange	Yellow
13	Blue	Red	31	Brown	Yellow
14	Orange	Red	32	Black	Brown
15	Yellow	Red	33	Red	Brown
16	Brown	Red	34	Blue	Brown
17	Black	Blue	35	Orange	Brown
18	Red	Blue	36	Yellow	Brown

addition, color coding can assist greatly in "ringing out" control circuits, especially in large substations. It is recommended that, for additions to a non-coded substation, a color coding scheme be established for the addition.

All-black control wires may be used for a strictly temporary control installation of minor size at the option of the engineer.

Telephone and telemetering circuits where used should utilize the 25-pair-count color code method as specified in ICEA Std. S-56-434, RUS Bulletin 1753F-205, "RUS Specification for Filled Telephone Cables (PE-39)," and RUS Bulletin 1753F-208, "RUS Specification for Filled Telephone Cables with Expanded Insulation (PE-89)." Except for lighting circuits, power conductor color coding need not be used. Circuits can be tagged for phase indication and wire number after "ringing out." Lighting circuit conductors are specified single conductor with the neutral being white and a feed or switch wire black. It is recommended that three-way switch dummy wires be coded red and blue, reserving green for a bonding conductor where required.

10.2.3.2 **Shielding**: Conductor shielding of control circuit cables is specified basically to prevent a false signal from being inductively coupled to a control circuit from an energized high-voltage bus or from the switching operation of high-voltage disconnecting equipment, capacitor switching, coupling capacitor voltage transformers, ground potential rise differences, and other switching-type operations. As a general rule, a 230 kV or lower substation with electromechanical protective relays need not include shielded control cables. However, if solid-state relays or supervisory remote terminal units are planned, a study with reference to control cable shielding should be made. See ANSI/IEEE Std. 525, "Guide for Selection and Installation of Control and Low-Voltage Cable Systems in Substations," for additional details.

Conductor shielding, where required for control circuit conductors, consists of a metallic covering completely enclosing the conductor bundle. Individual conductor shielding is available but is not applicable at 230 kV and below. Where shields are used, they should be grounded as outlined in Chap-

ter 9, Grounding. For grounding methods that have been found to be effective in shielding control cables, also see Chapter 9.

10.2.4 Conductor Insulation and Jackets

Insulation is a very important parameter in wire or cable selection. Base insulation selection on the properties of life, dielectric characteristics, resistance to flame, mechanical strength and flexibility, temperature capability, and moisture resistance. Insulation types applicable to substation conductors are:

- Ethylene Propylene Rubber   EPR
- Cross-Linked Polyethylene   XLPE
- Tree Retardant Cross-Linked Polyethylene   TR-XLPE

The Oxygen Index (O.I.) of a plastic-insulated wire or cable is a measure of the fire propagation resistance of the material as determined by the Fire Test of ANSI/IEEE Std. 422. Air normally contains 21 percent oxygen; hence, a material with an oxygen index below 21 will burn readily in air. A cable O.I. of 27 or greater is generally high enough to pass the IEEE Fire Test.

Table 10-2 lists the basic properties of the insulating materials under consideration.

Table 10-2: Properties of Cable Insulating Materials

Material	Max. Oper. Temp. °C (°F)	Oxygen Index	Cost (Low- Moderate- High)
EPR	90 (194)	20	M
XLPE	90 (194)	18	M
TR-XLPE	90 (194)	18	M

Minimum acceptable insulation thickness shall be as specified by the RUS Bulletins 50-71, "RUS Specification for 600 V Underground Power Cable," and 50-30, "RUS Specification for 600 V Neutral-Supported Secondary and Service Drop Cables."

Since no single insulating material fulfills all requirements, engineering judgment is required for selection of insulation for 600-volt substation wiring. Economic judgment should also be exercised as to standardization.

The *National Electrical Code (NEC)* contains tables showing temperature ratings and location restraints of insulation. The design engineer should also use the wealth of information available to him from cable manufacturers' data.

Jackets are used over individual insulated wires or over multi-conductor cables to provide protection against mechanical damage, sunlight exposure, moisture, oil, acids, alkalis, and flame. Some insulating materials used on single-conductor circuits, notably lighting circuits, have the required protection without the use of additional jackets. An example is *NEC* Type TW, which is a 60°C, flame-retardant, moisture-resistant thermoplastic insulation suitable for conduit, tray, or trench installation.

Jacket materials currently in use on 600-volt cables are Polyethylene and Polyvinyl Chloride (PVC). Other jacket materials are also commercially available.

10.2.5   Cable Sizing

In substation design, the important element of cable sizing is current carrying capacity. Voltage drop is a secondary factor except for current transformer circuits, tripping circuits, and long conductor runs. Check for voltage drop of the longest circuit, using the conductor size and the current capacity dictated. Manufacturers' data usually include voltage drop tables. Where such data are unavailable, calculate the voltage drop. The voltage drop in a conductor should not be large enough to cause faulty operation of the device being fed by the conductors. For power circuits, a 3 to 5 percent loss is tolerable with reasonable regulation. Electric motors are generally rated for satisfactory operation at ±10 percent voltage; electric heating elements will operate satisfactorily within the same range. If any doubt exists, contact the equipment manufacturer to determine voltage tolerances applicable.

Also consider voltage drop in current transformer circuits. As can be seen from Figure 10-l, with a C400 transformer, No. 14 AWG leads are required. With a C200 transformer, No. 9 AWG leads are required. In other words, calculate current transformer circuit voltage drop to select a cable size that allows the current transformer ratio error to remain within acceptable limits. Given a certain current transformer class furnished with equipment, the leads have to be sized for the given current transformer. A C200 current transformer can maintain 200 volts across the secondary terminals and hold the ratio error within 10 percent when 20 times full load current is applied.

Conductor selection based on current-carrying capacity is made by computing the current required to serve the load. The wire or cable is selected from applicable Articles of the *NEC* or from manufacturers' data. This applies to both control and power conductors. The *NEC* contains examples of branch and feeder circuit size calculations.

The current-carrying capacity of a given size conductor is not a constant. The ampacity varies depending on the installation condition. Conductors for use in free air are rated higher than those in conduit. More than three conductors in a conduit also lowers the current-carrying capacity of each individual conductor.

In general, conductor insulation short-circuit capability for 600-volt substation service need not be considered. As an example, No. 9 AWG copper with XLPE insulation may carry up to 5000 amperes for 2 cycles without conductor failure.

The cooperative should establish standard conductor sizes for the cooperative's particular system, for example, 4/c No. 9 for current transformer circuits, 5/c No. 12 for potential circuits, 8/c or 10/c No. 12 for multipurpose control, and 1/c No. 12 for miscellaneous relay interconnections, etc. Standardization can result in cost savings through quantity purchases and, if standard sizes are stocked, long lead times for maintenance work can be eliminated.

10.2.6   Segregation of Control Cables

Low-voltage circuits providing instrumentation and control functions in a substation are subject to failures and damage. The installation of these circuits to minimize damage, upon failure, to adjacent circuits is one of the prime concerns in substation design. The cooperative should decide, based on operating history, the substation voltage level where such damage may result in reduced reliability.

GROUND FAULT 20X CURRENT OR 24000A

1200A
FULL LOAD

1200:5

V_S

500' – #9
500' – #14

V_L

BURDEN 25VA @ 5A
OR 1 OHM R
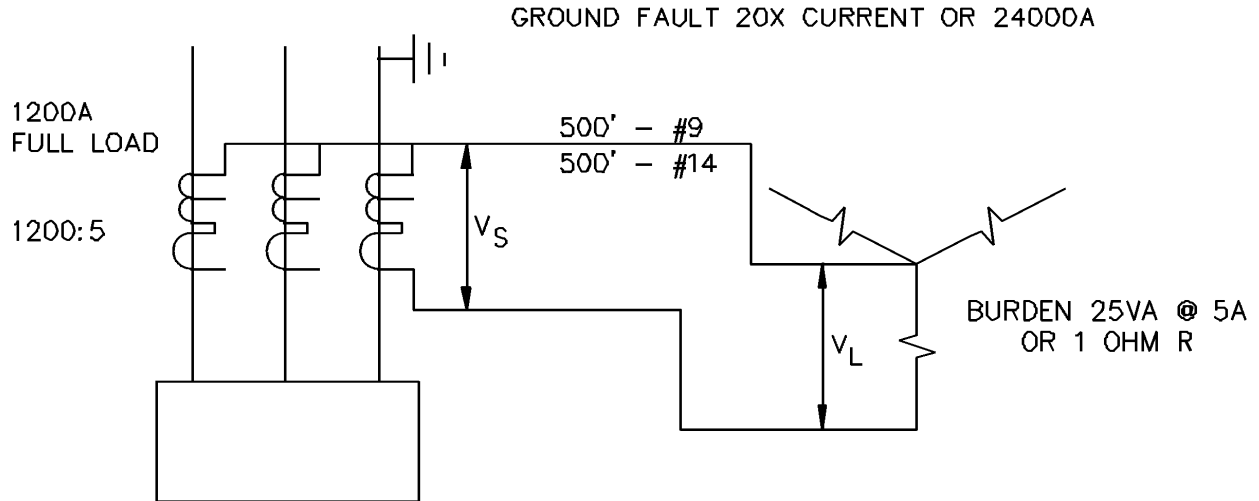
I_F = 100A

R = 0.79 OHMS/1000"−#9

R = 2.5 OHMS/1000"−#14

IR DROP #9   100*0.79 = 79V

#14   100*2.5 = 250V

V_L 100*1.0 = 100V

V_S #9   179V

V_S #14   350V

Figure 10-1: Voltage Drop for Current Transformer Circuits

A method of approaching a solution to the possible damage situation is through circuit isolation or segregation. This method approaches a solution because materials, methods, and costs dictate design practices that may fall short of providing perfect isolation. The best design is a balance of reliability and cost.

To prevent damage to adjacent cables, the following guidelines should be applied at least in 230 kV and higher substations. Operating history may dictate use at 115 kV or lower substations.

    a.   Isolate circuits having the greatest exposure to primary voltage such as potential and current transformer secondaries.
    b.   Group wiring from one power circuit breaker position and isolate it from other breaker positions.
    c.   Group wiring from one bus differential.

    d.   Group wiring from one transformer differential.
    e.   Route ac circuits on one side of a relay or control panel and dc circuits on the other side.
    f.   Group metering, alarm, and low-voltage (120-volt) control house circuits.
    g.   Divide trays with grounded metal barriers.
    h.   Where practical, run control cables perpendicular to high-voltage buses. If this is not possible, maintain maximum physical separation.
    i.   Isolate primary protection circuits from secondary circuits or backup circuits.

Segregation of control cables also simplifies original circuit testing, maintenance procedures, and substation additions and constitutes "good housekeeping."

From these suggested guidelines and from operating history, the cooperative can establish control cable segregation standards for its system. All substations on a system should be the same, promoting ease of testing and maintenance and possibly an increase in reliability.

10.2.7 <u>Installation Considerations</u>

Cable failures occurring during precommission testing and/or shortly after substation service has begun can often be traced to insulation failure caused by construction abuse or design inadequacy. Insulation can be damaged by excessive pulling tension during construction. Conduit elbows selected with too small a radius could result in insulation flattening during installation.

Bending radius for general-use power and control cables is dependent on insulation type, number of conductors, size of conductors, and shielding. The cooperative should establish standards for its system based on cable manufacturers' recommendations.

Cable damage can also occur through the entry of moisture at an unsealed end. When a cut is made from a reel, seal the reel end against moisture. Seal cable ends prior to connections. Lugs for use in moist locations should be shrouded type.

Construction specifications should state that unlagged reels are not to be handled by lift trucks. Properly store cable at all times to prevent damage. Common-sense handling by concerned personnel can prevent cable damage both in storage and in the field.

Construction specifications should also require the following:

    a.   Wherever possible, cables need to be run from outdoor equipment to the control house without splices.
    b.   Control cable splices should be made indoors at least 5 feet above the floor.
    c.   Taps and splices in trays should not be buried under other cables.
    d.   Splices should never be buried in earth or pulled in conduits or ducts.
    e.   Wires, splices, and taps in metal junction boxes should never be under cover pressure. An adequately sized box should be specified.
    f.   Specifications and layouts should be designed to avoid sharp corners and also to provide adequate space for pulling cables into place with a minimum of rigging.

Where relatively large conductors, #1/0 and above, are used in three-phase circuits, and the quantity justifies it, consider ordering three or four conductors on a single reel. Such a consideration is an obvious installation labor-saving decision.

It is advisable, when a length is cut from a reel, that the new reel length be recorded. Inventory is possible when this is done, and a project has less chance of delay because of lack of material control.

Cable terminations should allow enough slack to prevent tension on the terminating lugs.

10.3 POWER CABLE OVER 600 VOLTS

10.3.1 Medium-Voltage Shielded Power Cable (2 kV up to 35 kV)

The use of medium-voltage power cable for distribution circuits is generally limited to the underground cables supplying power to the station service transformers, bus ties, and underground feeders that exit the substation. Medium-voltage cables have solid extruded dielectric insulation and are rated from 1,000 to 35,000 volts. These single- and multiple-conductor cables are available with nominal voltage ratings of 5, 8, 15, 25, and 35 kV. Figure 10-2 illustrates the typical construction of medium-voltage shielded power cable. RUS Bulletin 50-70, "RUS Specification for 15 kV and 25 kV Primary Underground Cable," contains additional information on 15 kV and 25 kV power cable.
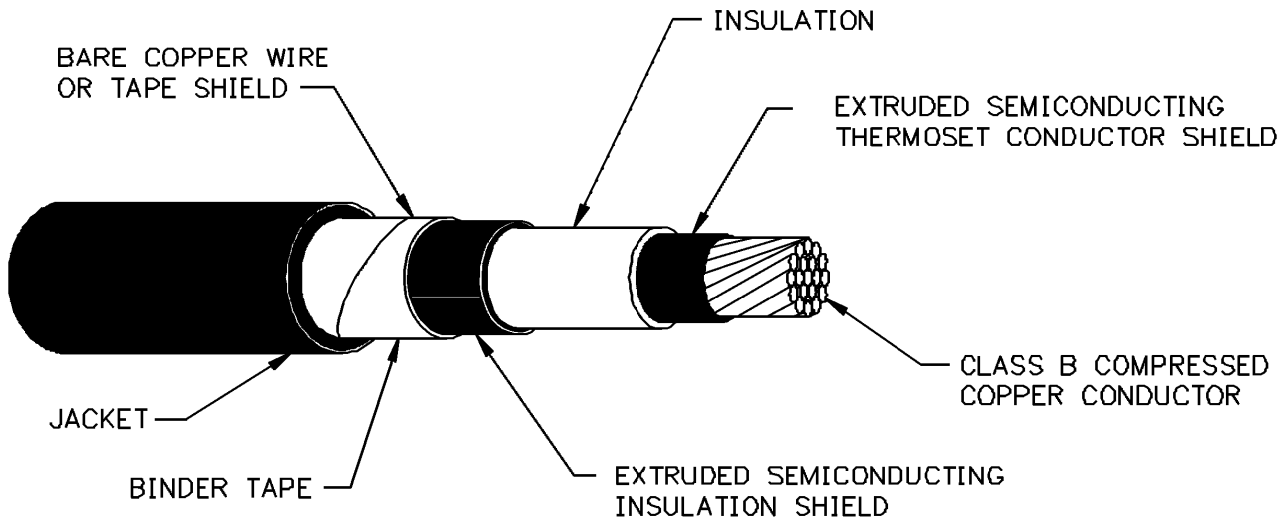
Figure 10-2: Construction of Shielded Power Cable

10.3.2 Conductors

Medium-voltage power cable may be copper or aluminum with either a solid or stranded cross section. The primary benefit of stranded conductors is improved flexibility. Stranded conductors can also be compressed, compacted, or segmented to achieve desired flexibility, diameter, and load current density. For the same cross-sectional area of a conductor, the diameter differs among solid and the various types of stranded conductors. This consideration is important in the selection of connectors and in methods of splicing and terminating. For the most part, stranded conductors are used almost exclusively for medium-voltage power cable.

10.3.3 Conductor Shield

The conductor shield is usually a semi-conducting material applied over the conductor circumference to

shield out the conductor contours. The shield prevents the dielectric field lines from being distorted by the shape of the outer strands of the conductor. This layer also provides a smooth and compatible surface for the application of the insulation.

10.3.4   Insulation

A very important parameter in cable selection is the insulation. Insulation selection should be based on service life, dielectric characteristics, resistance to flame, mechanical strength and flexibility, temperature capability, and moisture resistance. Common insulation types applicable to medium-voltage cables are:

- Ethylene Propylene Rubber   EPR
- Cross-Linked Polyethylene   XLPE
- Tree Retardant Cross-Linked Polyethylene   TR-XLPE

EPR and TR-XLPE are the most common insulating compounds for medium-voltage power cables. Minimum acceptable insulation thickness shall be as specified by the RUS Bulletin 50-70, "RUS Specification for 15 kV and 25 kV Primary Underground Power Cable." The *NEC* contains tables showing temperature ratings and location restraints of insulation types. Also use the wealth of information available from cable manufactures' data.

Since no single insulation material fulfills all requirements, engineering judgment is required for selection of insulation for medium-voltage cable. Also factor in the economics of cable standardization.

10.3.5   Insulation Shield

The insulation shield is a two-part system composed of an auxiliary and a primary shield.

An auxiliary shield is usually a semi-conducting nonmetallic material over the insulation circumference. It has to be compatible with the insulation. A commonly used auxiliary shield consists of an extruded semi-conducting layer partially bonded to the insulation. The primary shield is a metallic shield (wire or tape) over the circumference of the auxiliary shield. It has to be capable of conducting the sum of "leakage" currents to the nearest ground with an acceptable voltage drop. In some cases it also needs to be capable of conducting fault currents. The shield has several purposes:

- Confine the electric field within the cable.
- Equalize voltage stress within the insulation, minimizing surface discharges.
- Protect cable from induced potentials.
- Limit electromagnetic or electrostatic interference (radio, TV etc.).
- Reduce shock hazard (see Chapter 9 for proper grounding of the shield).

10.3.6   Jackets

The cable may have components over the insulation shielding system to provide environmental protection. This material can be an extruded jacket of synthetic material, metal sheath/wires, armoring, or a combination of these materials. Selection of jacket material should be based on the conditions in which the cable will be operated. The following considerations should be taken into account:

- Service life
- Temperature capability

- Requirements for mechanical strength and flexibility
- Abrasion resistance
- Exposure to sunlight, moisture, oil, acids, alkalis, and flame

A common jacket type applicable to medium-voltage cable is:

- Linear Low Density Polyethylene   LLDPE

Since no single jacket material fulfills all requirements, engineering judgment is required for selection of a jacket for medium-voltage cable. Also factor in the economics of cable standardization.

10.3.7 Cable Voltage Rating

The voltage rating of a cable is based, in part, on the thickness of the insulation and the type of the electrical system to which it is connected. General system categories are as defined by the Association of Edison Illuminating Companies (AEIC).

10.3.7.1   100 Percent Level: Cables in this category may be applied where the system is provided with protection such that ground faults will be cleared as rapidly as possible, but in any case within 1 minute. While these cables are applicable to the great majority of cable installations on grounded systems, they may also be used on other systems for which the application of cables is acceptable, provided the above clearing requirements are met when completely de-energizing the faulted section.

10.3.7.2   133 Percent Level: This insulation level corresponds to that formerly designated for ungrounded systems. Cables in this category may be applied in situations where the clearing time requirements of the 100 percent level category cannot be met, and yet there is adequate assurance that the faulted section will be de-energized in one hour or less. They may also be used when additional insulation thickness over the 100 percent level category is desirable.

10.3.7.3   173 Percent Level: Cables in this category should be applied on systems where the time required to de-energize a grounded section is indefinite. Their use is also recommended for resonant grounded systems. Consult the cable manufacturer for insulation thickness.

10.3.8 Conductor Sizing

In substation applications, the most important element of cable sizing is the current-carrying capacity that is required to serve the load. Take into account both continuous and non-continuous loads and any emergency overload that the cable will be required to carry. Voltage drop is a secondary factor in very large installations with long cable runs. Check for voltage drop of the longest circuit, using the conductor size and the current capacity indicated. Manufacturers' data include voltage drop tables. Where such data are not available, calculate voltage drop. The voltage drop in a conductor should not be large enough to cause faulty operation of the device being fed by the conductors. For medium-voltage circuits, 3 to 5 percent regulation is generally tolerable with reasonable regulation. If any doubt exists, contact the equipment manufacturer to determine the applicable voltage tolerances.

Conductor selection based on current-carrying capacity is made by computing the current required to serve the load. Select the cable from the applicable articles of the *NEC* and the manufacturers' data. The current-carrying capacity of a given size conductor varies depending on the cable installation (in air,

underground, conduit, cable tray etc.). Make sure the correct articles and tables in the *NEC* are applied when sizing the cable for current-currying capacity for the cable installation being considered.

Also take into account the available three-phase and phase-to-ground fault current levels when selecting the conductor size and shield requirements. In some cases, the minimum size conductor determined by the fault current level requirements would result in a larger conductor size than was determined by the load current-carrying requirements.

After calculating the available fault current levels and time required to clear the fault, look at the cable manufacturer's data to determine the minimum size conductor and shield requirements for the application.

10.3.9   Terminations and Splices

Cable terminations are required for cables 1 kV and above. When shielded power cables are terminated and the insulation shield is removed, an abrupt change in the dielectric field results. Consequently, there is a concentration of electrical stresses along the insulation surface at the point where the shielding ends. These non-uniform stress concentrations can cause insulation breakdown and cable failure.

To prevent cable failure, the cable has to be terminated in such a way as to eliminate the non-uniform voltage stresses. This is accomplished by placing a stress cone over the cable insulation. The stress cone has to be prefabricated.

Shielded power cables terminated indoors or in a controlled environment require only a stress relief cone. When a cable is terminated outdoors, it is exposed to various contaminants, many of which are conductive and/or corrosive. These contaminants may cause flashover or arcing from the insulated conductor to the nearest adjacent conductor. This would result in degradation of the termination. Therefore, extended creep path is required in addition to stress relief when terminating shielded power cable outdoors. This is accomplished by adding skirts to the termination to increase the creepage distance.

Splices are mainly used when it is necessary to join two cables at manholes and pull boxes. The basic concept to be remembered in splicing two cables is that the cable splice is in fact a short piece of cable that is fabricated in the field. As such, the splice needs to have the same components as the cables. For shielded cables, the design of the splice needs to be compatible with the cable materials and also provide the continuation of each cable component in order to keep voltage stresses to a minimum.

Currently, prefabricated termination kits and splice kits are the preferred practice because of the savings in time and materials.

10.3.10   Cable Segregation

According to the *NEC*, medium-voltage power cables should be segregated from low-voltage power, instrument, and control circuits. See the applicable articles in the *NEC* for additional information.

10.3.11   Installation Considerations

The type of medium-voltage power cable selected should be suitable for all environmental conditions that occur in the area where the cable is installed. Prior to purchase and the actual installation of the cable, consider the following:

- Cable operating temperatures in substations are normally based on 40°C ambient air, or 20°C ambient earth temperature. Give special consideration to cable installed in areas where ambient temperatures differ from these values.
- Whether the cable is direct buried; installed in duct banks, below-grade conduits, or trenches; or installed in above-grade cable trays or conduits, the cable should be rated and UL approved for the particular cable installation. The cable should also be suitable for operation in wet and dry locations. If in doubt about the application, consult the cable manufacturer.
- The service life of the cable selected in most cases should be at least equal to the design life of the substation.
- Cables installed in cable trays or other raceway systems where flame propagation is of concern should pass the UL Std. 1072 or ANSI/IEEE Std. 383 flame tests.
- The cable should maintain its required insulating properties when exposed to chemical environments.

Cable failures occurring during pre-commission testing and/or shortly after substation service has begun can often be traced to insulation failure caused by construction abuse or design inadequacy. Insulation can be damaged by excessive pulling tension or by exceeding the minimum bending radius during construction. The bending radius depends on insulation type, number of conductors, size of conductors, and type of shielding. The cooperative should establish standards for the system based on the cable manufacturers' recommendations.

Cable damage can also occur through the entry of moisture at an unsealed end. When a cut is made from a reel, seal the reel against moisture. Seal cable ends prior to termination.

10.3.12 High-Voltage Power Cable (69 kV up to 230 kV)

Underground transmission cable usage in the United States is very small: less than 1 percent of overhead line mileage. The highest underground cable voltage that is commonly used in the United States is 345 kV, and a large portion of this cable is high-pressure fluid-filled pipe-type cable. Extruded dielectric cables are commonly used in the United States up to 230 kV, with up to 500 kV in service overseas.

Underground transmission cable is generally more expensive than overhead lines. Because of all the variables (system design, route considerations, cable type, raceway type, etc.), it has to be determined case by case if underground transmission cable is a viable alternative. A rule of thumb is that underground transmission cable will cost from three to twenty times the cost of overhead line construction. As a result of the high cost, the use of high-voltage power cable for transmission and subtransmission is generally limited to special applications caused by environmental and/or right-of-way restrictions. For this reason, few applications will be justified for the cooperative's system. If underground transmission cable is going to be considered, an engineering study is required to properly evaluate the possible underground alternatives.

See EPRI's *Underground Transmission Systems Reference Book* for additional information on high-voltage power cable.

10.4 SPECIALIZED CABLE

Substation cable in this category consists of coaxial cables for low-frequency (30 kHz to 500 kHz) use in carrier communications and for ultra-high-frequency (300 MHz to 3 GHz) use in microwave systems.

Coaxial cables for carrier communications are available with surge impedance (Z_o) of 50 and 75 ohms, 50 ohms being the most common. Because of the low power requirements of carrier systems, cable power rating need not be considered. The primary consideration is jacket material. Some jackets contain plasticizers that, when exposed to weather, leach into the center insulator, seriously increasing power losses and making replacement necessary in approximately five years.

Non-contaminating jackets are available where the life of the jacket is 20 years or more. The cost differential of a few cents per foot is worth the added reliability.

Typical coaxial cable for carrier communication use is RG-213/U having a non-contaminating jacket and nominal Z_o of 50 ohms, but, depending on the application, a different coaxial cable may be required.

Coaxial cable for microwave communication (3.0 GHz and below) is a part of a more sophisticated system. Losses and power rating should be taken into consideration.

Microwave coaxial cable, 50 ohms Z_o, is available with air dielectric and foam dielectric. Air dielectric cable, to prevent moisture entry, is pressurized with inert gas, usually nitrogen. At a given frequency, cable with air dielectric has less attenuation than with foam dielectric, but the pressure system has to be monitored. Foam dielectric is the preferred cable. The transmitter may have to be specified with power to overcome the cable attenuation, but this can be minimized with attention to equipment location and by keeping coaxial leads short. A detailed selection procedure for microwave cable is covered in manufacturers' handbooks.

If spectrum space below 3.0 GHz is unavailable, the cooperative wishing to use microwave communications may have to apply for a higher frequency. Above 3.0 GHz, coaxial cables exhibit far too much attenuation for practical use, necessitating use of wave guides. Wave guide application is beyond the scope of this bulletin.

10.5   RACEWAYS

10.5.1   Function

Raceways, in the form of conduits, trays, and trenches, are used in substations to provide protection and electrical segregation of cables.

Historically, raceway materials evolved as materials evolved, brought on mainly by increasing labor costs. Steel conduit was followed by fiber and cement asbestos conduit. The lower weight and easier tooling was the main advantage. Block trenches and cast-in-place concrete trenches followed. These trenches, while about the same cost as concrete-encased ducts, reduce the potential for cable damage since the cables are simply laid in the trench. Precast concrete trench, knocked down for field assembly, then became available. Plastic conduit followed and is a stock item with many electrical suppliers. Other materials for raceway use will likely appear on the market.

10.5.2   Economics

The economics of a raceway system for a substation hinge on a cost/benefit ratio. A balance between required reliability and the cost of such reliability should be established.

The design costs of various systems generally will not vary appreciably. More design will be required for an underground duct system than would be required for precast trench for a large substation.

Delivery charges to the site for various materials, site handling costs, and installation labor costs are the major items to be considered in an economic evaluation. Simplicity of expansion, ease of testing, maintenance and cable replacement, personnel safety, security, and appearance may, in part or in total, be factors for consideration when alternative systems are being studied.

In addition to items discussed in this guide, use the many available trade publications as necessary.

10.6   UNDERGROUND RACEWAYS

Since all underground systems offer the same "out-of-the-way" appearance and the same degree of security, these criteria are irrelevant when comparing one system to another.

In this guide, the use of underground metallic conduit for other than ½- and ¾-inch lighting circuits is not considered. Labor and material costs prohibit such an installation.

Underground methods available are:

   a.   Direct-buried cable
   b.   Direct-buried conduit
   c.   Concrete-encased conduit (duct bank)
   d.   Cable trenches (partially underground)

10.6.1   Direct-Buried Cable

Direct-buried cable, although the least costly underground method, should generally be avoided except for lighting branch circuits, and then only in small installations. Circuit reliability can be continually threatened by excavation. Metallic armored cables can minimize this damage and potential personnel hazard but sacrifice the lower cost.

Most control and power cables, with insulation suitable for any below-grade installation, are suitable for direct burial. However, without a surrounding case (conduit), the cables are subject to damage by burrowing animals.

Trenches for direct-buried cables are shown in RUS Bulletin 1728F-806, "Specification and Drawings for Underground Electric Distribution" drawings UR2 to UR2-2, UR2-3 to UR2-5, UR2-NT and UR2-ST inclusive.

Advantages

   a.   The width of the excavation is minimized.
   b.   Cable can be laid in with no pulling damage.
   c.   Conduit labor and material cost are at a minimum (only equipment risers are required).
   d.   "In-line" handholes or manholes are not required.

Disadvantages

   a.   Testing is done prior to backfilling the trench, leaving cable exposed to potential damage.
   b.   "Dig-in" damage is possible.

c. Trench bottom and backfill material has to be carefully inspected. Original excavated material may be unsatisfactory for backfill, requiring purchase and delivery of proper material.
d. Electrical circuit segregation, without separate or wide trenches, may not be possible.
e. Cable replacement or cable additions require additional excavation.
f. Neutral corrosion is possible.

10.6.2 <u>Direct-Buried Conduit</u>

In a small distribution substation, direct-buried nonmetallic conduit for control and power cable including lighting circuits should offer the most economical underground system or cost/benefit ratio.

Select non-metallic conduit with a wall thickness suitable for direct earth burial. Procure fittings for the conduit, whether plastic, fiber, or cement asbestos, from the manufacturers of the conduit. This will ensure component compatibility.

Except for equipment risers, avoid conduit bends to limit cable pulling tension. Pulling tension should be limited to 454 kg (1000 lbs) when pulled with a basket grip. Control cables with conductors No. 16 AWG and smaller should be limited to 40 percent of this value or lower if recommended by the manufacturer.

In the design phase, calculate conductor pulling tension using Equation 10-1:

Equation 10-1
$$T = lwf$$

Where:
  T = Tension, in kilograms (pounds)
  l   = Length of conduit run, in meters (feet)
  w = Unit weight of cable, in kilograms/meter (pounds/foot)
  f   = Coefficient of friction (0.5) (f may be decreased by using pulling lubricants)

Use this relation in the computation and compare the worst case to the maximum allowable tension. Reduce excessive lengths with handholes or manholes to provide pulling points.

Use Equation 10-1 to determine the pulling tension for a given conduit length. Given the tension, the maximum length (L) can be found using Equation 10-2:

Equation 10-2
$$L = T/wf$$

Direct-buried conduit banks can be installed in the same way as concrete encased (see Section 10.6.3) less the concrete. The cable derating factors discussed in Section 10.6.3 have to be applied.

<u>Advantages</u>

a. "Dig-in" damage is reduced.
b. Excavation, conduit placement, and backfilling can be one operation.
c. Electrical circuit segregation is possible.
d. Burrowing animal damage to cable is prevented.
e. Expansion is eased.

     f.   Cable replacement is eased.

Disadvantages

     a.   Cables are pulled; hence, care is required to prevent damage.
     b.   Manholes or handholes may be required.
     c.   Backfill material requires inspection as to suitability.

10.6.3   <u>Concrete Encased Conduit (Duct Bank)</u>

Concrete-encased duct bank is decreasing in popularity, giving way to cable trenches. In spite of the growing popularity of cable trench use in substations, cases exist where duct banks have to be used, either with or without concrete encasement. Cases in point could include conduits passing under heavy traffic roads, posing a barrier to equipment movement, or blocking natural drainage. Resolve this or similar situations when determining the preferred raceway system.

When several cables are placed in the same duct bank, the operating temperature of the inner cables could exceed the safe operating temperature of the cable insulation. To prevent this situation, the current-carrying capacity of the cable is de-rated, based on the *NEC*. Make sure the correct articles and tables of the *NEC* are applied when determining the current-carrying capacity for concrete-encased duct bank installations. The engineer can change the current-carrying capacity of the cable significantly by selecting different duct bank configurations and spacing, etc.

The ampacity values indicated in the *NEC* tables were calculated as detailed in "The Calculation of the Temperature Rise and Load Capability of Cable Systems" by J.H. Neher and M.H. McGraph. The *NEC* Ampacity Tables cover most applications, but if the duct bank configuration, spacing, etc., is not included in the *NEC* Ampacity Tables, calculate the duct bank ampacity of the cable by using the Neher and McGraph method. Either do the calculations by hand or use one of the many available computer programs.

To determine the approximate duct bank ampacity of the cable, calculate it by multiplying the normal ampacity or load of the cable by a position factor. Figure 10-3 cites examples of these position factors.

For an underground installation, excavation work should be specified as called for in Chapter 6. The designer should indicate a pitch of 10.2 centimeters per 30.5 meters (4 inches per 100 feet) for duct drainage.

There are two types of duct bank: built up and tier. The built-up (monolithic) method consists of laying conduits on fabricated plastic spacers, sized to the conduit outside diameter and desired separation. Base spacers allow for 7.6 centimeters (3 inches) of concrete below the bottom row of conduits (ducts). Intermediate spacers are placed on the top of the bottom and succeeding layers of ducts to the desired height. Spacers are placed on both sides of couplings, the couplings being staggered along the run. When the entire bank is constructed and inspected to ensure ducts are aligned and continuous, the entire duct bank is enclosed with machine-mixed concrete grout, usually a 1:6 mix. The monolithic pour of the built-up method is usually used with very careful supervision of all steps to eliminate the faults prevented by tiering. Figure 10-4 illustrates monolithic duct bank construction.

95	95
83	83
83	83
95	95

AVERAGE = 89

93	79	93
79	64	79
93	79	93

AVERAGE = 83.5

90	77	90
73	55	73
71	52	71
70	47	70
70	47	70
71	52	71
73	55	73
90	77	90

AVERAGE = 70

100	100
100	100

AVERAGE = 100

93	93
80	80
78	78
76	76
76	76
78	78
80	80
93	93

AVERAGE = 82

91	77	91
75	60	75
75	60	75
91	77	91

AVERAGE = 78

89	71	71	89
71	48	48	71
71	48	48	71
89	71	71	89

AVERAGE = 70

85	65	62	62	65	85
65	38	31	31	38	65
62	31	20	20	31	62
62	31	20	20	31	62
65	38	31	31	38	65
85	65	62	62	65	85

AVERAGE = 51

RELATIVE WATT LOSSES FOR INDIVIDUAL DUCTS AND BANKS OF DUCTS PER FOOT OF CABLE FOR SAME TEMPERATURE RISE (PERCENTAGE OF 2 BY 2 BANK)

$$\text{POSITION FACTOR} = \sqrt{\frac{\text{RELATIVE LOSS FOR ANY DUCT}}{\text{AVERAGE LOSS}}}$$

Figure 10-3: Duct Bank Position Factors
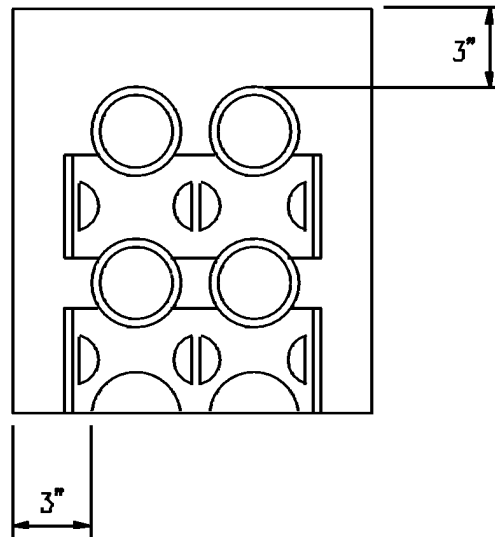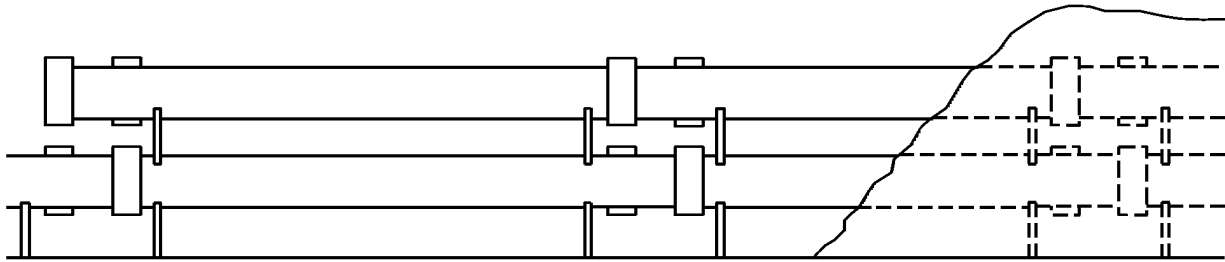
Figure 10-4: Monolithic Duct Bank Construction

The tier method consists of placing a 7.62 cm (3-inch) layer of concrete in the bottom of the trench. After an initial set, the bottom row of ducts is laid with separation maintained by wooden or metal combs with the crossbar thickness equal to the required vertical separation. Concrete is poured, screened to the comb tops. After partial set, the combs are removed and the process repeated to the full height of the duct bank. Figure 10-5 lists the amount of concrete required for various duct combinations. The tier method is obviously more costly, but concrete voids, duct separation, and duct floating are prevented.

Advantages

    a.   Permanent
    b.   Improbable accidental cable damage by "dig-in"
    c.   Ease of cable replacement
    d.   Possible electrical circuit segregation
    e.   Impossible burrowing animal damage
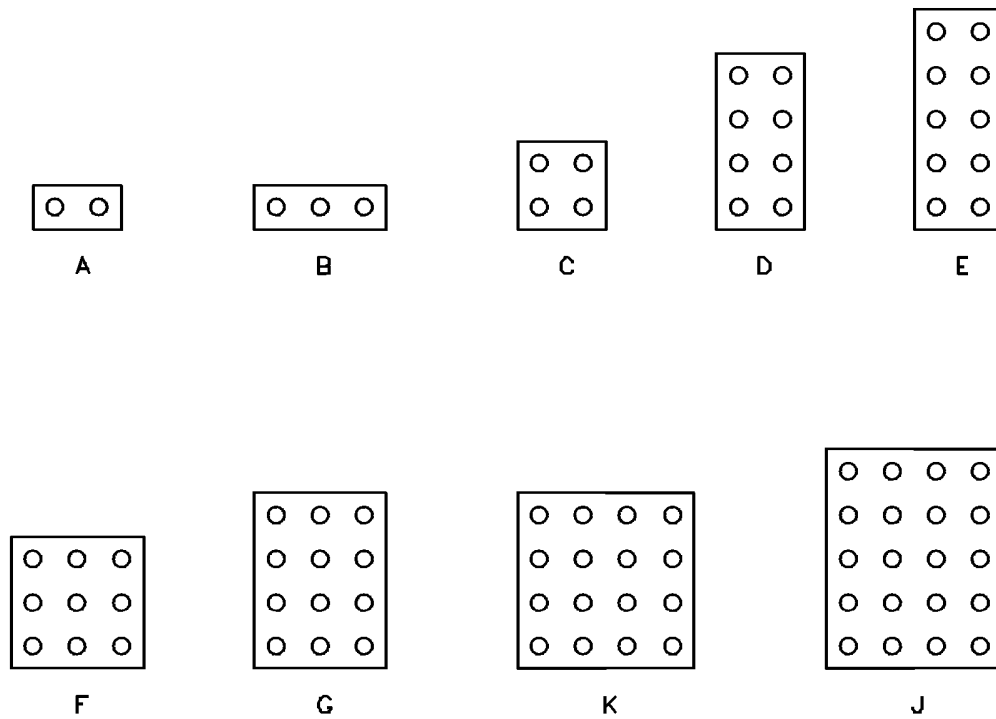
TABLE OF APPROXIMATE CUBIC YARDS OF GROUT FOR 100 TRENCH FEET IF FORMATIONS WITH 3 INCHES OF GROUT ENVELOPE ON BOTH SIDES, THE TOP, AND THE BASE.

DUCT FORMATION	A	B	C	D	E	F	G	H	J
NUMBER OF DUCTS	2	3	4	6	8	9	12	16	20

1-1/2 INCH SEPARATION OF CONDUIT

	2	2.6	3.3	3.6	4.6	5.7	5.9	7.3	8.9	10.5
	3	3.2	4.1	4.5	5.9	7.3	7.6	9.4	11.8	13.7
SIZE OF	3-1/2	3.4	4.5	4.9	6.5	8.0	8.5	10.6	13.0	15.4
CONDUIT	4	3.7	5.0	5.4	7.2	8.9	9.5	11.7	14.4	17.2
	4-1/2	4.0	5.3	6.0	7.9	9.8	10.3	12.9	16.0	19.0
	5	4.4	5.8	6.5	8.6	10.7	11.3	14.1	17.5	21.0

Figure 10-5: Tier Duct Bank Construction Cubic Yards of Grout for 100 Trench Feet

Disadvantages

    a.   Cost
    b.   Consideration of substation expansion
    c.   Required derating of certain cables in large duct banks

10.6.4   Cable Trenches

The most significant advantage of cable trench use is the saving of labor during cable installation plus the absence of cable pulling damage. Trenches are becoming the most acceptable cable installation method, particularly in large installations.

Cable trenches may be constructed in several ways.

10.6.4.1   **Block Construction:** If block construction is planned for a control house, economics may indicate block trench. Core or solid, concrete or cinder block is satisfactory for cable trench. Covers can be fabricated from checkered plate aluminum or lightweight concrete. Figure 10-6 illustrates suggested construction.

10.6.4.2   **Cast-in-Place Concrete Construction:** This form of trench construction can be justified in a large substation where many foundations are being constructed and the necessary tradesmen and materials are readily available. Fabrication is similar to the block cable trench illustrated in Figure 10-6.

10.6.4.3   **Precast Concrete Trench:** Depending on manufacturing plant locations and related freight cost, precast trench may present an attractive alternative for a reasonably large installation. Field labor should be substantially lower than the block or cast-in-place options. Precast trench is supplied with lightweight concrete covers in manageable lengths, depending on trench width. Figure 10-7 shows a typical design. Transitions are also available for vehicular crossings and building entrances.

A very high degree of layout flexibility is available to the engineer. Direction changes are usually limited to 90°, but, with the cable lay-in benefits, cable damage in construction should be nonexistent. The engineer can, with different trench widths, lay out a complete trench system without costly manhole construction, also avoiding substation roadways.

Electrical segregation cannot be as complete with a cable trench system as in a multiple-conduit duct bank system. In general, cable trenches are constructed without bottoms or floors. This is done to eliminate floating or frost heaving with consequent possible misalignment. Cables are placed on a 10.2- to 15.2-centimeter (4- to 6-inch) bed of fine sand. French drains can be placed at selected intervals to drain the trench of stormwater.

Advantages

    a.   Cable is laid in.
    b.   Cable replacement or addition is simplified.
    c.   Expansion is unlimited.
    d.   Electrical segregation is possible to a limited degree.
    e.   Layout does not require manholes.
    f.   A high degree of installation flexibility is possible.

TURN CORE BLOCK—CONDUIT ENTRY

ELEVATION

PLATE
COVER

SEGREGATION BARRIER

BLOCK

TO EQUIP.
HANDHOLE

CONC. OR BLOCK
FOOTING (OPTIONAL)

SECTION
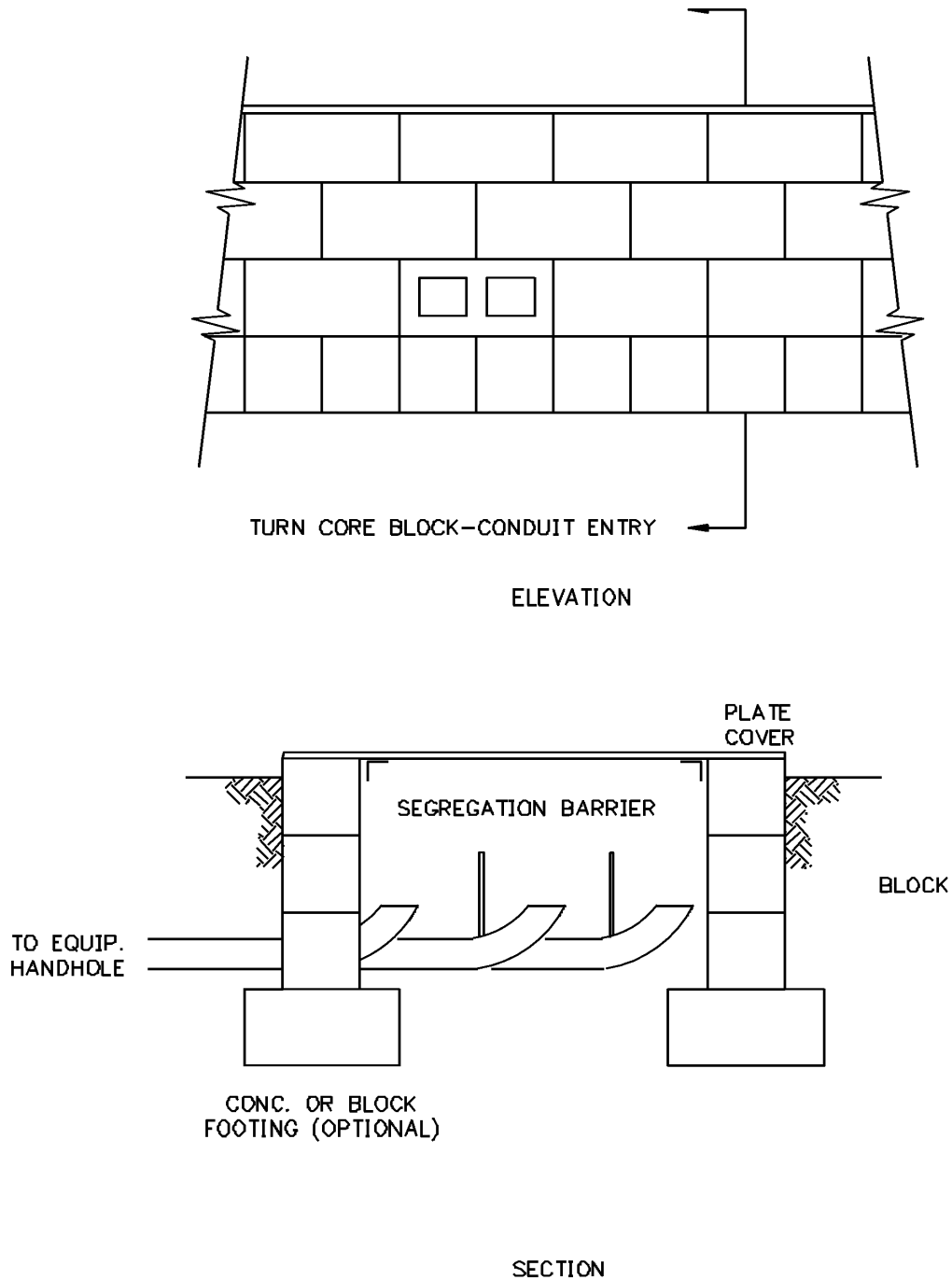
Figure 10-6: Block Trench, Cast Concrete Similar

Disadvantages

    a.   It does not prevent cable damage from burrowing animals and rodents.
    b.   Care has to be exercised to prevent covers from falling into the trench and damaging cable.
    c.   Vehicular traffic over trenches has to be prevented.
    d.   It can be a possible drainage barrier.

ELEVATION

CONC. COVER

SAND

SIDEWALL

BRACKET−5" O.C.

SECTION
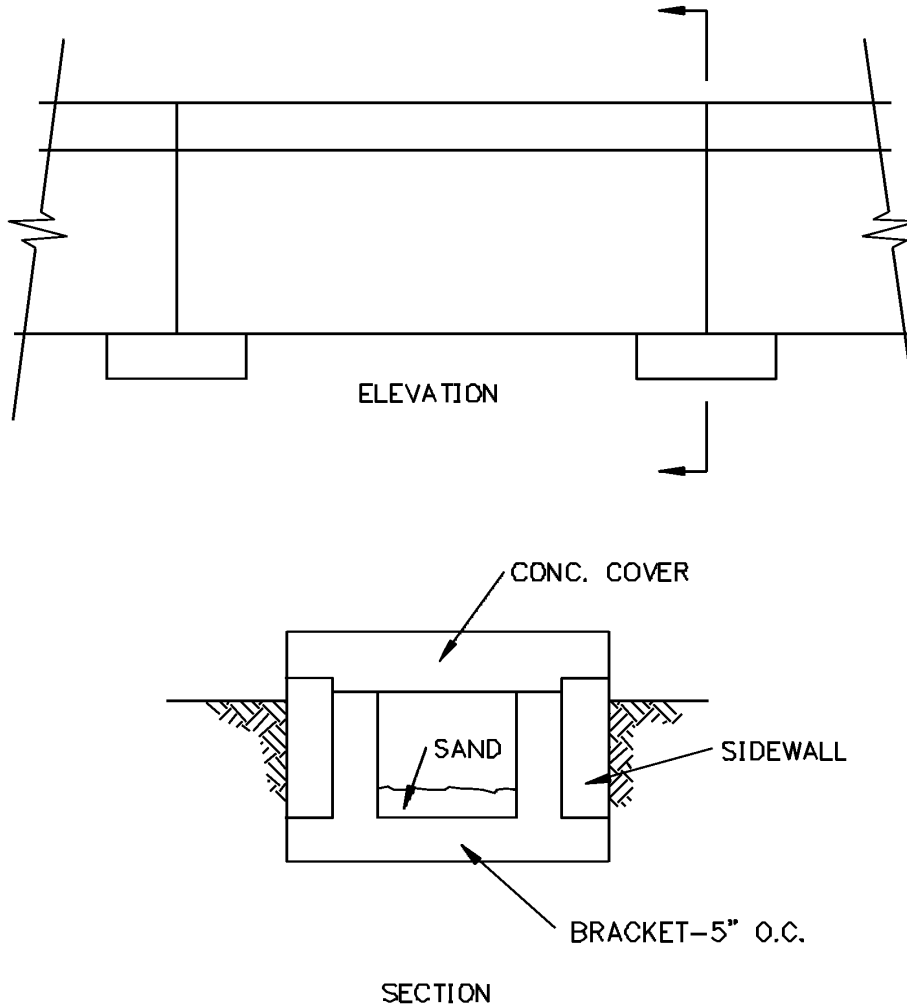
Figure 10-7: Pre-cast Cable Trench

10.6.5   Manholes

A companion item to some underground raceway systems is the manhole. Generally used in conjunction with below-grade duct banks, a manhole serves as a pulling and splicing point for cable runs, as a point to turn a duct line, and as a place to provide contraction and expansion of power conductors.

In light of the high construction costs even with precast units, and the ease of design and substantially lower cost of a total trench design, details of manholes will not be considered in this guide.

10.6.6   Handholes

Unlike manholes, handholes have a definite place in substation design. A handhole is essentially a miniature manhole installed approximately 0.61 meter (2 feet) below grade and measuring about 0.37 meter square (2 feet square). It serves as a pulling point for cables in a direct-burial conduit system. To

prevent floating, no bottom or floor is provided. This feature also allows easy conduit entry. A split metal cover or a lightweight concrete cover with knockouts is recommended.

The cooperative, depending on handhole usage, may elect to design forms and produce handholes. An outside small business firm could also be contracted to perform this service.

Figure 10-8 shows a suggested handhole design the cooperative can size to its particular requirements.

CONDUIT UP
TO EQUIPMENT

SPLIT METAL
COVER

ACCESS PART   FIXED PART

WIRE-REINFORCED
CONCRETE

WIRE BAND FOUR SIDES
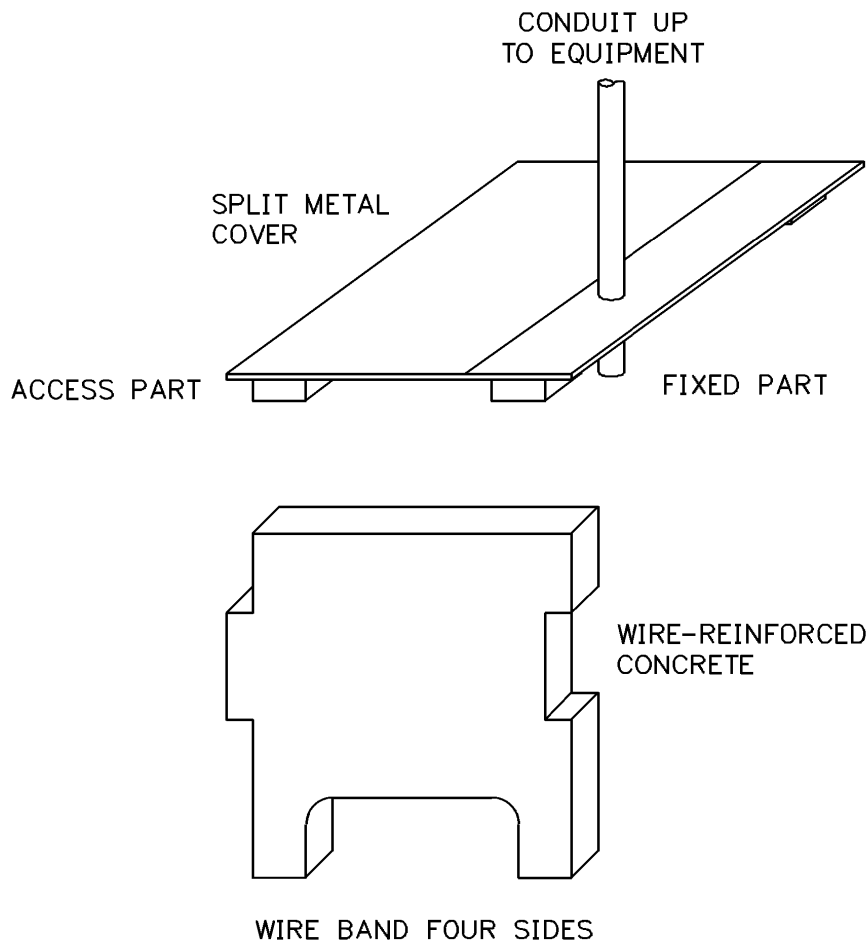
Figure 10-8: Suggested Handhole Design

10.7   RACEWAY COMBINATION

In all but the simplest installation, the designer will be confronted with combinations of the below-grade systems outlined in this chapter. Such combinations are the usual practice in substation design.

The specific combinations used in a given substation could possibly vary by geographic location. The most common system is one using cable trench, direct-buried conduit, handholes, and conduit rises. Figure 10-9 shows a typical system.
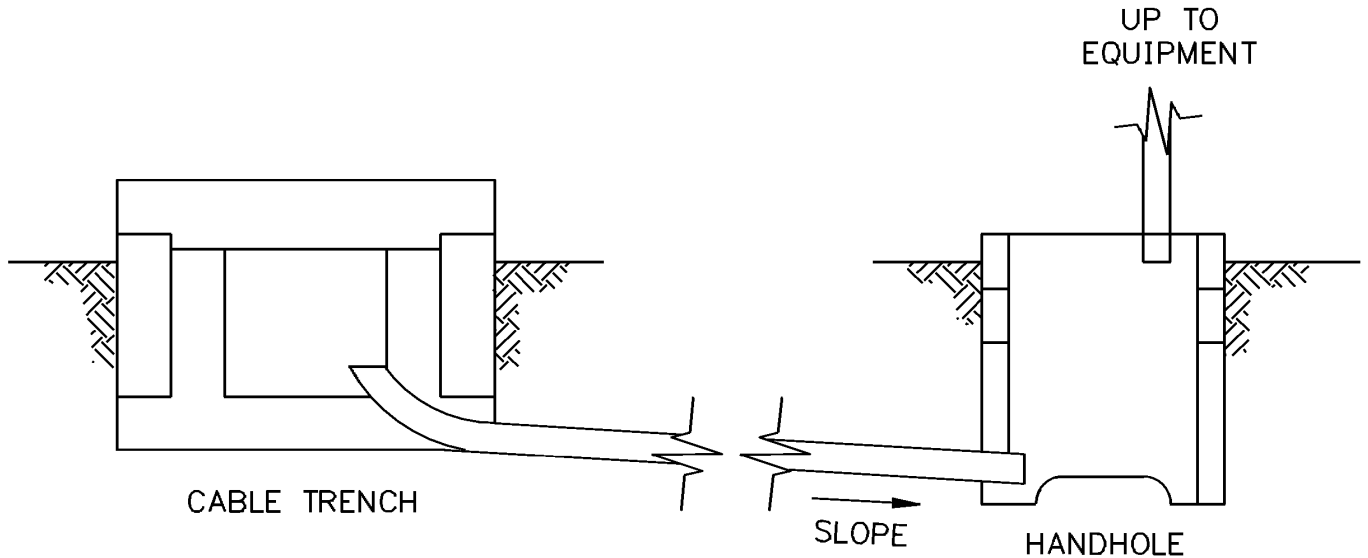
Figure 10-9: Trench to Handhole Conduit Installation

10.8   SUMMARY—UNDERGROUND RACEWAYS

If direct-buried cable is under consideration for a small installation, it should be recognized that a treated plank over the cable can offer some cable protection. Additionally, markers are available to indicate the cable route. The best protection against accidental dig-in is to maintain accurate, up-to-date drawings and set up a control system for all excavation within a substation enclosure.

Precast concrete duct sections are available under various trade names. These products make excellent raceways. However, determine site handling costs since the weights of the raceway components are high.

The concrete-encased duct system will find limited use in all but the very largest substations, and then under heavy axle-bearing roads. Heavy-wall, direct-burial, PVC conduit, 91.44 cm (36 inches) below a substation road surface will successfully withstand most substation vehicular traffic, depending on soil conditions.

The possibility of burrowing animals causing cable damage in trenches has been mentioned. With a knowledge of the area, take this situation into account when selecting site surface stone size and depth. The animal problem can be eliminated with adequate surface preparation. For guidance, see CRN's *Animal-Caused Outages* (Project 94-5).

Trapping or low points of below-grade conduits should be avoided in the design phase.

Make use of the many handbooks and other material available from vendors of raceway materials.

10.9   OVERHEAD RACEWAYS

In cases where buried raceway systems are impossible or unnecessary, above-grade raceways can be considered.

Available overhead raceways are:

a.   Cable tray
b.   Cable duct
c.   Plastic conduit
d.   Metal conduit
e.   Above-grade cable trench

10.9.1 Cable Trays

Cable trays offer ease of installation and circuit segregation within one tray. Pay attention to mounting details to prevent weather damage. Substation structures and/or specially designed support structures can be used.

Specify solid-bottom tray with expanded metal covers to prevent bird nesting. Consider access for equipment removal in the design phase.

10.9.2 Cable Duct

Cable duct consists of cable tray fitted with wooden blocks to properly space and support power conductors, in the 600- to 15000-volt range. Application in a substation would be limited to incoming or exiting distribution circuits.

10.9.3 Plastic Conduit

Plastic conduit and fittings are available from several manufacturers to meet the requirements of the *NEC*. Installation of this conduit has a labor advantage over steel since 4-inch steel weighs 14.9 kilograms per meter (10 pounds per foot) as compared to plastic weighing 3.0 kilograms per meter (2 pounds per foot). An adequate variety of fittings and bends is available, and joining is done with a cement. Threading is not required. Support requirements are outlined in the *NEC*.

10.9.4 Metal Conduit

Metal conduit comes in three types: electrometallic tubing (thin wall), galvanized steel (heavy wall), and aluminum.

Thin wall is limited to 2 inches in diameter, and fittings are expensive. The 2-inch size weighs 0.21 kilograms per meter (0.14 pounds per foot) as compared to 4.9 kilograms per meter (3.3 pounds per foot) for steel. Gland-type fittings are available to provide weather tightness.

Galvanized steel conduit, available in trade sizes from ½ to 6 inches, will provide the best mechanical protection for control and power cables. However, labor cost is high. Cutting, threading, and bending require tools not usually owned by tradesmen. The best application in a substation for this conduit is for serving lighting and convenience outlets with conduit clamped to structural members. Outdoor fittings and luminaires are threaded for ½- and ¾-inch rigid conduit. Aluminum conduit offers weight advantage in large sizes. Additionally, if each phase is installed in a separate conduit, aluminum will not heat up as will steel. Aluminum conduit should not be installed below grade, either for direct burial or concrete encasement, because of possible corrosion damage.

10.9.5   Above-Grade Cable Trench

A cable trench of block, cast-in-place, or precast concrete construction is satisfactory for above-grade raceways. Construction would be identical to a below-grade trench. In the case of precast construction, the "bracket" would have a ½-inch threaded insert, and the sidewalls each would have a half hole on each end. A ½-inch bolt and square washer would hold the wall in place in lieu of backfill. This construction method is not recommended where ground is subject to severe frost movement.

10.10 SUMMARY—OVERHEAD RACEWAYS

Where underground cable placement is not possible and substation control is sophisticated, cable tray anchored to the substation equipment supports and/or above-grade trestles should be considered. The tray could be selected to provide circuit segregation. Grounding of non-current-carrying metal parts such as exposed cable tray is necessary and is covered in Chapter 9.

In the simplest temporary substation, plastic conduit would require the least labor time. Under some conditions, the conduit could be installed on top of the site stone.

10.11 RACEWAY MATERIALS

10.11.1   Plastic

Plastic conduit, as currently available, covers an extensive list of organic materials with a variety of wall thicknesses, degrees of flexibility, available lengths, diameters, and applications.

For duct types, characteristics, and applications, see the appropriate NEMA standard or manufacturers' data. This information should include the codes and standards met by the listed conduit types.

10.11.2   Fiber

Fiber conduit is a smooth-bore duct made of wood pulp pressure felted on a rotating mandrel, dried, and vacuum impregnated with hard coal tar pitch. The ends of 8-foot lengths are tapered, as are couplings. Cutting can be done with a coarse-tooth hand saw, and a factory-quality taper is easily accomplished with a tapering tool.

The material is manufactured with wall thickness for direct burial or concrete encasement. Angle couplings, bends, and offsets are available. Adapters for joining to threaded steel, reducers, and caps are stock items with many distributors.

Manufacturers' data and detailed installation instructions are easily obtained.

10.12 RACEWAY SIZING

Raceway sizing is an important parameter in substation design, particularly for a large installation. When laying out the underground system, it is important to visualize the station as it will be as expanded, possibly to the ultimate configuration.

In sizing individual conduits of the system, good practice indicates 40 percent maximum fill for each conduit. This means the total cross-sectional area (over insulation) of all conductors in a conduit should

not exceed 40 percent of the cross-sectional area of the interior of the conduit or duct. As an example, a 4-inch conduit has an internal area of 12.72 square inches; hence, at 40 percent fill, the total conductor area should not exceed 5.09 square inches. This practice is allowed by the *NEC* and refers to single ducts.

In the planning stages, the ultimate substation has to be visualized and duct banks sized to provide for all required cables, remembering that all substation control cables originate at the control house. Duct exits should be provided for ultimate requirements.

It was previously noted that underground duct bank application is decreasing in substation expansion and new substation design, giving way to cable trenches. When the uncertainties of below-grade duct bank design for a future expansion program are considered, cable trench becomes a viable alternative.

The *NEC* outlines the sizing of cable tray. The same article can be used as a guide for cable trench sizing. The limits in the article can be exceeded within reason because the trench will be located outdoors with normally lower ambient temperatures than for indoor tray.

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RUS Bulletin 1753F-208, "RUS Specification for Filled Telephone Cables with Expanded Insulation (PE-89)."

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RUS Bulletin 50-70, "RUS Specification for 15 kV and 25 kV Primary Underground Power Cable"

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UL Std. 44, "Rubber-Insulated Wires and Cables."

UL Std. 83, "Thermoplastic-Insulated Wires and Cables."

UL Std. 854, "Service Entrance Cables."

UL Std. 1072, "Medium-Voltage Power Cables."

UL Std. 1277, "Electric Power and Control Tray Cables with Optional Optical-Fiber Members."

CHAPTER 11
CORROSION

11.1   GENERAL

Corrosion is the deterioration of a metal by chemical or electrochemical reaction with its environment. The basic reason for corrosion problems in and around the substation grounding grid is electrochemical in nature.

11.1.1   Characteristics of Corrosion

The way in which corrosion affects underground structures varies depending on the mechanism and circumstances. In general, there are two types of corrosion. One is the general metal loss in which the entire surface of the metal exposed to the soil in a given area is corroded away. Typical of this is the general thinning of strands on a concentric neutral cable throughout the area. The second type of corrosion is localized or "pitting"-type corrosion. In this form, very local areas of metal are attacked while the metal immediately adjacent remains untouched. This type of corrosion can also be found on concentric neutral cables. It generally results in the breakage of many of the individual strands of the neutral, rendering it disconnected and either useless or significantly reduced.

The important difference between local pitting corrosion and general metal loss is that it takes very little metal loss of the local pitting type of corrosion to cause a complete loss of continuity in a neutral wire or to penetrate a pipe wall or lead sheath. Therefore, local pitting-type corrosion is more serious to the power industry.

The substation grounding grid corrosion is caused by an electrochemical reaction in the soil environment called a "galvanic cell" or sometimes a "corrosion cell." The galvanic cell is made up of three parts: the anode, the cathode, and the electrolyte.

The environment that we are talking about (soil, in this example) is called the electrolyte. The electrolyte is defined as an ionic conductor. In other words, it transfers or allows the transfer of ions.

The electrode at which chemical reduction occurs is called the cathode (positive current enters the cathode from the electrolyte). The electrode at which chemical oxidation (corrosion) occurs is called the anode (positive current leaves the anode and enters the electrolyte).

It is necessary for the anode and the cathode to be connected together electrically to complete the corrosion cell. For a corrosion cell to function, there has to be an electrical potential between the anode and the cathode.

This electrical potential can result from a number of conditions. Two of the most common corrosion cells encountered result from:

1.   Dissimilar metals in the same environment
2.   The same metal in dissimilar environments

11.1.2   Dissimilar Metals

When two dissimilar metals are placed in the same environment, there will be a difference in dc voltage

because of the different activity levels that the metals occupy in the Electromotive Force (EMF) Series. In a typical substation, a voltage difference on the order of 1 volt will probably exist between a copper ground cable and galvanized steel structures, and a dc corrosion current will flow from the steel. The current will be limited by the resistance between the structures in accordance with Ohm's law and also by surface films, which may greatly reduce the current and the rate of corrosion. Another example of dissimilar metal corrosion would be an underground bare copper cable and a galvanized conduit buried in the ground inside a substation.

There are other examples of dissimilar metal corrosion.

11.1.2.1   Old Steel vs. New Steel: When old steel is connected to new steel, the old steel actually acts as the cathode and the new steel acts as the anode. See Figure 11-1.

NEW STEEL PIPE   OLD STEEL PIPE

+
CONVENTIONAL CURRENT FLOW
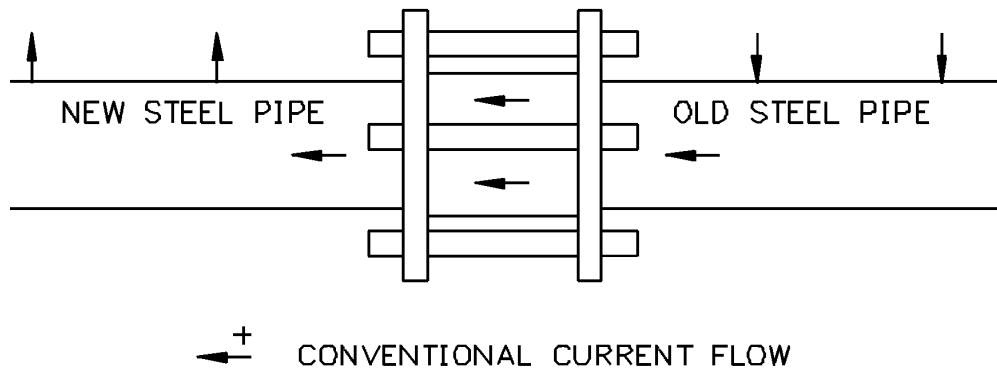
Figure 11-1: Dissimilar Metal Corrosion—Old Steel vs. New Steel

11.1.2.2   Stress Corrosion: Areas of metal that are under stress (i.e., straight pipe that is bent for construction purposes) tend to be anodic compared to areas that are not under stress.

11.1.3   Dissimilar Environments

Differences in dc potential along the ground grid conductors or concentric neutrals can be caused by varying oxygen concentrations, different values of pH, or because the soil resistivity varies over a fairly wide range. In this case, areas effected by corrosion may be at random locations that would have to be located.

There are other examples of dissimilar environment corrosion.

11.1.3.1   Oxygen vs. No Oxygen: One element that is very important in its effect on underground corrosion is oxygen. Either through its presence or its absence, oxygen is one of the primary causes of metal deterioration underground. As a result of soil compaction during backfill, the type of soil, or the steel conduit being laid in the bottom of the trench, steel conduits often have less oxygen near the bottom of the pipe. See Figure 11-2.

11.1.3.2   Different Types of Soil from Location to Location: Depending on the type of soil (sandy, clay, loam, etc.), the pipe may vary from anodic to cathodic. This generally does not occur in smaller substations, but should be a consideration in larger substations. See Figure 11-3.
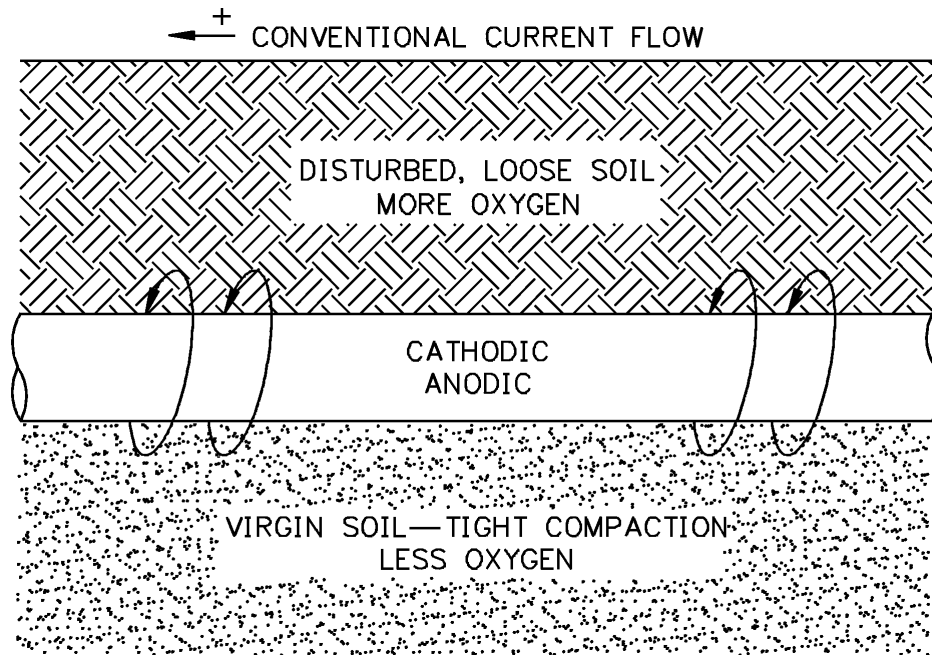
Figure 11-2: Dissimilar Environment Corrosion—More Oxygen vs. Less Oxygen
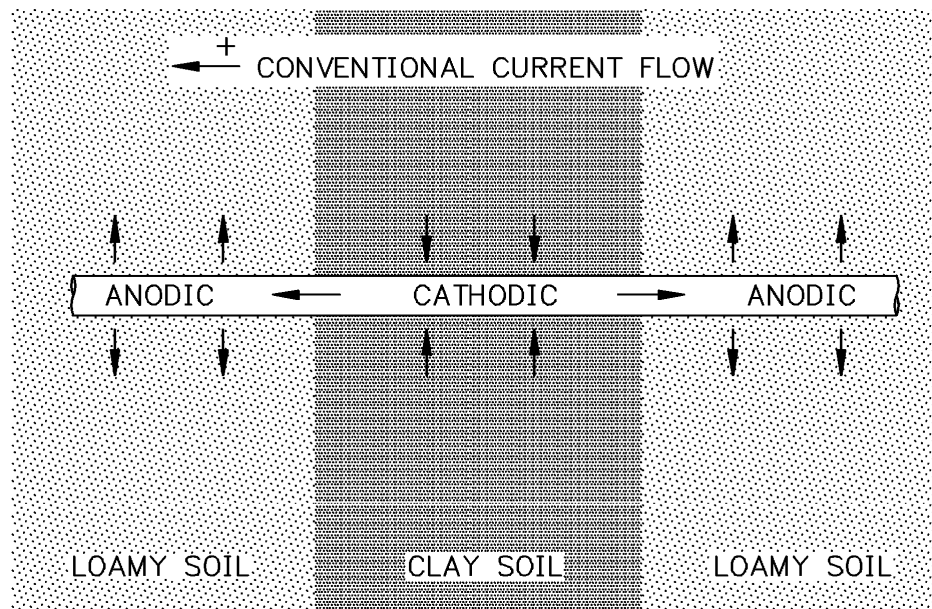
Figure 11-3: Dissimilar Environment Corrosion—Different Soil Types

For a more detailed treatment of basic corrosion theory, see the References in Section 11.4.

11.2 PRELIMINARY PREVENTIVE MEASURES

11.2.1 Surveys

It is important that certain preliminary data be obtained prior to final site selection so that corrosion

problems can be avoided or minimized. This procedure ensures that design and/or material selection will minimize possible corrosion problems. The preliminary data should include the following items.

11.2.1.1   Soil Resistivity Survey: A soil resistivity survey at each proposed site is the necessary first step, since the economic choices of materials and designs will vary with soil resistivity. Once soil resistivities are known, decisions can be made regarding overhead or underground feeder construction, the use of jacketed cable, and anodes or other cathodic protection against corrosion.

For soils of high resistivity (over 200 ohm-meter) where both grounding and cathodic protection are difficult to accomplish, semiconducting jacketed cable may be the most effective.

One way to obtain this information would be using the four-pin method. See Section 9.3 of this bulletin for further information on soil resistivity.

11.2.1.2   pH Survey: A pH survey of each substation site should also be a part of any corrosion evaluation. Soils seldom have a pH lower than 5 (acid) or greater than 8 (alkaline), where 7.0 is neutral. Soils with a pH of 5 and lower can contribute to severe corrosion and rapid deterioration of exposed metals. Acid soil conditions are usually limited to soils containing decomposed acidic plants and needles from coniferous trees. Soils with a pH of 8 and above can contain a high concentration of dissolved salts resulting in a low soil resistivity. Soils of this type are referred to as alkaline or calcareous. Alkaline soils are high in sodium and potassium, while calcareous soils are high in magnesium and calcium. Alkaline earth elements such as magnesium and calcium tend to form protective layers on ferrous metal surfaces and are considered favorable environments for metals.

11.2.2   Selection of Materials

Select materials to minimize dissimilar-metal corrosion effects due to buried copper and steel (or other metals) in the same environment. For example, the grounding system at any one substation location should consist wholly either of copper or steel. This is particularly important in corrosive soils such as those with low values of earth resistivity (less than 20 to 30 ohm-meter). No commonly used material can be wholly immune to possible corrosion damage. However, in the absence of a planned maintenance program to periodically determine the specific condition of ground grid conductors, the final choice of material should consider the available, proven historical records of the materials under consideration.

Where buried steel such as steel anchor assemblies, piping, and conduit is of necessity connected to the copper grounding grid for safety, the higher the ratio of steel-to-copper surface area, the less likely will be the adverse effects of corrosion of the steel. Where the copper grounding system is the only metal placed in the substation soil, be alert for possible interconnected steel in nearby line anchor assemblies, piping, wells, conduit, or oil or gas lines that may be inadvertently connected to the grounding system and subject to accelerated corrosion. If such conditions exist, cathodic protection of the interconnected steel may be necessary. For large substations, a rectifier-type cathodic protection scheme may be required.

11.3   TESTING AND INSTALLATION

11.3.1   <u>Earth Resistivity Measurements</u>

Earth resistivity in undisturbed soil may be determined typically with a four-terminal ground tester and test electrodes. Avoid test locations close to parts of an existing ground mat or other buried metal. See Section 9.3 of this bulletin for a full description of testing and analyzing resistivity.

11.3.2   <u>Soil Samples</u>

Obtain soil samples at the approximate depth of the underground structures in the substation. These samples can usually be obtained with a soil auger. A pH reading can be taken immediately, or the soil can be stored in an airtight container such as a plastic bag and the readings taken at a later time. Lower pH values generally indicate more corrosive soils. These tests can be handled by a testing laboratory or done in house using commercially available soil testing kits.

11.3.3   <u>Anode Locations</u>

Sacrificial anodes, where used, should be placed:

1.   At locations of the lowest resistivity soil within or near the substation area

2.   At depths at least equal to those of the ground grid and/or other assemblies to be protected

3.   Three to six meters away from the buried bare conductors or other assemblies, to the extent that space allows

Usual anode locations are at edges or corners of the ground grid, and at structures in low-resistivity locations near the substation. The connection from anode to the system neutral and station grid should be reliable and have low resistance. Compression fittings or exothermic welded connections are preferable to bolted connections or clamps.

11.3.4   <u>Underground Connections</u>

Exothermic welding is preferred to clamps or bolted connections for dissimilar-metal (copper-to-steel) connections underground. For similar metal, copper-to-copper or steel-to-steel (galvanized) connections, suitable bolted or clamped connections with clamps of the same material should be satisfactory. Cover welds with mastic or other underground coating (such as used for pipelines) in very corrosive soils with resistivities in the range below 10 ohm-m. In most soils this is not considered necessary.

11.3.5   <u>Estimating Corrosion Conditions from DC Potential Measurements</u>

One frequently used indicator of corrosion or freedom from corrosion is the dc potential (voltage) measured from a copper–copper sulfate reference electrode or half-cell. This measurement is made as shown in Figure 11-4.

The copper–copper sulfate half-cell is a copper rod surrounded by a saturated solution of copper sulfate (blue vitriol) in water, with a porous plug to allow the solution to come in contact with the soil. The voltmeter usually is a potentiometer (null-type) voltmeter or a special high-resistance (10 megohms or
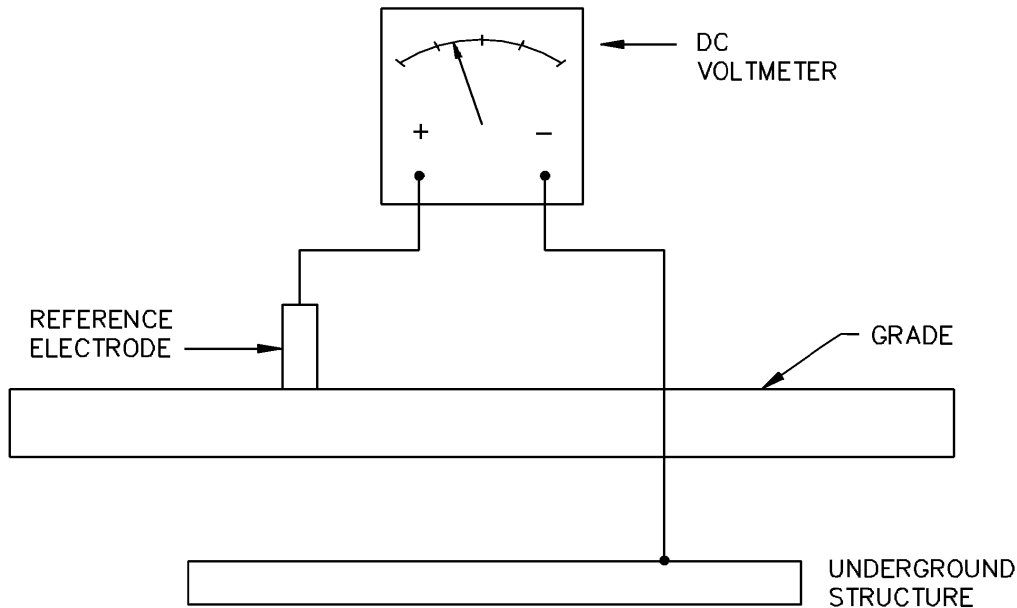
CONNECTIONS FOR MEASURING POTENTIAL OF AN UNDERGROUND STRUCTURE

Figure 11-4: DC Potential Measurement for Indication of Corrosion Conditions

higher) low-range voltmeter. However, a useful reading may also be possible with a 20,000 ohm-per-volt dc meter with a 2.5-volt range. See Figure 11-5.

The variations in dc potential are small and often expressed in millivolts. Usually, the neutral is negative with respect to the copper–copper sulfate half-cell. Table 11-1 lists some typical potentials for metals and combinations of metals that may be present and connected to a substation ground grid.

Table 11-1: DC Potentials of Various Buried Metals.
Based on Hagan, "Basic Electrical and Corrosion
Fundamentals Involved in Pipeline Corrosion."

Buried Metal	Typical Potential Volts
Zinc or new galvanized steel	−1.1 or more negative
Steel fully protected against corrosion	−0.85 or more negative
Old buried steel pipe	−0.65
"Copper-grounded" neutral with anchors and steel piping connected	−0.50 to −0.65
All-copper grounded neutral	−0.30

DC potential measurements indicate the effectiveness of anodes for cathodic protection. For example, anodes may be installed at a copper-grounded substation to relieve corrosion of anchor rods near the substation. If the anodes are effective, the station ground grid becomes more negative. The potential might be shifted from −0.55 volt to −0.75 volt. In a situation where original anchor rods have begun to fail after 15 years, such a change in potential should be adequate to ensure permanence of the newly installed anchors. In very corrosive soils (such that anchor rods might otherwise fail in five years or less), a shift to at least −0.85 volt may be needed for complete protection.

REMOVABLE CAP

TEST LEAD TO
VOLTMETER (+) TERMINAL

COPPER ROD

SATURATED SOLUTION OF
COPPER SULFATE IN
DISTILLED WATER

TRANSPARENT
PLASTIC TUBE

COPPER SULFATE CRYSTALS
TO MAINTAIN SATURATED
SOLUTION

POROUS CERAMIC PLUG
CONTACTING SURFACE
OF EARTH

GRADE
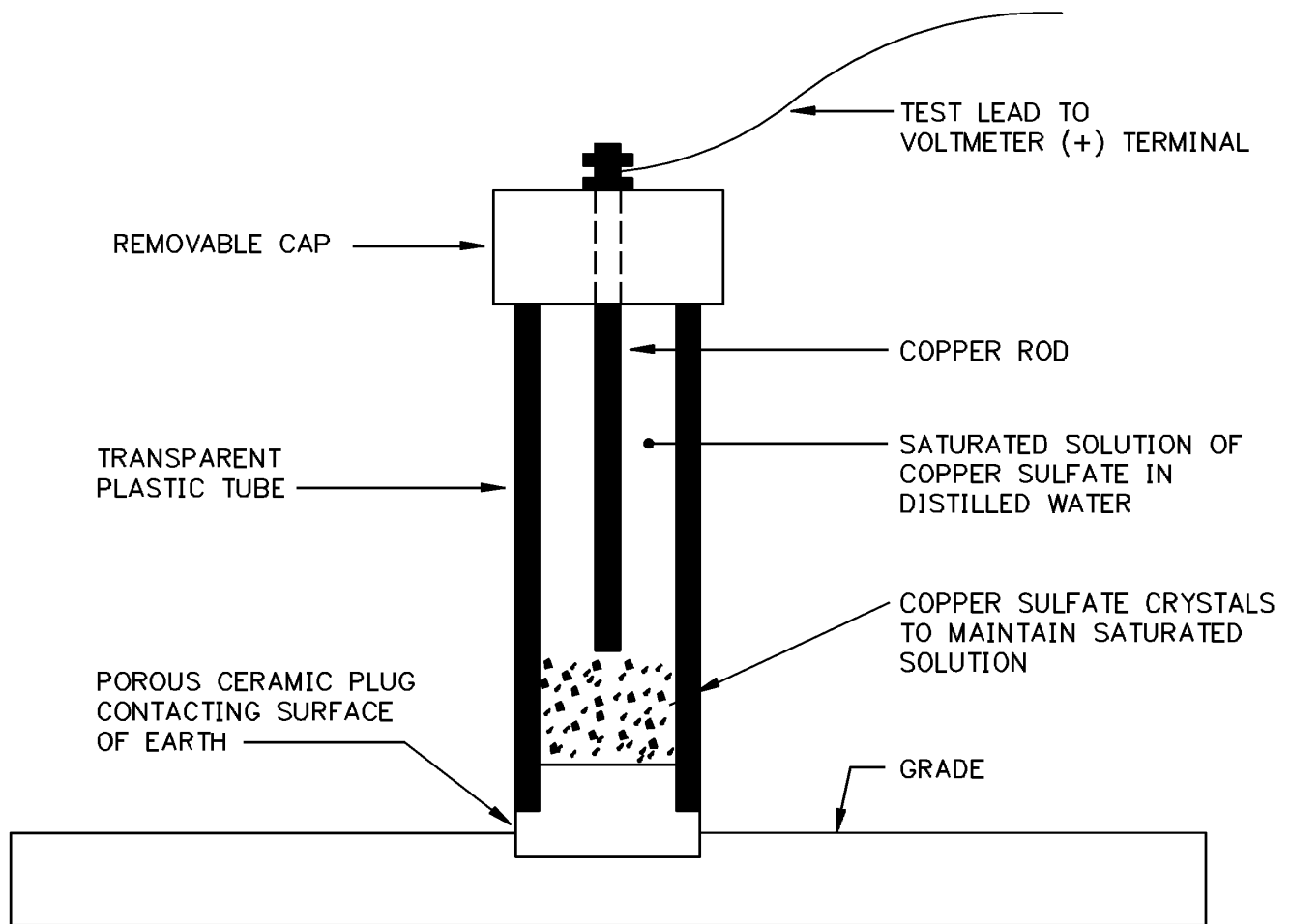
Figure 11-5: Copper–Copper Sulfate Half-Cell

Very little is known about potentials of copper corroding in soil. However, copper corrosion has been observed in a neutral to moderately alkaline soil (pH 7.1 to 8.0) at potentials of –0.10 to +0.047 volt with reference to a copper–copper sulfate half-cell. For the present, if cathodic protection of copper is found to be necessary, a potential of –0.35 volt is suggested for purposes of design.

In distribution substations, underground exit feeders with bare concentric neutrals may be vulnerable to corrosion. They should be provided with cathodic protection if the possibility of corrosion is believed to exist.

In addition to dc potentials, the measurements in Table 11-2 have significance in underground corrosion surveys.

Earth resistivity measurements help to indicate the degree of corrosiveness of the soil. Low resistivity soils (lower than 15 to 20 ohm-m) are regarded as relatively corrosive to steel or copper. High resistivity,

well-aerated soils such as sand and gravel may also be corrosive to copper. Locations of sudden change in earth resistivity, including roadside ditches where salt accumulates, are probable locations of corrosion.

Table 11-2: Soil Corrosiveness vs. Resistivity

Severely Corrosive	0-5 ohm-m
Very Corrosive	5-10 ohm-m
Corrosive	10-30 ohm-m
Moderately Corrosive	30-100 ohm-m
Slightly Corrosive	100-250 ohm-m
Less Corrosive	Above 250 ohm-m

Guy current measurements, at cable terminal poles and other guyed poles nearby, indicate locations of anchor rod corrosion and probable corrosion of other buried steel in the vicinity. See Figure 11-6.
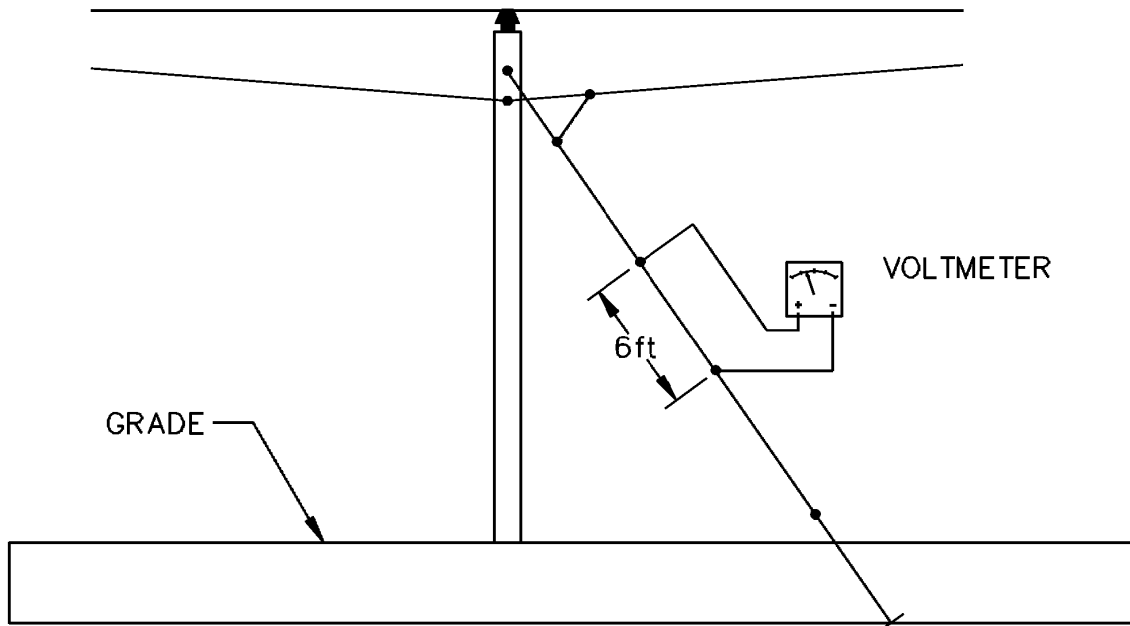
Figure 11-6: Voltage Drop Measurement to Determine Direct Current Flow

Neutral-to-earth resistance measurements indicate the overall effectiveness of grounding. Multi-grounded electric distribution neutrals normally have a low resistance to earth. See Figure 11-7.

11.4   REFERENCES

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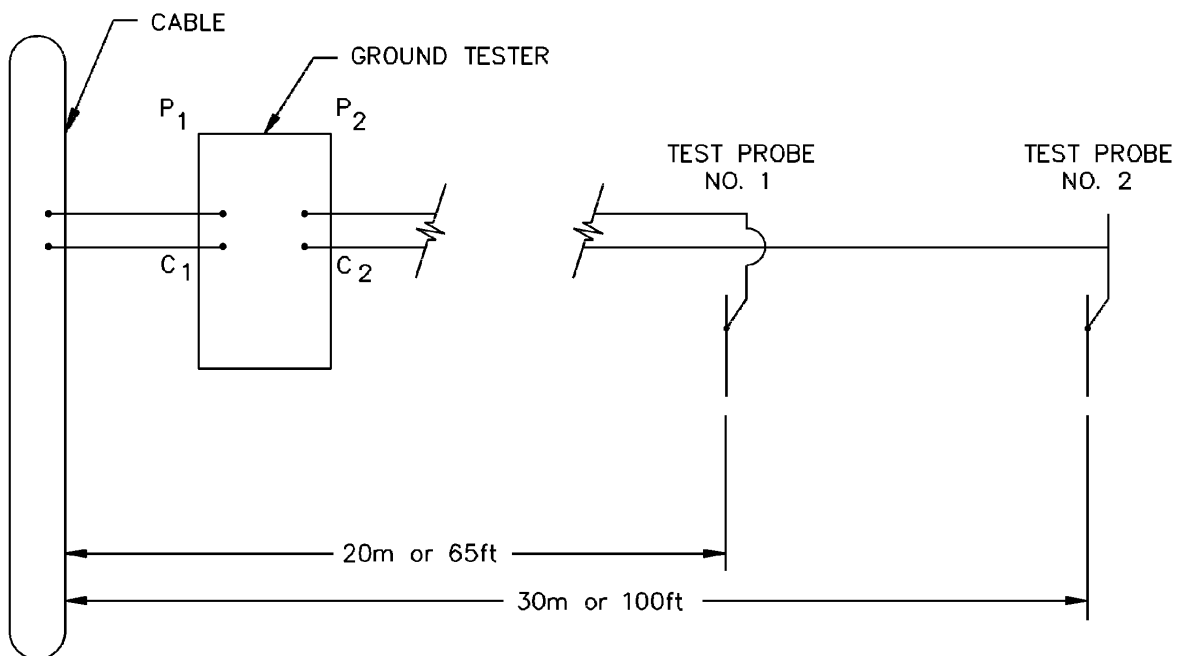
Figure 11-7: Neutral-to-Earth Resistance Measurements

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CHAPTER 12
PROTECTIVE RELAYING

12.1 GENERAL

12.1.1 Purpose of Protective Relays

Protective relays are used to detect defective lines or apparatus and to initiate the operation of circuit-interrupting devices to isolate the defective equipment. Relays are also used to detect abnormal or undesirable operating conditions other than those caused by defective equipment and either operate an alarm or initiate operation of circuit-interrupting devices. Protective relays protect the electrical system by causing the defective apparatus or lines to be disconnected to minimize damage and maintain service continuity to the rest of the system.

12.1.2 Design Objectives

The design objectives of a protective relaying are to minimize the effects of a system disturbance and to minimize the possible damage to power system equipment. A good protective relaying system will address dependability, security, speed, and simplicity.

12.1.2.1 Dependability: Dependability is the certainty of correct operation in response to system troubles. Dependability includes the reliable operation of the relay system operating when it is supposed to and selectivity of the relay system operating to isolate the minimum amount of the system necessary to provide continuity of service.

12.1.2.2 Security: Security is the ability to avoid misoperations between faults. Every relay system has to be designed to either operate or not operate selectively with other systems.

12.1.2.3 Speed: Speed means clearing all faults in the shortest possible time with all due regard to dependability and security.

12.1.2.4 Simplicity: A relaying system should be no more complex than is required for any given application. Adding more equipment into a scheme than is necessary for good coverage adds to the possibility of equipment failure and misoperation.

12.1.3 Indications of Defective Equipment or Abnormal Conditions

12.1.3.1 Short Circuits: A short circuit is an abnormal connection of relatively low resistance between two or more points of differing potential in a circuit. If one of these points is at ground potential, it is referred to as a "ground fault." If ground potential is not involved, it is referred to as a "phase fault." Phase faults cause excessive currents and low voltages. Ground faults may or may not cause excessive currents or abnormal voltages, depending on whether the system is normally ungrounded, high- or low-resistance grounded, or effectively grounded.

12.1.3.2 Excessive Heating: Equipment is designed to deliver full-rated capacity with the temperature maintained below a value that will not be damaging to the equipment. If operating temperature becomes excessive, the life of the equipment (generator, motor, transformer, etc.,) will be

reduced. Excessive heating may be caused by overloading, high ambient temperatures, improper cooling, or failure of cooling equipment.

12.1.3.3   Overvoltage: Equipment is designed for normal operating voltages as stated on its nameplate with a slight allowance (usually about 5 percent) for normal overvoltage. Abnormal overvoltage may cause:

1. Insulation failure
2. Shortening of the equipment life
3. Excessive heating as a result of greatly increased excitation currents where electromagnetic devices are used
4. Excessive heating in resistors used in controls
5. Failure of transistors and other electronic devices

12.1.3.4   Undervoltage: Continued undervoltage will likely cause overheating of motors and dropping out of contactors, and lead to the failure of electrical equipment.

12.1.3.5   Unbalanced Phase Conditions: On balanced three-phase systems with balanced three-phase loads, a sudden unbalance in the current or the voltages usually indicates an open or a partially shorted phase. An unbalanced voltage condition is especially serious for three-phase motors because negative sequence currents can lead to considerable overheating within the motor. On balanced three-phase systems with single-phase loads, the loading on each phase may normally vary, depending on the magnitude of each single-phase load. However, it is desirable to keep this unbalance to a minimum to maintain balanced voltages for three-phase loads. Unbalanced conditions, which include single-phase and double-phase faults with or without ground, can be detected with the use of negative and zero sequence relay elements.

12.1.3.6   Reversed Phase Rotation: Reversed phase rotation can occur after circuit changes have been made or during an open phase condition. Reversed rotation of motors may cause considerable damage to the facility driven by the motors, such as a conveyor.

12.1.3.7   Abnormal Frequency: Abnormal frequencies can occur when the load does not equal the generation. The frequency may be above or below the system normal frequency. Many facilities such as electric clocks, synchronous motors, etc., are frequency sensitive.

12.1.3.8   Overspeed: Considerable mechanical damage can be done to generators and motors because of overspeed. Excessive overspeed may cause parts of the generator or motor to be thrown for considerable distances, which is dangerous to personnel as well as to other facilities. Generators or series-connected motors may reach dangerous overspeeds when loads are suddenly removed.

12.1.3.9   Abnormal Pressure: In electrical equipment, such as transformers, that use liquid as an insulating fluid, high internal pressures can be created during internal faults.

12.1.3.10   Abnormal Impedance: Electrical equipment has impedance associated with it that either has definite known values or values that may vary within a known range during known varying operating conditions. These values are normally determined during the manufacture and installation of equipment. Substantial deviations in the impedance of the equipment can indicate a failure of the equipment.

12.1.3.11 **Out-of-Step Conditions :** Electric power systems in North America operate at a frequency of 60 hertz . All the generators and rotating equipment on the system rotate at an rpm to maintain the 60 hertz frequency. As such, each machine on the electrical system maintains a relative position, or phase angle, with respect to every other machine on the system. Once a machine exceeds a critical phase angle, it can no longer stay in phase with the system. It is said to have moved out of step with the system, and has to be removed from the system and resynchronized to the system in order to establish operation. Out-of-step conditions are typically monitored through the use of impedance relays and set to trip or block the trip of breakers in order to segment the system at predetermined locations based on system stability studies.

12.1.3.12 **Excessive System Phase Angles (Synchronism Check):** The closing of a circuit breaker on a system connects the electrical systems on either side of the circuit breaker. The closing of the breaker will cause any difference of voltage and phase angle across the breaker to be reduced to zero, causing current flow from one system to the other to equalize the system voltages, currents, and phase angles. If the voltage and phase angle differences across the breaker are too much, excessive currents can flow, resulting in a disturbance to the system, possibly damaging the breaker or adjacent rotating equipment. Typically, the voltage and phase angle across the breaker are compared to confirm the systems are within proper limits before the breaker is closed.

12.2   FUNDAMENTAL CONSIDERATIONS

12.2.1   Phasors

A phasor is a complex number used to represent electrical quantities. In protective relaying systems, phasors are used to aid in applying and connecting relays and for analysis of relay operations after faults. Phasor diagrams have to be accompanied by a circuit diagram. The phasor diagram shows the magnitude and relative phase angle of the currents and voltages, while the circuit diagram shows the location, direction, and polarity of the currents and voltages.

12.2.2   Polarity

The relative polarities of a current transformer's primary and secondary terminals are identified either by painted polarity marks or by the symbols "H1" and "H2" for the primary terminals and "X1" and "X2" for the secondary terminals. The convention is that, when primary current enters the H1 terminal, secondary current leaves the X1 terminals. Or, when current enters the H2 terminal, it leaves the X2 terminal. When paint is used, the terminals corresponding to H1 and X1 are identified. Since ac current is continually reversing its direction, one might well ask what the significance of polarity marking is. Its significance is in showing the direction of current flow relative to another current or to a voltage, as well as to aid in making proper connections. The polarity marks for a potential transformer have the same significance as for a current transformer.

12.2.3   Faults

A system fault (short circuit) is a condition in which the electric current follows an abnormal path as a result of the failure or removal of the insulation that normally confines the electric current to the conductors. Insulation is usually either air or high-resistive material that may also be used as a mechanical support. Air insulation can be accidentally short-circuited by birds, rodents, snakes, kite strings, tree limbs, etc.; broken down by overvoltage due to lightning; or weakened by ionization due to a fire or smoke. Organic insulation can deteriorate because of heat or aging or can be broken down by

overvoltage due to lightning, switching surges, or faults at other locations. Porcelain insulators can be bridged by moisture with dirt or salt, or can develop a crack as a result of mechanical forces.

12.2.4   Symmetrical Components

Symmetrical components are the foundation for obtaining and understanding fault data on three-phase power systems. Formulated by Dr. C.L. Fortescue in a classic AIEE paper in 1918, the symmetrical components method was given its first application to system fault analysis by C.F. Wagner and R.D. Evans in the late 1920s and early 1930s. W.A. Lewis added valuable simplification in 1933. Today, fault studies are commonly made with a digital computer. System changes can be accurately modeled and incorporated into the database. Knowledge of symmetrical components is important both in making a study and in understanding the data obtained from the computer. It is also extremely valuable in analyzing faults and relay operations. A number of protective relays are based on symmetrical components. Symmetrical components are one of the most powerful technical tools used by a relay engineer. The practical value lies in the ability to think and visualize in symmetrical components.

Several good courses on symmetrical components are available from manufacturers. The relay engineer should become well acquainted with the use of symmetrical components since it is a primary means of communicating about and analyzing system faults.

12.2.5   Relay Input Sources

Instrument transformers provide relays with currents and voltages that are proportional to voltage and currents flowing in the primary circuit. Voltage signals are obtained from potential transformers (PTs) and current signals from current transformers (CTs). Instrument transformers and their applications are described in Section 5.10.

12.3   BASIC RELAY TYPES

12.3.1   General

Protective relays consist of three basic modules:

1.   An input module
2.   A decision module
3.   An output module

See Figure 12-1. The modules are each constructed of components that will vary depending on the type of construction of the relay: electromechanical, static, or microprocessor.

Figure 12-1: Logical Representation of Protective Relays

Relays are also classified according to the function they provide to the system. The five most common functions are:

1. Protection
2. Regulation
3. Reclosing and synchronization
4. Monitoring
5. Auxiliary

The primary emphasis of this discussion is protection. Other functions are included as applicable.

Each of the basic relay modules operates to perform tasks as follows.

12.3.1.1   Input Module: The principal input module task is to receive the inputs from the electrical system to the relay, generally in the form of currents, voltages, and status input contacts. It acts as the interface between the relay decision module and the electric power system, protecting the sensitive decision module from the harsh environment of the electric power system. The electrical system input section typically consists of transformers, transactors, zener diodes, electronics, and other equipment to provide a signal, proportional to the inputs, to the decision module. The input equipment will condition the input signals to be in a format required by the decision module. Conditioning may include converting the voltage, contact, or current inputs into voltages or currents suitable to electronic equipment. Conditioning may also include the conversion of the signals from analog values to digital values. The input section also will typically contain equipment that will provide protection for the relay to withstand the surges, transients, and oscillations that may be present in the substation environment.

An additional task of the input section of the relay is to provide for the input and storage of the relay settings. For electromechanical and static relays, this is most often the setting of various taps, dials (which will normally preset tension on a spring), and selector switches on the face of the relay. For microprocessor relays, the input section often includes a series of push buttons that will allow the input of relay settings or the input of requests for the relay to display settings or data processed by the relay. The relay settings will be stored for use by the relay in providing its protective functions.

Microprocessor relays often include a number of additional inputs to the relay. Included in these inputs are the power supply; clock signals to provide sequence of events (SOE) timing; communication ports to provide direct computer, SCADA, or other data inputs; and front panel push buttons to set the relay or scroll through the metering functions. Microprocessor relays are often provided with multiple relay setting groups that will allow for changes in the electric power system configuration. The change from one settings group to another can usually be keyed locally by an external contact in the substation control scheme or remotely via SCADA. It should be noted that there is an inherent danger of inadvertently changing a relay setting or setting group with this type of microprocessor relay.

The relay engineer has to be aware of the electrical system inputs that are available for use in determining the failure of the electric power system or electric power system components. Knowledge of the electric power system and how the system responds to various failures is invaluable in making decisions as to the types of relays that are used to protect the electric power system.

12.3.1.2   Decision Module: This module monitors the input data included in the relay settings input to the relay and the system data, including currents, voltages, status contacts, and control signals that were input to the relay. The module will evaluate the system data in comparison to the relay settings. When the system data exceed the threshold determined by the relay settings, this module will signal the output module to function and record the results. The quantities to which the relay responds usually designate the relay type.

For electromechanical relays, the decision module often consists of disks that work by induction, plungers, or solenoids; levers that will work on a balance beam principle; units that work on the basis of thermal characteristics; or D'Arsonval units that consist of a combination of fixed magnetic and electromagnetic elements. Each of the units is configured with a contact that either makes (closes) or breaks (opens) upon the operation of the device. The recording of the action is usually accomplished by the dropping of a target to indicate the relay operation. The module compares the input relay settings to the input signals through the inherent magnetic or thermal action of the relay to overcome the spring tensions and inertia associated with the relay settings. Relays may operate (1) instantaneously, (2) with some definite time delay, or (3) with a time delay that varies with the magnitude of the quantities to which the detecting element responds.

Static relays replace the electromechanical components with solid-state components and make the comparisons by electronic means. Static or solid-state detecting elements generally convert the current, voltage, or power inputs to proportional dc millivolt signals that are then applied to adjustable transistor amplifiers. These amplifiers have a "go–no go" characteristic that causes an input signal up to the set level to produce no output and input signals beyond that level to produce full output. The output may be another dc millivolt signal applied to further transistor logic or to a contact closure. Indication of the operation of the relay is usually accomplished by the dropping of a target to indicate the relay operation.

Microprocessor relays replace the decision module with a small digital computing unit that utilizes sampled input data and digitized setting parameters. Comparisons are made digitally by the computer performing a calculation or series of calculations, comparing the relay setting information to the periodic samples obtained from the electric power system. When the threshold values are exceeded, the module activates the output module. Most relays will also store a number of metering values, the status of input devices, intermediate logic elements, and other information available to the relay in output storage registers. The information is then available for retrieval by the engineer at his convenience, either locally at the substation or remotely through communications that are often provided to the relay.

Microprocessor relays usually include internal self-checking functions for the majority of their functions. Should a failure occur within the logic of the relay, an alarm will be given to the relay output module that the relay is in an alarm condition. The relay engineer also needs to be aware of the functions and features that may not be covered by an alarm, such as the capability of the output relays to function.

12.3.1.3   Output Module: This module provides an output from the decision module to the control system in order to operate electric power system equipment and isolate faulty system components.

For electromechanical relays, this system typically consists of output contacts or auxiliary relays with multiple contacts. The contacts act as the interface between the relay and the electric power control system. These contacts are then used to trip circuit breakers, provide alarms, trip other relays such as lockout relays and send signals via communications to remote equipment or personnel, or other functions. The contacts will carry specific ratings for the voltages and currents they will successfully carry or break.

Static relays provide the option for outputs to be either auxiliary reed (magnetically activated) relays and their associated contacts or solid-state-controlled thyristors. Electronically controlled thyristors are usually faster than their relay counterparts. Triggering circuitry may include opto-isolators to provide isolation between the relay and the harsh environment of the electric control system.

Microprocessor relays will use either reed relays or solid-state-controlled thyristors for output elements. Usage will vary between manufacturers and may be optional to the user. In addition to the standard relay outputs, microprocessor relays may include a number of additional output contacts that may be

programmed for the user's requirements. One of the output contacts is normally designated as the relay alarm contact. Most relays include a number of output storage registers where the relay stores a number of metering values, the status of input devices, intermediate logic elements, and other information available to the relay. The information is then available for retrieval by the engineer at his convenience, either locally at the substation or remotely through communications that are often provided to the relay. Most microprocessor relays include communication capabilities that allow the relay to transmit data in digital format to computers, SCADA systems, or local control systems.

Many microprocessor relays also include a display unit as a part of the output module. This display unit is typically used to display metering values of the inputs that are brought to the relay or metering information that is calculated in the relay. The display may also show other functions of the relay, such as the display of internal variables, flags, and input parameters. The display typically provides a means of getting information out of the relay without the requirement to connect a computer to one of the output ports.

12.3.2   Relay Selection

The type of relay selected by the relay engineer for an application is of primary importance. The engineer has to determine, with existing system knowledge or with additional studies, the types of failure that each component of the electric power system can experience and the characteristics of the failure. The electrical system inputs that will be available to the relay and the speed with which the relay has to operate to maintain electrical system stability has to be known. With this information, the engineer can apply relays that will measure the identified characteristics of the electric power system component with the previously established relay settings and operate dependably and securely in protecting the electrical system. The relay engineer should consider some of the following factors.

12.3.2.1   Electromechanical relays are the oldest and have the most history associated with them. They provide discrete protection functions within each case. Relay settings are usually straightforward and well documented in most instruction books. The relay engineer has to have a relatively good idea of the magnitudes of electrical signals that will be applied to the relay in order to obtain the proper range of settings for each application.

12.3.2.2   Static relays generally provide discrete functions similar to electromechanical relays. Since the operation of the relays depends only on threshold values being met, these relays are generally faster than their electromechanical counterparts. Static relays often come in cases similar to their electro-mechanical counterparts, making replacement relatively simple. Static relays are also available in "packages" that include all the protective functions for the line in a single rack.

12.3.2.3   Microprocessor relays often can accommodate more complex system operation because of the inputs provided to the relay and the programming features included with the relay. In many cases, numerous functions are provided in the relay so that the number of discrete relays required for protection may be reduced substantially. In many cases, additional functions may be provided to protect a system from abnormal conditions that might not otherwise be considered based on the low occurrence of such conditions or because of other considerations.

12.3.2.4   Microprocessor relays often provide the relay engineer with many more options for providing protection than either their electromechanical or static relay counterparts. Once the inputs to the relay are obtained, the decision module can then be programmed to provide many protective functions with these inputs. This information can also be used to implement the transmittal of data remotely through SCADA

or other data retrieval means. In terms of the number of functions, the microprocessor relay will often provide more protective functions for the dollar spent.

This type of relay may be slightly slower to operate than some of the electromechanical or static relays that are available. The operating speeds of microprocessor relays are typically in the range of 1.5 to 2 cycles. Some static relays may operate in less than 1 cycle.

Microprocessor relays usually include internal self-checking functions for the majority of their functions. As noted, the relay engineer also needs to be aware of the functions and features that may not be covered by an alarm, such as the capability of the output relays to function.

12.3.2.5   In new installations, the use of microprocessor relays may result in reduced cost since fewer relays are required. Generally, less floor space is needed so smaller control buildings are needed for the equipment. This may result in reduced auxiliary power system requirements. The interconnection wiring in a panel is also reduced since many of the protective functions are included in one relay enclosure.

12.3.2.6   For simple systems, control system design may be equally simple with electromechanical, static, and microprocessor relays. If the complexity of the power system requires many specific functions of protection, the microprocessor relays may provide a simpler installation.

12.3.2.7   Consider the effects of the protective relay system on the personnel who will operate and maintain the equipment. If new devices are being proposed, special training may be required for them to operate and maintain the equipment. Additional equipment may be necessary for relay testing, such as computers to connect locally to the microprocessor relays.

12.3.2.8   Consider the lifetime of the installation the relays are being applied in. Will spare parts be available for the devices? Will the manufacturer have personnel available to answer questions on the relays in the future?

12.3.2.9   Be aware that the complexity of the relay will increase the complexity of the relay settings. A simple electromechanical overcurrent relay has basically two settings: a tap setting for the pickup of the relay and the time dial to determine the time delay until trip, if any. A feeder with four overcurrent relays will thus have eight settings, with a set of common phase settings and ground settings. By comparison, a microprocessor relay may have up to 10 or more pages of relay settings. A small part of these settings will actually involve the protective functions of the relay; however, the relay engineer will need to study the applicability of the functions and determine whether or not to use them. In general, if the relay engineer does not need the function, the function should be disabled in the relay to avoid over-complicating the protection scheme.

12.3.2.10   Do not ignore the personal preferences of the cooperative regarding the protective schemes and equipment used. Design and application of protective relaying schemes is an art that uses science to make it work. In most cases, many relays and protective schemes can be used to protect a line or piece of equipment. What is used depends largely on the skill of the relay engineer and preferences of the people who will be operating and maintaining it.

12.3.2.11   Substation automation combines many functions, such as relaying, metering, and data acquisition. The relay engineer should be aware of the benefits and traps included in implementing relays in a substation automation project.

Substation automation, discussed further in Chapter 14, provides many more options for controlling equipment. There are some cases where firms use programmable logic controllers to perform protective relay functions. These cases are usually either very simple, such as providing a timing function, or very complex, providing logic to control switching or testing of a three-terminal line. In the majority of cases, the relay engineer should use relays to provide the relay functions and not introduce automation equipment into the relay functions. It is recommended the relays be used to do what they are designed to do, provide system functions, and use automation equipment to provide additional operating features or metering functions.

12.3.2.12   To communicate relaying functions being used on a system, device function numbers and contact designations have been developed to identify devices in protective relay schemes. Appendices F and G to this chapter list the function numbers and contact designations summarized from IEEE Std. C37.2, "IEEE Standard Electrical Power System Device Function Numbers and Contact Designations."

12.3.3 Overcurrent Relay

The overcurrent relay responds to a magnitude of current above a specified value. There are four basic types of construction: plunger, rotating disc, static, and microprocessor. In the plunger type, a plunger is moved by magnetic attraction when the current exceeds a specified value. In the rotating induction-disc type, which is a motor, the disc rotates by electromagnetic induction when the current exceeds a specified value. Static types convert the current to a proportional dc millivolt signal and apply it to a level detector with voltage or contact output. Such relays can be designed to have various current-versus-time operating characteristics. In a special type of rotating induction-disc relay, called the voltage restrained overcurrent relay, the magnitude of voltage restrains the operation of the disc until the magnitude of the voltage drops below a threshold value. Static overcurrent relays are equipped with multiple curve characteristics and can duplicate almost any shape of electromechanical relay curve. Microprocessor relays convert the current to a digital signal. The digital signal can then be compared to the setting values input into the relay. With the microprocessor relay, various curves or multiple time-delay settings can be input to set the relay operation. Some relays allow the user to define the curve with points or calculations to determine the output characteristics.

The protective characteristic of the overcurrent relay, in terms of the impedance diagram, is a circle, assuming a constant voltage, with the relay located at the origin of the R-X coordinate diagram (see Figure 12-2). The relay operates on the simple magnitude of current passing through it according to the settings applied to the relay.

The overcurrent relay may be the simplest relay in concept to use. When the current exceeds the setting value, it causes a trip. Complications in applying the relay may occur when the system does not provide adequate differentiation between current values, such as between short lines on a system with high fault current duties. When a number of overcurrent relays are used sequentially in a circuit, the trip delay times may become excessive.

12.3.4 Distance Relay

The distance relay responds to a combination of both voltage and current. The voltage restrains operation, and the fault current causes operation that has the overall effect of measuring impedance. The relay operates instantaneously (within a few cycles) on a 60-cycle basis for values of impedance below the set value. When time delay is required, the relay energizes a separate time-delay relay or function with the contacts or output of this time-delay relay or function performing the desired output functions.

X

R
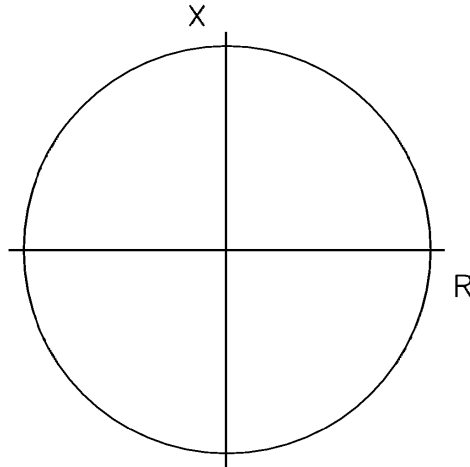
NOTE: VOLTAGE ASSUMED CONSTANT

Figure 12-2: Overcurrent Protective Characteristic

The protective characteristic of the distance relay, in terms of the impedance diagram, is a circle with the relay located at the origin of the R-X coordinate diagram (see Figure 12-3). The relay operates on the magnitude of impedance measured by the combination of restraint voltage and the operating current passing through it according to the settings applied to the relay. When the impedance is such that the impedance point is within the impedance characteristic circle, the relay will trip. The relay is inherently directional. The line impedance typically corresponds to the diameter of the circle with the reach of the relay being the diameter of the circle.

X

R
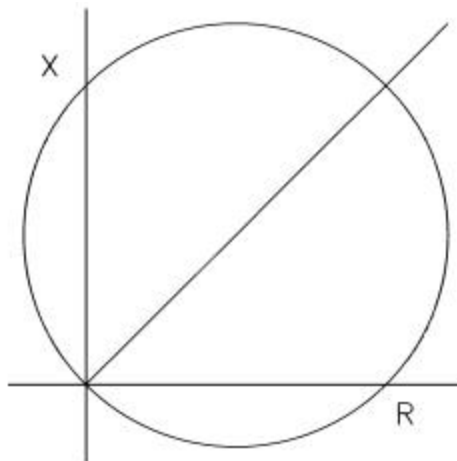
Figure 12-3: Distance Protective Characteristic

Since the relay responds directly to the value of impedance represented by the fault current and voltage applied to the relay, it will discriminate more correctly between the location of faults since the electric power system also may be represented by its impedance. The distance relay may be used more successfully on an electric power system when the magnitudes of fault current do not provide adequate location differentiation to be able to accurately trip specific breakers and isolate a fault.

The distance element in a relay may be used when a component of the electric power system, such as a transmission line, has defined impedance characteristics. Several distance elements are often used, with the circles passing through the origin of the R-X diagram, to provide several zones of protection for the system component. Additional zones of protection will be used with timers to provide direct protection, or without timers and used in pilot protection schemes requiring communications from all remote terminals of the transmission line. Distance elements may be used for out-of-step protection with the first zone impedance characteristic passing through the R-X impedance coordinate diagram origin and the remaining zones concentric around the first zone.

12.3.5 Differential Relay

The differential relay is a current-operated relay that responds to the difference between two or more currents above a set value. The relay works on the basis of the differential principle that what goes into the device has to come out (see Figure 12-4). If the current does not add to zero, the "error" (fault) current flows to cause the relay to operate and trip the protected device.
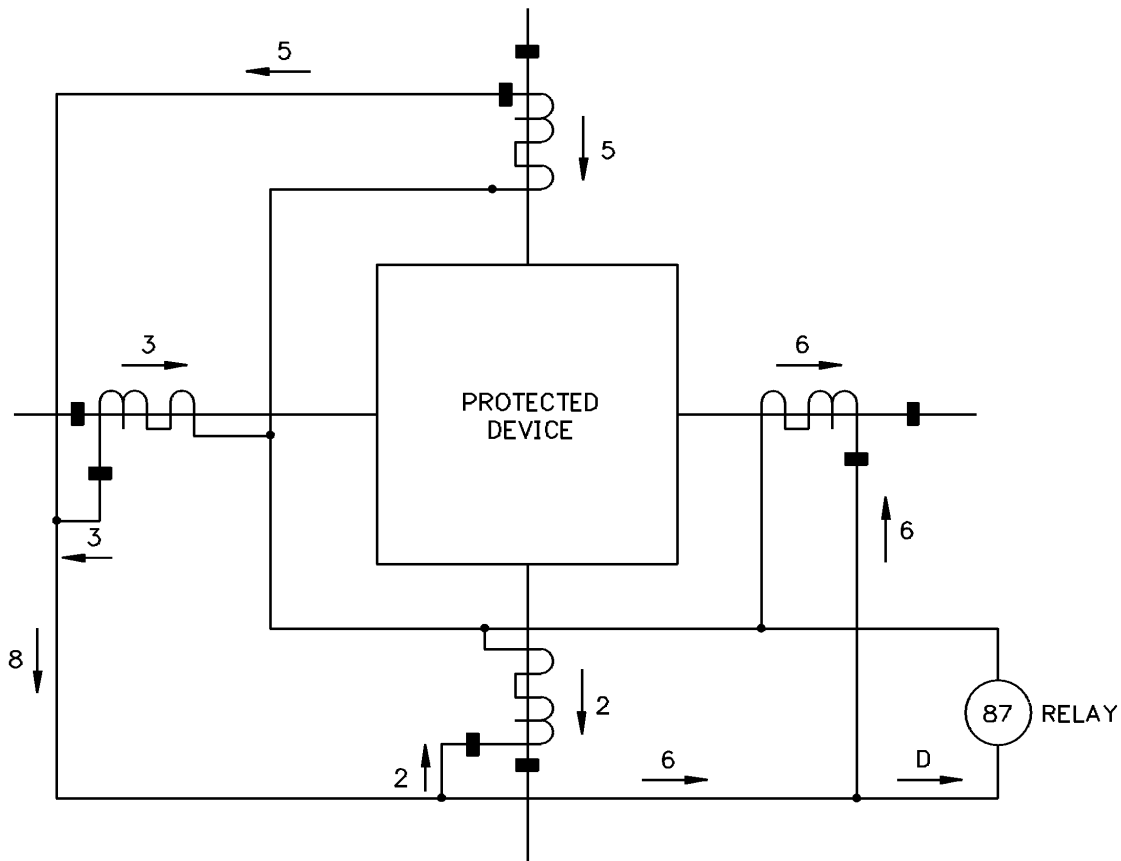
Note: For simplicity of illustration, the CTs are indicated with a 1:1 ratio
         and equal currents in the primary and secondary of the CTs.

Figure 12-4: Differential Relay Principle

The differential relay is used to provide internal fault protection to equipment such as transformers, generators, and buses. Relays are designed to permit differences in the input currents as a result of

current transformer mismatch and applications where the input currents come from different system voltages, such as transformers. A current differential relay provides restraint coils on the incoming current circuits. The restraint coils in combination with the operating coil provide an operation curve, above which the relay will operate. Some of the relays for specific equipment, such as transformers, use additional restraint proportional to the harmonics sensed in the incoming currents. Setting levels are based on the characteristics of the protected equipment.

Differential relays are often used with a lockout relay to trip all power sources to the device and prevent the device from being automatically or remotely re-energized. The relays are very sensitive. The operation of the device usually means major problems with the protected equipment and the likely failure in re-energizing the equipment.

12.3.6 Overvoltage Relay

The overvoltage relay responds to a magnitude of voltage above a specified value. As noted, the basic types of construction include plunger, rotating induction-disc, static, and microprocessor relays, all of which are discussed in Section 12.3.3.

12.3.7 Undervoltage Relay

The undervoltage relay responds to a magnitude of voltage below a specified value and has the same basic construction as the overvoltage relay.

12.3.8 Power Relay

A power relay responds to the product of the magnitude of voltage, current, and the cosine of the phase angle between the voltage and current, and is set to operate above a specified value. The basic construction includes the rotating induction-disc, static, or microprocessor relay. The relay is inherently directional since the normally open contacts close for power flow in one direction above a set value but remain open for power flow of any amount in the opposite direction.

12.3.9 Directional Overcurrent Relay

A directional overcurrent relay operates only for excessive current flow in a given direction. Directional overcurrent relays are available in electromechanical, static, and microprocessor constructions. An electromechanical overcurrent relay is made directional by adding a directional unit that prevents the overcurrent relay from operating until the directional unit has operated. The directional unit responds to the product of the magnitude of current, voltage, and the phase angle between them, or to the product of two currents and the phase angle between them. The value of this product necessary to provide operation of the directional unit is small, so that it will not limit the sensitivity of the relay (such as an overcurrent relay that it controls). In most cases, the directional element is mounted inside the same case as the relay it controls. For example, an overcurrent relay and a directional element are mounted in the same case, and the combination is called a directional overcurrent relay. Microprocessor relays often provide a choice as to the polarizing method that can be used in providing the direction of fault, such as applying residual current or voltage or negative sequence current or voltage polarizing functions to the relay.

12.3.10 Frequency Relay

A frequency relay responds to frequencies above or below a specified value. The basic types are

electromechanical relays with a vibrating reed or rotating induction-disc with a frequency-sensitive circuit, static relays, and microprocessor relays.

12.3.11 Thermal Relay

The thermal relay responds to a temperature above a specified value. There are two basic types: direct and replica.

12.3.11.1   Direct: In the direct type of thermal relay, a device such as a thermocouple is embedded in the equipment. This device converts temperature to an electrical quantity such as voltage, current, or resistance. The electrical quantity then causes a detecting element to operate.

12.3.11.2   Replica: In the replica type of thermal relay, a current proportional to the current supplied to the equipment flows through an element, such as a bimetallic strip, that has a thermal characteristic similar to the equipment. When this element is heated by the flow of current, one of the metallic strips expands more than the other, causing the bimetallic strip to bend and close a set of contacts.

12.3.12 Pressure Relay

The pressure relay responds to sudden changes of either fluid or gas pressure. It consists of a pressure-sensitive element and a bypass orifice located between the equipment to which the relay is connected and a chamber that is part of the relay. During slow pressure changes, the bypass orifice maintains the pressure in the chamber to the same value as in the equipment. During sudden pressure changes, the orifice is not capable of maintaining the pressure in the chamber at the same value as in the equipment, and the pressure-sensitive element mechanically operates a set of contacts.

12.3.13 Auxiliary Relay

Auxiliary relays perform such functions as time delay, counting, and providing additional contacts upon receiving a signal from the initiating relay. These relays are necessary to provide the broad variety of schemes required by a power system.

12.4   RELAY SCHEMES

12.4.1 General

Protective relays are most often applied with other protective and auxiliary relays as a system rather than individually. The following basic scheme descriptions apply to electromechanical, static, and microprocessor relay systems.

The static and microprocessor relay systems generally have more elaborate logic involved in the tripping decision, particularly in the area of transient blocking during external fault clearing. Static systems require more careful treatment of input circuits, i.e., CT and PT leads are often shielded. Static systems are slightly faster, require less maintenance, and are considerably more costly than the electromechanical systems.

Microprocessor relays are very versatile and often can perform many functions at a lower cost than other methods. In addition to basic relaying they may do fault locating, fault data recording, self testing, and metering. Since microprocessor relays tend to have more protective functions available in a relay case, it

often allows the relay engineer to provide additional protection the relay engineer would not have previously considered. Microprocessor relay systems tend to have fewer devices since they contain more functions in one case. This will tend to reduce the cost of initial installation.

12.4.2 Transmission Line Protection

Transmission lines provide the links between the various points of the power system and deliver power from the point of generation to the ultimate user. The lines operate at the differing voltages included in the power system. The significance of a line to the electric power system varies according to the voltage level, the location of the line in the system, the loads carried by the line, and other factors specific to the cooperative. Schemes for the relay protection of the line vary according to the significance of the line in the system, the characteristics of faults on the line, the speed at which a line fault has to be cleared, and the preferences of the relay engineer and the utility's practices. The protection schemes available for transmission line relay protection include:

1. Overcurrent, instantaneous, nondirectional
2. Overcurrent, timed with either inverse curves or discrete times, nondirectional
3. Overcurrent, instantaneous, directional
4. Overcurrent, timed with either inverse curves or discrete times, directional
5. Current differential using overcurrent
6. Distance, instantaneous and timed
7. Pilot with a communication channel between all terminals

Depending on the fault characteristics of the line in question, the relay engineer may use any of the above relay protection schemes for the protection of phase and ground faults on a transmission line. Protection schemes may include the use of the schemes individually or in combinations to protect lines with primary and secondary protection schemes.

The relay engineer has to know the following in determining the relay protection to be used for a transmission line:

1. The configuration of the transmission line
2. The number of line terminals
3. Whether the line is radial or looped in the system
4. How many taps, if any, are on the line
5. How the line will be loaded
6. Fault levels associated with the line
7. Any other transmission line-specific data peculiar to the system
8. Load-specific information such as specified outage times, temporary power levels, etc.
9. System constraints such as out-of-step relay requirements
10. Coordination requirements with relay systems of the remote line terminals

Higher voltage transmission lines tend to have more sophisticated relay protection systems often using piloted schemes (the use of communications channels providing information from the remote end of the line) to provide more security. Transmission lines at 345 kV normally utilize two primary relay schemes with pilot protection. However, the voltage of the line is not the primary factor in determining the types of relay protection that may be used. Rather, it is the significance of the line in the power system and the effect of faults on the line that will determine the speed in which the line has to be removed from the system when a fault occurs. Some lower voltage systems are in operation where extremely sophisticated

relay schemes are in place, and some 345 kV systems operate with simplistic schemes because of the characteristics of the system at the location of the line.

With the above information about the system, the relay engineer can make a decision as to the types of relay schemes that may be used. The following are schemes used for transmission line protection.

12.4.2.1   Non-Pilot Schemes: Non-piloted schemes involve the use of relays to provide protection without the use of communications channels providing information from the remote end of the line. The relay measures the input quantities, makes the action decision based on those quantities, and provides an output to the circuit breakers or circuit logic at the site of application based on the input and the relay logic. All the inputs and outputs are local to the site of application.

12.4.2.1.1   Overcurrent Relaying: Overcurrent relay protection is the simplest form of protection usually applied on lower voltage lines or on radially supplied feeders. It is used occasionally as backup relay protection for some transmission lines. In its most basic form, nondirectional inverse time overcurrent relays are applied on radial feeders with two phase devices and one ground device. The fault current is reduced by increased line impedance the further out on the line the fault occurs, resulting in a longer time for the relay to trip the feeder.

When a backfeed from another power source is possible on the feeder, directional overcurrent relays may be used to provide selectivity between faults "in front" of or in the tripping direction of the relay versus those behind the relay. An instantaneous overcurrent element is often used to protect the transmission line or feeder for high-current, close-in faults near the terminal where the relay is located.

While this type of protection can be used on a network system with varying contributions from both directions on the lines, it is extremely difficult to coordinate such a system and it should be avoided where possible.

12.4.2.1.2   Current Differential with Overcurrent Relay: This circuit uses the differential principle in connecting the CT circuits and an overcurrent relay instead of a differential relay. The scheme has limited use since the CTs from all terminals of the line, line segment, or bus has to be connected by the hardwire circuits back to the overcurrent relay. This connection is more secure and can be set more sensitively than a simple overcurrent relay application. It also can keep one more overcurrent relay from being in a string of overcurrent relays that have to be set with increasing time delay.

The circuit is typically used within a substation or generation plant facility where short line segments or buses require protection that does not need the speed of a differential relay. In applying the circuit, the relay engineer has to be aware of the CT error and mismatch that may occur in the differential circuit to the relay and set the relay over any mismatch that may occur.

The circuit is often applied in a variation as an open-differential circuit. This circuit has a number of lines connected to it with CTs connected in N-1 lines (see Figure 12-5). The overcurrent relay is then set for the load of the line without the CT. This circuit is often applied as a backup circuit to a transformer differential circuit at a substation with an in-and-out transmission line. The relay engineer has to be aware of through faults in the lines with CTs that do not involve the line without the CT. CT mismatch will result in an error current as a result of the through-fault current that will flow to the relay.

12.4.2.1.3   Step Distance Relaying: Since the distance relay responds to the impedance of the device it is protecting, it can more easily be coordinated and used when the coordination of overcurrent relays does not work. The distance relay is more costly than the overcurrent relay and requires the
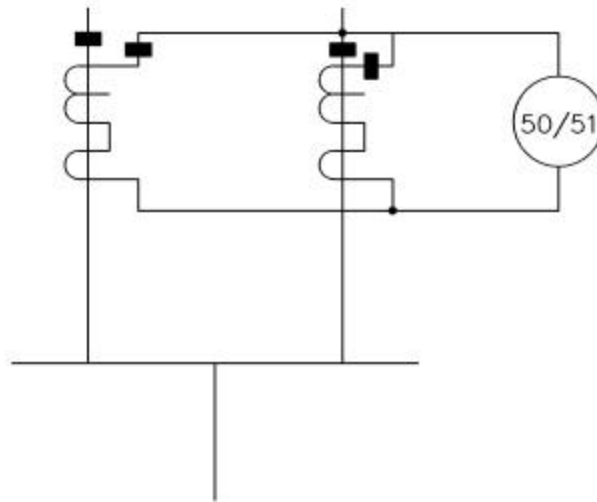
Figure 12-5: Open Differential

addition of line potential sources, adding cost to the scheme. Advantages of distance relays include a fixed reach based on the impedance of the protected device, regardless of the system voltage and current changes; the ability to operate at fault currents less than load current; and little transient overreach.

Two relays are used to protect the total length of the line, providing protection referred to as zones (see Figure 12-6). Zone 1 relay is typically set for 85 to 95 percent of the line impedance. Zone 1 tripping time is set for instantaneous tripping, that is, with no intentional time delay. Zone 2 is typically set to 120 to 150 percent of the line impedance. Zone 2 needs to extend past the line being protected into the adjacent lines, not reaching past the far end terminal of the adjacent lines, yet ensuring the line in question is covered. Zone 2 tripping time is typically set with 18 to 30 cycles of trip delay.
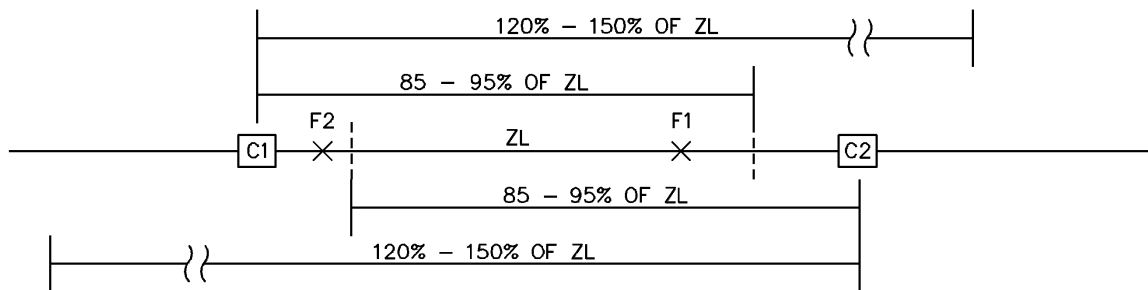
Figure 12-6: Distance Relay Zones 1 and 2

This scheme provides instantaneous tripping for 70 to 90 percent of the transmission line for a fault (F1, Figure 12-6) located within Zone 1 reach for both ends of the line. For the remainder of the line, a fault (F2, Figure 12-6) near each line terminal is cleared in the time delay used for Zone 2. A fault located near a line terminal will be sequentially cleared by the near breaker tripping first and the remote terminal breaker tripping after the Zone 2 trip time delay.

A third zone of protection, Zone 3, is often used in step distance relaying. Zone 3 is usually set to reach through the next line to cover breaker failures. The reach for the Zone 3 relay is usually in the range of 200 to 225 percent of the line impedance. Zone 3 tripping time is typically set with 60 to 120 cycles. The impedance setting will vary depending on the length of the adjacent lines. Because of the reach of the Zone 3 characteristic, it often encroaches on the load impedance and is susceptible to power system swings. Use caution when incorporating Zone 3 relays since long settings can result in tripping on load.

Zone 3 may be reversed to look in the opposite direction of the line to which step distance relays are being applied. This is the case when carrier schemes are applied. Occasionally, a reverse-set Zone 3 relay is used as a local breaker failure relay, indicating failure of adjacent circuit breakers.

Step distance relaying may be difficult to apply when the transmission lines are short, with little impedance. The settings for the distance relays may be very small, near the limits of the design for the relay reach, resulting in the possibility of the relay's overreaching and tripping for adjacent line faults. Three terminal lines will often use distance relays as fault detectors, but will normally require the implementation of a pilot scheme to ensure tripping for all fault conditions.

12.4.2.2   Pilot Schemes: Pilot schemes simultaneously measure and monitor system parameters at all terminals of a transmission line, local and remote, and then respond according to their predetermined functions. These schemes require the use of a communications channel that may be provided through pilot wires, microwave, fiber, or power line carrier. If the measured parameters exceed threshold values, appropriate actions are initiated.

Pilot schemes can generally be broken into two primary categories. Those categories are directional comparison and phase comparison. Directional schemes use directional distance relays for phase fault detection and either directional distance relays or directional overcurrent relays for ground fault detection. The decision to trip is based on relay setting thresholds being exceeded and the faults being located in the predetermined direction for trip.

Phase comparison schemes are an extension of the differential protection principal. Currents from all line terminals are converted into a composite signal, transmitted to the remote terminals, and compared to the local terminal composite signal. The result of the comparison will result in a trip if the relay setting threshold is exceeded. Phase comparison schemes are inherently directional and secure, not tripping for faults outside the protected zone of protection.

12.4.2.2.1   Directional Comparison: Directional comparison schemes are divided into four categories:

1. **Blocking Schemes**
   Directional comparison blocking uses distance relays as directional indicators and block initiation for phase faults. Either distance or directional overcurrent relays may be used for ground fault indicators and block initiation. Each terminal has trip and start relays. The trip relay reaches toward the remote terminal and a little beyond. The start relay reaches backwards, away from the protected section. The trip relay attempts tripping when it operates unless it is stopped by receipt of a blocking signal (carrier, audio tone, or microwave) from the remote end. The start relays at each end initiate the blocking signal. Thus, if only the trip relays see the fault, it is within the protected section and both ends trip. If the fault is just outside one end, the start relays at that end operate and send a block signal to the remote end, which would otherwise trip. The ground relays operate similarly.

A tripping delay is necessary to allow for the receipt of the blocking signal. A typical delay time of 6 to 16 msec is used to coordinate for the channel delay in communications. The communication channel is not required for tripping the breakers since the breakers will trip in the absence of the blocking signal. Failure of the channel could result in overtripping of the breakers for adjacent line faults within the reach setting of the distance relays. Blocking directional comparison is commonly used with on/off type carrier facilities. Since it is not necessary to drive a signal through a fault to operate this scheme, it is the most popular carrier relaying system. See Figure 12-7.
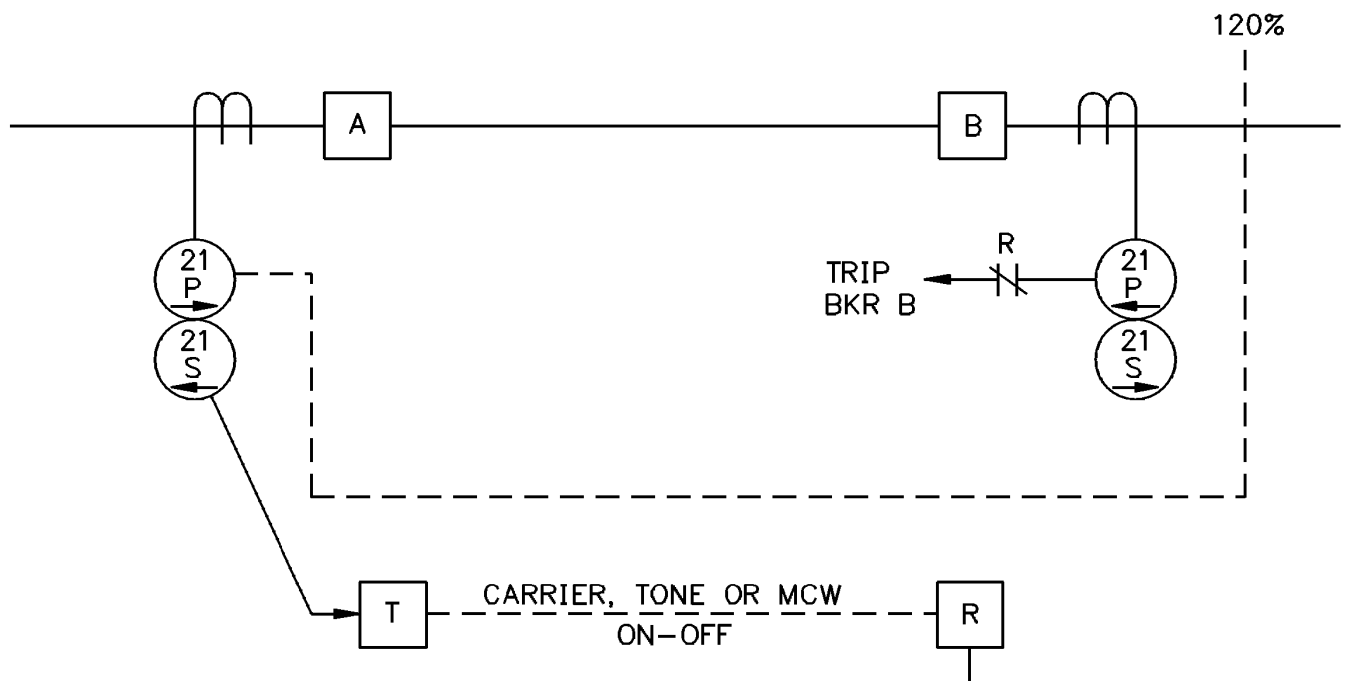
Figure 12-7: Blocking Directional Comparison

2. **Unblocking Schemes**
Directional comparison unblocking is similar to the blocking scheme except that the start relays are deleted and the blocking, "guard" signal is sent continuously. See Figure 12-8. The communication signal for an unblocking scheme uses a frequency shift keying (FSK) channel.

For an internal fault, the frequency is shifted to the unblock, "trip" frequency. The receivers receive the trip frequency and close the output contact, which in series with the 21P relay output contact will trip the breaker. For an external fault, within the reach of one of the 21P relays, the distant 21P relay will see the fault while the local 21P relay will not see the fault since it is behind the relay. The distant 21P relay will shift its transmitter frequency to trip. The local 21P relay will not send the trip frequency or close the 21P output contacts. The line

thus stays in service. Should the receivers fail to receive a guard signal and a trip signal, the receivers will allow typically 150 msec of receiver contact closure to permit the 21P relay contact to trip the line. After this time limit, the communication channel will lock out.
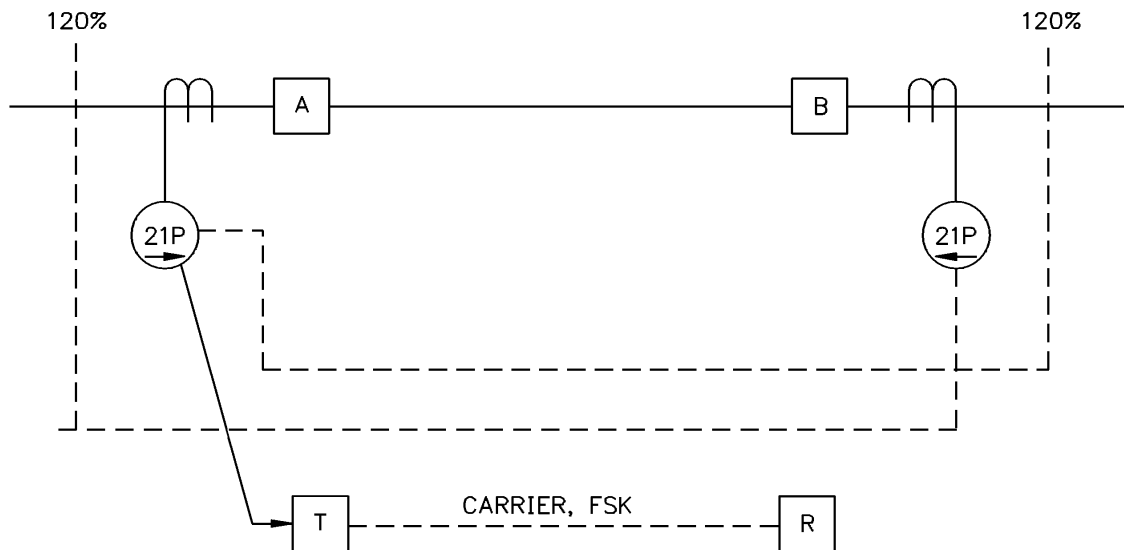
Figure 12-8: Directional Comparison Unblocking

This scheme is more secure since overtripping is avoided at all times with the exception of the 150-msec interval during the loss of signal. Reliability is improved since the communication channel operates continuously and can be monitored, providing an alarm in the case of failure. The scheme is applicable for two-terminal and multi-terminal lines. Separate channels are required between each pair of line terminals.

3. **Overreaching Transfer Trip Schemes**
Permissive overreach is also a simple scheme, requiring only one overreaching fault detector at each terminal. This fault detector sends both a trip signal and attempts local tripping through a contact on the receiver. If both relays see a fault, both ends trip simultaneously. The scheme appears similar to the directional comparison unblocking scheme of Figure 12-8.

A trip signal is required for this scheme to trip. Power line carrier channels therefore are not recommended for these schemes since a fault could short out the carrier signal. These channels are normally used with audio tones with frequency shift keying over microwave, leased line, or fiber-optic communications.

The overreaching transfer trip scheme provides highly secure transmission line protection since a trip signal is required from both ends of the line for tripping to occur. The dependability of the scheme may be less than the blocking schemes since the trip signal has to be received before the tripping is initiated. The scheme is often used when an existing non-piloted scheme has communications added for piloting.

4. **Underreaching Transfer Trip Schemes**
    Underreaching transfer trip schemes include two variations: direct underreach and permissive underreach.

    The communications for this type of relaying are generally the same as for the overreaching systems, using audio tones with frequency shift keying over microwave, leased line, or fiber-optic communications channels.

    a. **Direct Underreach**
        This form of protection requires only a single distance fault detector at each end. It has to be set short of the remote end and will simultaneously trip the local breaker and send a trip signal to the remote end, which then trips directly upon receipt of the signal. Note that local confirmation is not required upon receipt of a trip signal. Though this scheme is the least complex, it is seldom used because of the high risk of false outputs from the communication channel, which would result in false trips. This risk can be minimized by using a dual-channel transfer trip, which requires the receipt of two signals from the remote end to effect a trip. See Figure 12-9.
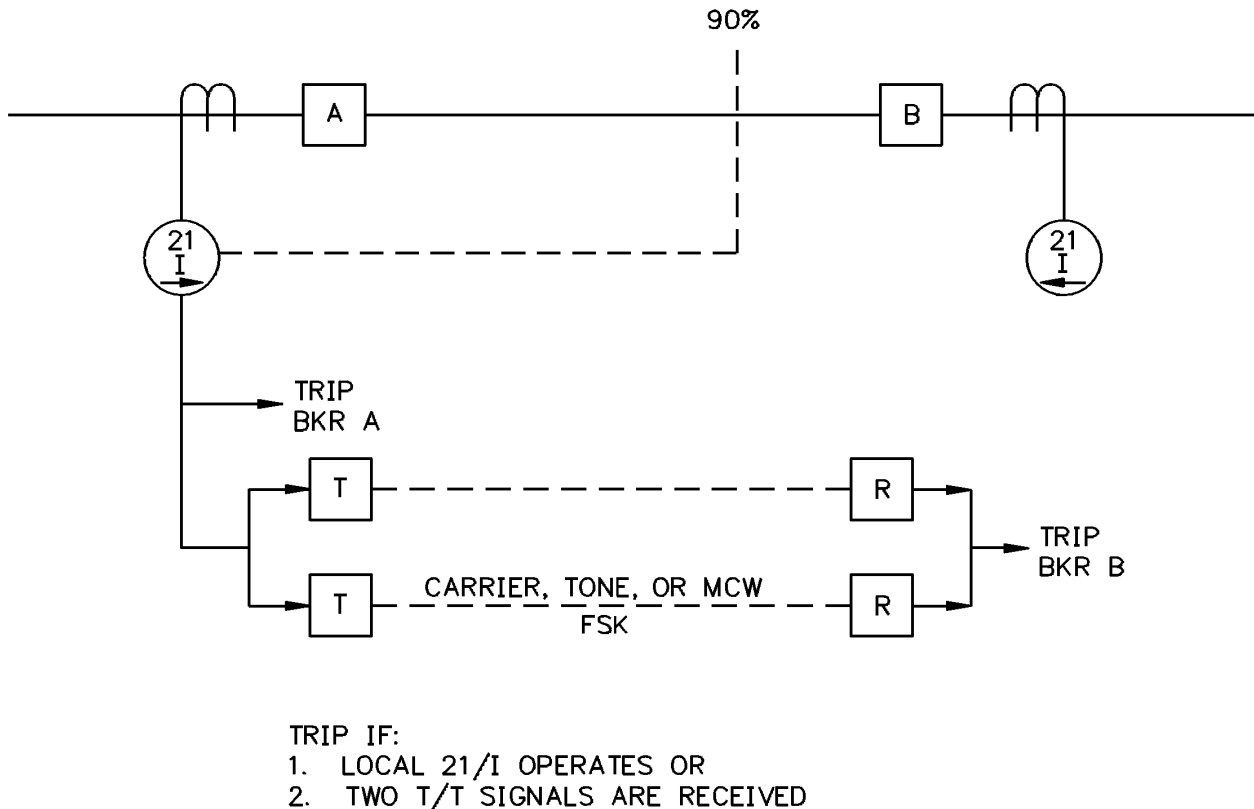
Figure 12-9: Direct Underreach

b. **Permissive Underreach**
This scheme is identical to the direct underreach scheme with the addition of an overreaching fault detector. The transfer trip signal requires local confirmation by this fault detector before tripping can occur. This increases the security of the scheme and the consequent range of application. It is commonly selected when an existing step distance relay line is to have the pilot added. See Figure 12-10. Carrier is not normally used since a fault could short out the communication signal and prevent the signal from reaching the remote terminal.

TRIP IF:
1. LOCAL 21/I OPERATES OR
2. LOCAL 21/P OPERATES AND 1 T/T SIGNAL IS RECEIVED
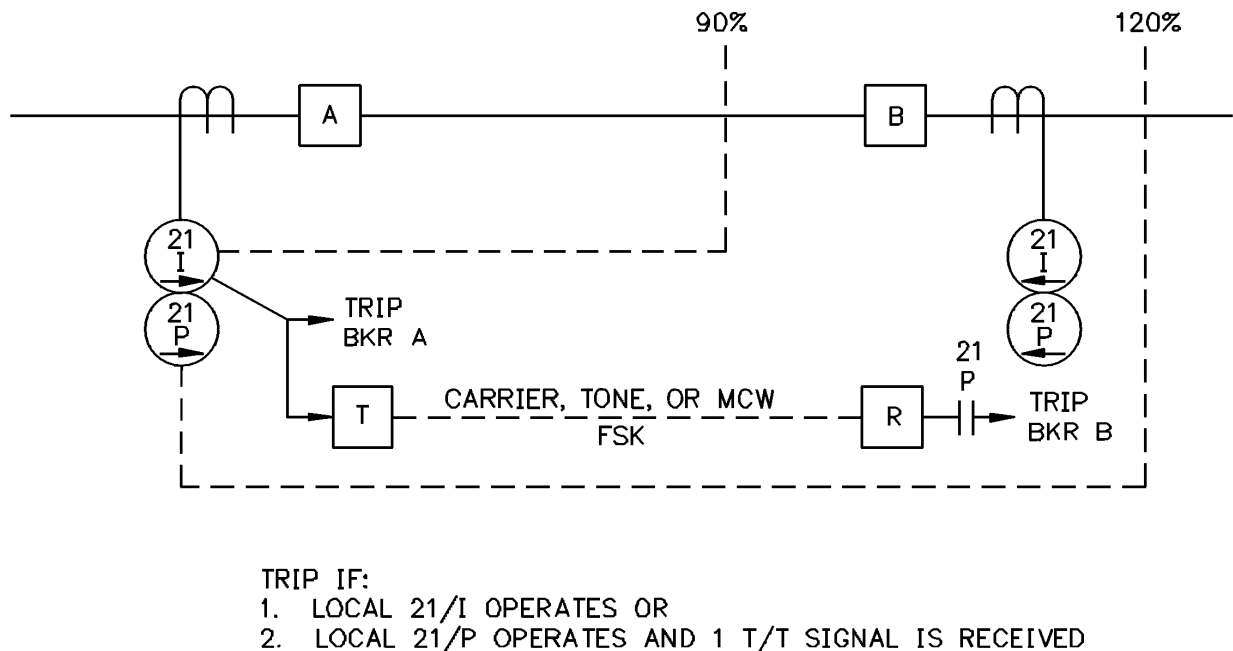
Figure 12-10: Permissive Underreach

12.4.2.2.2 <u>Phase Comparison</u>: Phase comparison relay systems monitor the current direction at each line terminal of the protected line and transmit this information to the other terminal via a communication channel. Each line terminal compares local and remote current direction and trips if the current is into the line from both terminals. The communication channel is normally an on/off type of communications, transmitting only when the overcurrent detector's thresholds have been exceeded. This system is immune to tripping on overloads or system swings since it operates on current direction only. It needs no potential source unless it has to be supervised by distance relays because of low fault currents.

Current or distance fault detectors are used to supervise tripping. These detectors have to be set above line charging current, which can appear to the relays as an internal fault at low loads. Internal timers have to be set to compensate for the transit time of the communication channel. One of the most popular applications of this system is on lines with series capacitors because it is less likely that such a current-operated scheme will operate incorrectly for faults near the capacitors.

1. **Pilot Wire**
    This scheme is a form of phase comparison since it compares current direction at each terminal. The difference between this scheme and others is that a pair of telephone wires is used as the communication channel. A special filter in the relay converts the three-phase currents to a single-phase voltage and applies this voltage to the wires. When current flows through the protected section, the voltages at each end oppose each other and no current flows in the operate coils. When current enters the line from each end, the voltage on the pilot wire reverses to allow current to circulate through the operate coils and consequently trip both ends. Special monitor relays sound an alarm if the pilot wire pair becomes open or shorted. The wire line has to have adequate protection against induced voltages and a rise in station ground potential but may not use carbon block protectors because the line has to remain in service while the protection is operating. Neutralizing transformers and gas tubes with mutual drainage reactors, all with adequate voltage ratings, comprise the preferred pilot wire protection package.

    This relaying has the advantage of simplicity and does not require a potential source. It does not provide backup protection. Its application is limited to short lines a mile or so in length because of pilot wire cost and increased exposure. The system's dependability is based on the integrity of the pilot wires themselves. Many pilot wire systems have been replaced with other pilot schemes because of the failure of the pilot wire system to function reliably and securely. Recently, pilot wire systems have been replaced with fiber-optic systems providing the communications systems, using a module to convert the output voltage to a light signal. These modified systems have provided a more dependable and secure protection system.

2. **Single-Phase Comparison**
    This scheme applies a sequencing network to the current inputs to the relay to produce a single-phase voltage output. This output is proportional to the positive, negative, and zero phase sequence components of the input currents. This signal is squared so that the positive portion of the signal provides the positive portion of the square wave. The negative portion of the signal provides the zero portion of the square wave. Two fault detectors are normally used to provide security, with the more sensitive detector used as the carrier start to transmit the signal to the remote end. The less sensitive detector is used to arm the comparison module for a trip upon the correct comparison of the local and remote signals. See Figure 12-11.

    Normally current-operated units are used as the fault detectors. In a case where the fault current is less than the load current, impedance-operated units may be used for fault detection. The use of impedance fault detectors will increase the cost of the system because of the necessity of having line potentials for the operation of the relay.

3. **Dual-Phase Comparison**
    This scheme is similar to the single-phase comparison scheme except that square wave signals are developed for the positive and the negative portions of the single-phase voltage output of the sequencing network. Each signal requires a separate channel for the transmission of information to the remote site. This scheme can provide a slightly higher speed of detection since faults are detected on both the positive and the negative portions of the single-phase voltage output of the sequencing network. This scheme is normally used with a frequency-shift channel, which is continuously transmitted. On a power line carrier it is configured as an unblocking scheme.
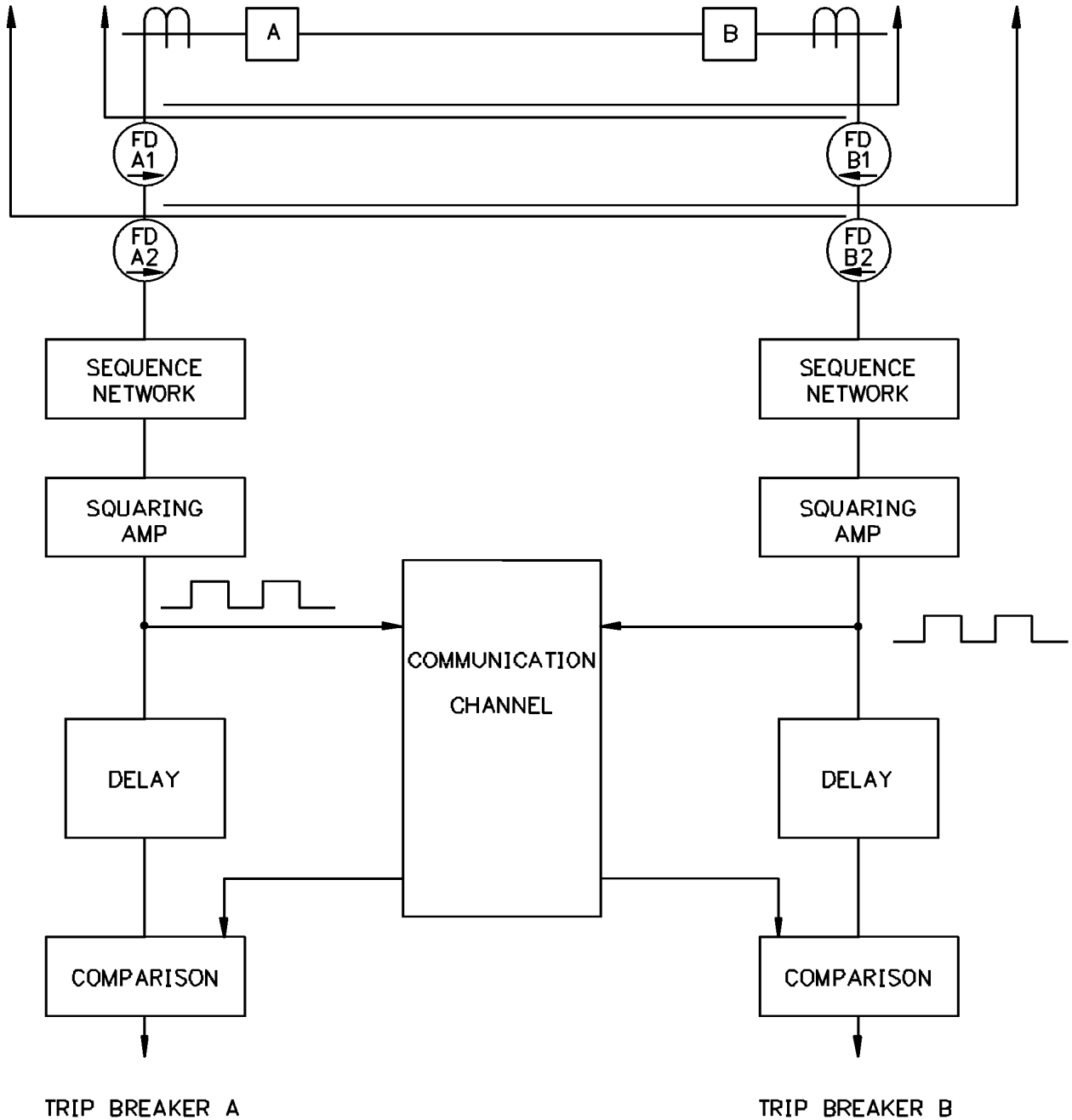
Figure 12-11: Single-Phase Comparison

4. **Segregated Phase Comparison**
    This scheme is similar to the single-phase comparison scheme except that a square wave is developed for each phase of the transmission line. A communication channel is required for each phase to provide communications to the remote terminal. Comparisons are made on each

of the three phases. The operation of the scheme is basically as described above in the previous phase comparison schemes.

12.4.3 Distribution Feeder

Distribution line switching and protection within the substation are provided by circuit breakers, reclosers, or fuses. The selection of the protective devices to be used on any particular feeder will depend on the load being fed by the feeder, the magnitude of loads being served, any special protective requirements necessitated by the load, and the cooperative's preferences in design and operating practices. In addition to the above-listed items, sectionalizers may be located on the distribution feeders for additional segmenting of the line during fault conditions.

12.4.3.1 Circuit Breakers: Circuit breakers will most commonly use overcurrent relays to provide fault protection at a substation. Historically, on a typical radial distribution feeder, two phase and one ground (if the system is grounded) nondirectional inverse time overcurrent relays with instantaneous elements will be the minimum relays that are applied that will detect all phase and ground faults when properly coordinated. Often, a third overcurrent relay is applied to the phases. This will provide complete protection for faults if one of the relays should be disabled. This also permits the removal of one of the relays for testing outside the case, providing protection for the feeder without taking the feeder out of service. With today's microprocessor relays, three-phase relays and the neutral relay are applied to detect all faults when properly coordinated. The time–current characteristic chosen for coordination of protective devices will depend on what downstream devices are present on the feeder. See Figure 12-12.
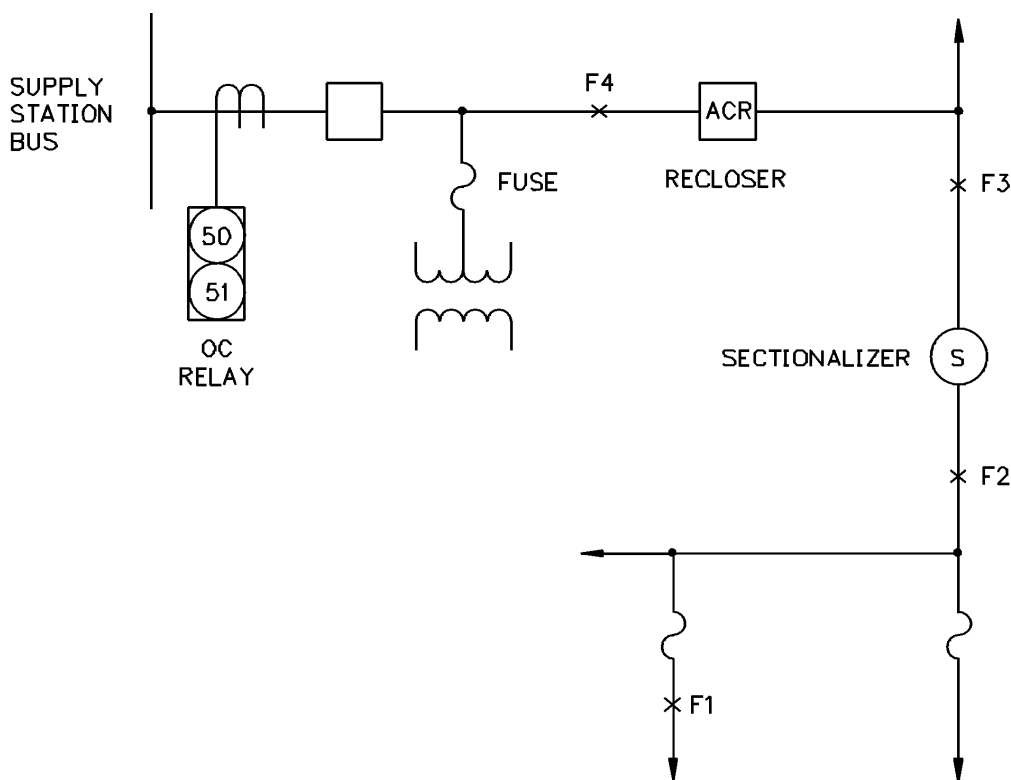
Figure 12-12: Distribution Circuit Protective Elements

Other protection may be provided in addition to overcurrent relays, such as voltage-controlled overcurrent relays and negative sequence relays. Special circumstances on a feeder will allow specific relays to be applied to address those circumstances. Microprocessor relays will often have a number of protective functions available that may be used for special circumstances. Relay protection for circuit breakers may be more readily customized and applied to special situations. Many of the microprocessor relays available for distribution feeder protection also include multiple setting groups. This feature will allow a relay to be set for a particular configuration. Should the configuration change, the setting group can be changed, either automatically or manually, to provide for different settings to adjust the relay protection to the new configuration.

12.4.3.2   Automatic Circuit Reclosers: Reclosers are devices similar to circuit breakers but more compact and self-contained so that they may be used within the substation or mounted on poles out on the distribution feeder. The controls permit various combinations of instantaneous and time-delayed trips and automatic reclosures so that coordination may be accomplished with both upstream and downstream devices. Reclosers may be single- or three-phase interrupters. Single-phase reclosers are series trip devices, and three-phase reclosers may be either series trip or nonseries trip devices. Nonseries trip reclosers usually employ a solid-state control and have a self-contained battery. Some single-phase reclosers are available with electronic controls.

Single-phase reclosers usually provide better service reliability to rural distribution circuits because a fault to ground on one phase will not trip the other phases. However, where loads are predominantly three phase, or where the load on the circuit is large, three-phase reclosers with ground trip settings are desirable to achieve the required sensitivity for ground faults.

Microprocessor controls are also available for reclosers. The microprocessor adds much flexibility to the controller and provides additional functions, similar to many of the microprocessor relays. Also, many additional protective characteristics (curves) are typically available in the microprocessor controls. There is normally a communications port available on the control that can then provide data to remote sites.

12.4.3.2.1   Sectionalizers: These devices, located outside the substation on the distribution lines, are similar to reclosers, except that they do not interrupt fault current. Instead, the sectionalizer counts trips of an upstream recloser and opens its contacts during a de-energized period following a predetermined number of recloser interruptions. Sectionalizers can, however, interrupt load currents within their rating. See Figure 12-12.

12.4.3.2.2   Fuses: Fuses are used both to protect connected distribution transformers and to protect sections or branches of the distribution circuit. Occasionally, they are used within the substation for protection of a feeder or as backup protection for a bypass switch around a recloser or a breaker. They are most commonly supplied in outdoor holders that are combination fuseholders and disconnect switches. Fuses are usually applied as the farthest downstream device in a sectionalizing scheme because of their nonrepeating nature. An upstream recloser trips and recloses several times with the accumulated "on" time being sufficient to blow the fuse during a delayed trip. The recloser then resets before the trip occurs.

12.4.3.2.3   Coordination: Coordinating these devices on a distribution circuit involves the progressive disconnecting of sections of the distribution circuit beginning at the end farthest from the station until the fault is removed. Since several different types of devices are involved, this process can be more complex than coordinating a transmission line.

Referring again to Figure 12-12, it may be seen that a fault at Fl should be interrupted by the fuse. This means that the relay, recloser, and sectionalizer has to be programmed so that they will let enough accumulated fault current through (integrated over several reclosures) that none of these devices locks out. Generally, the recloser will have one fast and three delayed trips in such a situation. Time curves will be selected so that the fuse will blow during the second delayed trip. The sectionalizer would be programmed to open following the second delayed trip to clear a fault at F2. A fault at F3 would then be cleared when the recloser locks out following the third (delayed) trip. The relay would be set to clear a fault at F4 but coordinated with the line recloser so as not to trip for a fault at F3, paying careful attention to overtravel and reset time of electromechanical reclosers following each successive interruption.

This is a simplified example of distribution coordination and ignores complications, such as long branches and improperly applied protective devices, both common occurrences on real distribution systems. In such cases, compromises have to be made and areas of nonselectivity accepted. The coordination process involves moving these areas of nonselectivity into positions where they do the least harm.

12.4.4   Major Equipment

12.4.4.1   Transformer and Reactor Protection: Transformers are protected by fuses or circuit-interrupting devices such as breakers or circuit switchers with relays detecting faults and providing trip signals to the circuit-interrupting devices. Transformers 5 MVA and below are almost always protected by fuses. Relay protection of transformers is most often used for transformers rated 10 MVA and above although there are transformers up to 30 MVA that are protected by fuses.

Fuse protection has the merits of being economical and requiring little maintenance. Fuses require no circuit-interrupting devices such as circuit breakers or circuit switchers and no battery power systems for auxiliary power. Auxiliary equipment that would normally be located within a control building is minimized, resulting in the reduced need for and cost of a control building. Fuses will provide protection for primary and secondary external faults, but little protection for transformer internal faults. Fuses introduce the probability of creating a severely unbalanced (single-phasing) voltage condition for secondary loads should only one fuse blow. Proper coordination with secondary devices is essential to avoid this condition.

Relay protection for the larger size transformers usually includes sudden pressure relays, differential relays, overcurrent relays or directional phase distance relays, and ground overcurrent relays. See Figure 12-13. Sudden pressure relays are often considered by many to be the primary relay protection on a transformer. The sudden pressure relay is sensitive to the sudden changes in pressure in the transformer tank that occur during an internal fault. Differential protection is a primary scheme of protection that is normally applied on a percentage differential basis to allow for differences in transformer ratios, magnetizing current, and current transformer mismatch. Overcurrent relays are often applied on the primary voltage winding to provide backup protection to the differential relay protection. If the overcurrent relays may not be coordinated with the secondary main and feeder relays, a directional phase distance relay may be applied. A ground overcurrent relay is normally applied to provide increased sensitivity to ground faults.

Figure 12-13 indicates the possibility of using local primary and secondary breakers. Because of economics, a primary breaker is sometimes not used. Tripping of the transformer is accomplished by sending a transfer trip signal to the remote substation using a communications signal or a high-speed ground switch. The time required to isolate the transformer is increased by the communication channel time or the time for the remote relay and breaker to clear the fault established by the high-speed ground

OPTIONAL CT CONNECTION
IF LOCAL PRIMARY BREAKER
IS USED

50H
51H

63

87   86

TRIP LOCAL
BREAKERS

Y

TRANSFER TRIP
REMOTE PRIMARY
BREAKER

50L
51L

OPTIONAL

51N

OPTIONAL CT CONNECTION
IF SECONDARY BREAKER
IS USED

BUS
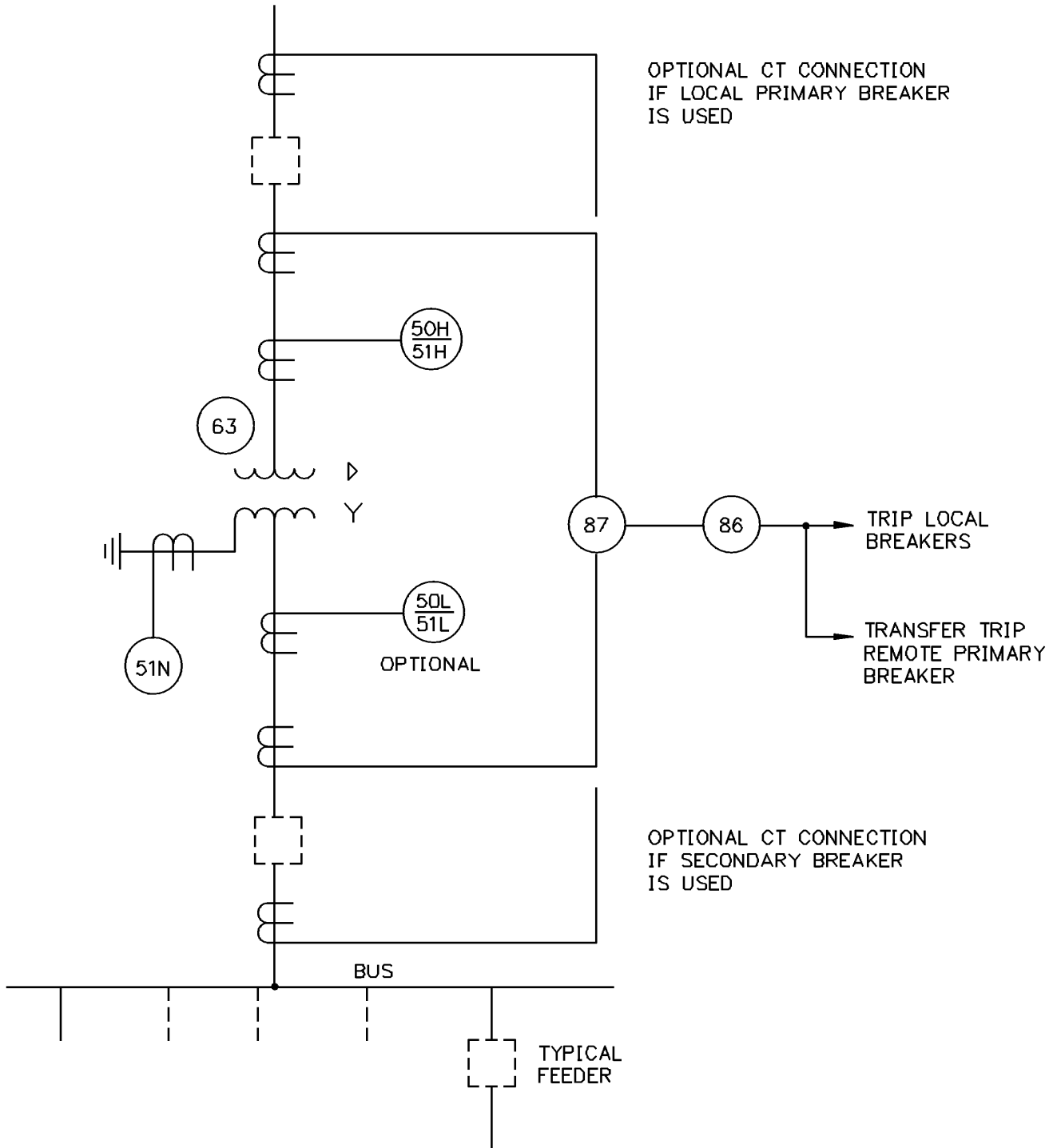
TYPICAL
FEEDER

Figure 12-13: Typical Transformer Relay Protection

switch. Secondary breakers are often not used. The engineer will have to decide whether or not to trip all the feeder breakers or to manually open the feeder breakers before re-energizing the transformer. Reactors may be protected by generator-type differential relays with phase and ground overcurrent backup relays. Occasionally, phase distance relays are used for backup.

Additional means of protection applied to transformers and reactors include negative sequence relays, overvoltage relays, and thermal relays. Negative sequence relays can be set sensitively to back up differential relays since they do not respond to load current. Overvoltage relays will protect the transformer from excessive system voltage that will result in excessive transformer magnetizing current and heating of the transformer core. Thermal relays provide additional protection for the transformer against internal heating as a result of overloading the transformer.

Each transformer installation should be individually evaluated for the type of protection that is to be applied.

12.4.4.2   Bus Protection

1. **Remote Tripping for Bus Fault**
   Short-circuit faults on buses can be isolated by allowing remote substation breakers on all lines that feed into the faulted bus to trip by Zone 2 or time-delay ground relay. This type of bus protection is simple and the most economical. It has the disadvantage that any loads fed by lines to the remote substations are also removed from service. Another disadvantage is that the time necessary to clear the fault may be intolerable.

2. **Local Tripping for Bus Fault**

   a. In distribution substations, the bus protection is often provided by overcurrent relays, phase and neutral, located on either the low-voltage or high-voltage side of the transformer. See Figure 12-13. The phase relays have to be set to coordinate with the feeder relays and any additional downstream devices. This results in a slow trip time for the clearing of the bus. Each bus has to be evaluated to determine if the time delay that will be experienced by this type of protection will be excessive and if this type of protection will be adequate. This bus protection scheme is very simple and may also be able to act, in part, as backup protection to the feeder relays.

   b. Short-circuit faults can be removed by a bus protective scheme in which all the substation breakers associated with a faulted bus are tripped. The two basic types of bus protective schemes are current differential and voltage differential. The current differential scheme connects all the current transformers on all the circuits connected to a bus in parallel, and the relays operate on the unbalanced current that exists during fault conditions. See Figure 12-14. During normal conditions, there should be no unbalanced current, since the current entering a bus has to equal the current leaving a bus. Restraint coils help to compensate for unequal current transformer performance during external faults, but the scheme still has to be applied carefully on buses with high short-circuit capabilities.

   Voltage differential schemes use the same parallel connection but connect a high-impedance voltage element across the parallel. It is possible to set this voltage element well above the worst case external fault voltage and still retain adequate sensitivity for internal faults. This type of relay performs well on buses with high short-circuit capability.

BUS
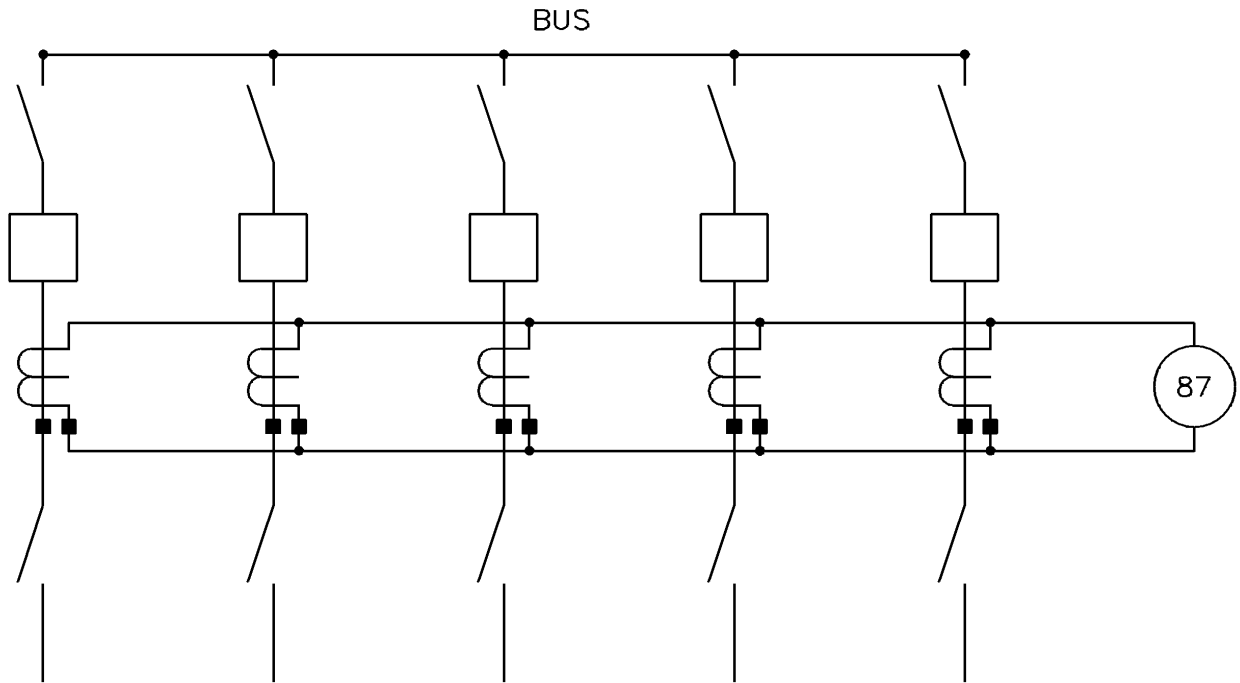
Figure 12-14: Bus Differential Relay Protection

In some cases, overcurrent relays are applied to the differential circuit. This provides an inexpensive relay for use in the operation of the differential circuit. The disadvantage of the overcurrent relay is that there is no restraint in each of the relay circuits. Any mismatch in the CTs has to be taken into consideration in the settings of the relay by using a higher pickup amperage or a longer time delay. This will make the operation of the circuit slower than the times provided by differential relays. Many times this time delay is unacceptable for the coordination with the rest of the system relays.

c.   Since the recent use of the microprocessor relay that normally provides additional functions at a relatively inexpensive cost, a pseudo bus differential scheme has been applied. This scheme uses a combination of instantaneous relay elements from the secondary main bus relay and the feeder relays to detect whether the fault is on the feeder or on the bus. See Figure 12-15. This scheme requires that there be no fault sources on the feeders since the operation of the feeder instantaneous elements for reverse feeder current would make the fault look like a feeder fault and cause the scheme to fail. If fault sources are located on the feeders, directional instantaneous overcurrent relays have to be used. An instantaneous element is used on the main breaker relay with a setting that is ensured to pick up any bus fault. The instantaneous elements of the feeder relays have to be set to reach out farther than the main breaker relay so that, for any close-in feeder fault that the main breaker relay will see, the feeder relay will also see and disable the circuit. For a bus fault, the feeders will not see the fault so the relay takes no action. The main breaker relay sees the fault, closes its contact, and, after the appropriate time delay, trips the breaker. This circuit will be slower than an actual differential relay circuit operating time, but will be faster than the overcurrent relay in protecting the bus from damage.

TRANSFORMER

MAIN BUS RELAY

MAIN BUS BREAKER

FEEDER
RELAYS

FEEDER
BREAKERS

FEEDERS
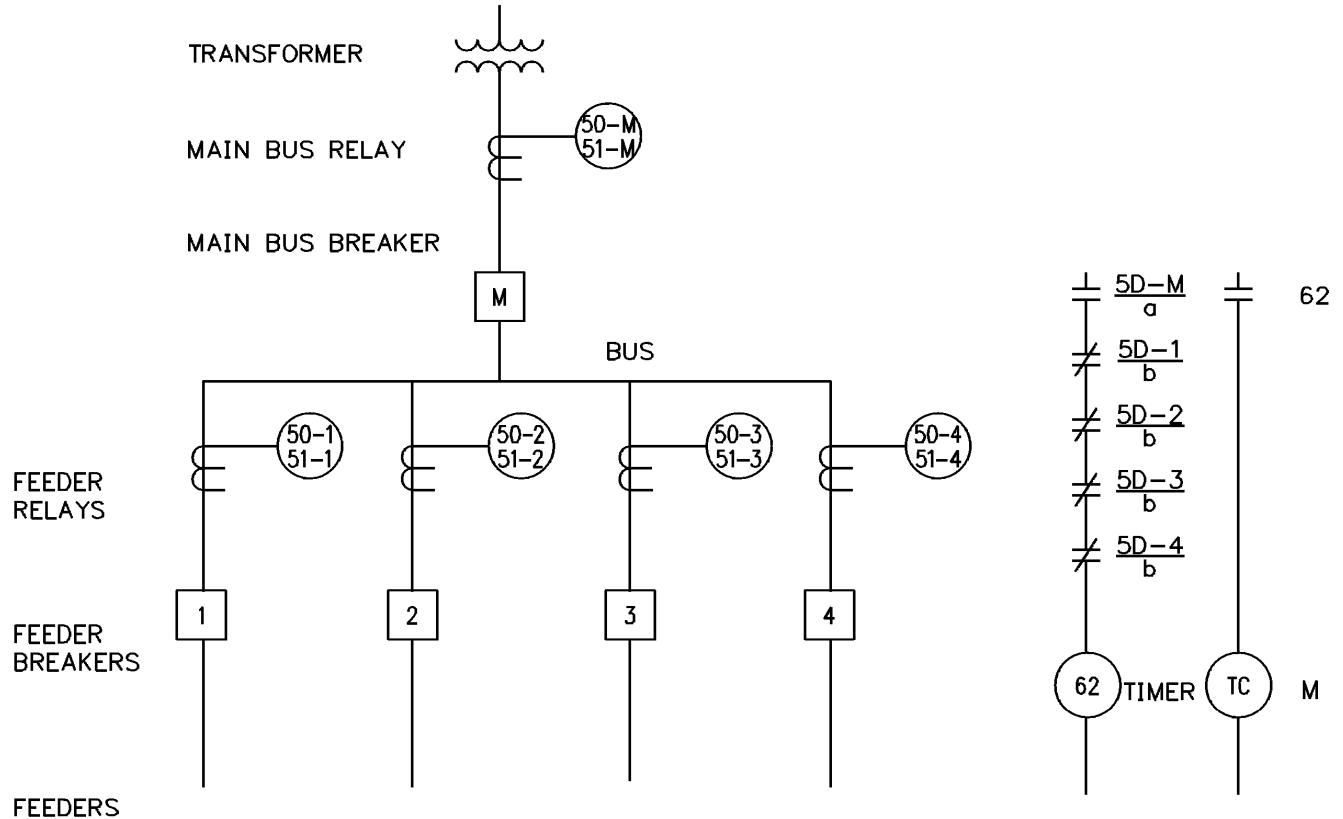
Figure 12-15: Pseudo Bus Differential Circuit

d. Local tripping for a bus fault may be accomplished by the use of a reverse-looking Zone 3 element from a distance relay. Zones 1 and 2 on a line are set to look out on the line, away from the bus. Often, the Zone 3 element is set to look in the reverse direction, which will see the bus behind it. Through a timer, the Zone 3 may be set to trip through-bus faults.

12.4.4.3   Breaker Failure Protection: Breaker failures can normally be separated into two classes: the failure of the breaker itself and the failure of the relaying associated with the breaker. Schemes developed to protect for the failure of breakers are based on providing either remote backup or local backup. Failure of the breaker results in the necessity to trip all the adjacent breakers in order to clear the fault and to isolate the failed breaker.

1. **Remote Backup**
    Remote backup normally consists of a Zone 3 distance relay and/or ground time overcurrent relay set to cover lines contiguous to the line being protected. This scheme will provide protection for breaker failure regardless of whether the failure is a result of relay failure or breaker failure. It will normally see faults on the protected line plus faults on the next bus and line adjacent to the protected line. This scheme has the advantage of simplicity. Complications in using the scheme include that the relay has to be set above the maximum load current that is carried on the lines, yet it has to be set sensitively enough to see the faults that may occur on the lines. Faults occurring at the remote ends of the lines may not be detected because of insufficient current flow. When applied on a system where the adjacent

bus has a number of lines with varying length, the settings for the relay may extend beyond the adjacent lines resulting in overcoverage and overtripping. When adjacent lines are multi-terminal lines, a number of terminals may be unnecessarily tripped by remote backup. Longer reach Zone 3 relays are more susceptible to out-of-step system swings. Even with its shortcomings, in some situations with its inherent economics, this scheme may provide acceptable backup performance.

2. **Local Backup**

   a. A simple means of providing local backup protection is to use the Zone 3 relay looking in the reverse direction. This provides a degree of protection for local equipment including all adjacent breakers, bus, lines, and remote terminals. Advantages and disadvantages in the use of this scheme are included in the discussion above on remote backup.

   b. An additional means of providing breaker protection is to add timing to the primary relays. If the relays do not trip and the fault is still on the system within the set time of the timer, the timer will act to trip all adjacent breakers. This scheme depends on the proper action of the primary relays and provides no backup to the failure of those relays.

   c. An additional scheme provides the use of a second set of relays to back up the primary relaying. Carried to the maximum limit, a second dc tripping system is provided including battery, panels, charger, relays, breaker trip coils, CTs, and potential devices. This degree of duplication is occasionally provided for EHV systems. Higher voltage systems including 69 kV and above will often provide dual trip coils in the circuit breakers, and primary and secondary relays with dual dc trip buses. The engineer has to decide if auxiliary dc power systems will be duplicated, including power panels and chargers; often both systems are fed from a common battery. The reduced cost of relaying afforded by the development of microprocessor relays makes this option a relatively economical option to provide backup protection for relays. This scheme does not provide for the tripping of adjacent breakers in the case of the failure of the breaker mechanical mechanism to trip the breaker and clear the fault.

   d. Full breaker failure backup includes protection for the failure of relays and the failure of the breaker. A separate backup relay that acts to trip all adjacent breakers, including remote breakers by means of a transfer trip, provides this degree of backup. Figure 12-16 indicates a typical configuration for a local breaker failure relay. Indicated are primary and secondary relays, dual trip coils in the breaker, and the fault detector and timer associated with the breaker relay. Should either the primary or secondary relay call for a trip of the breaker, an auxiliary relay, 62X or 62Y, keys the timer. If the fault is not removed during the setting for the timer, the 86BF lockout relay is picked up to trip all adjacent breakers and transfer trip any remote breakers. The time setting for the timer is usually in the range of 10 to 20 cycles. If either the protective scheme resets or the current relay drops out within the set time, nothing happens.

12.4.5   Reclosing

12.4.5.1   General: Protective relays detect faults or abnormal conditions. These faults or abnormal conditions can be transient or permanent. For open-wire overhead circuits, such as most of the distribution lines, most faults are transient faults, caused for example by lightning, that can be cleared by disconnecting the circuit from the power source. Service can be restored by reclosing the disconnecting
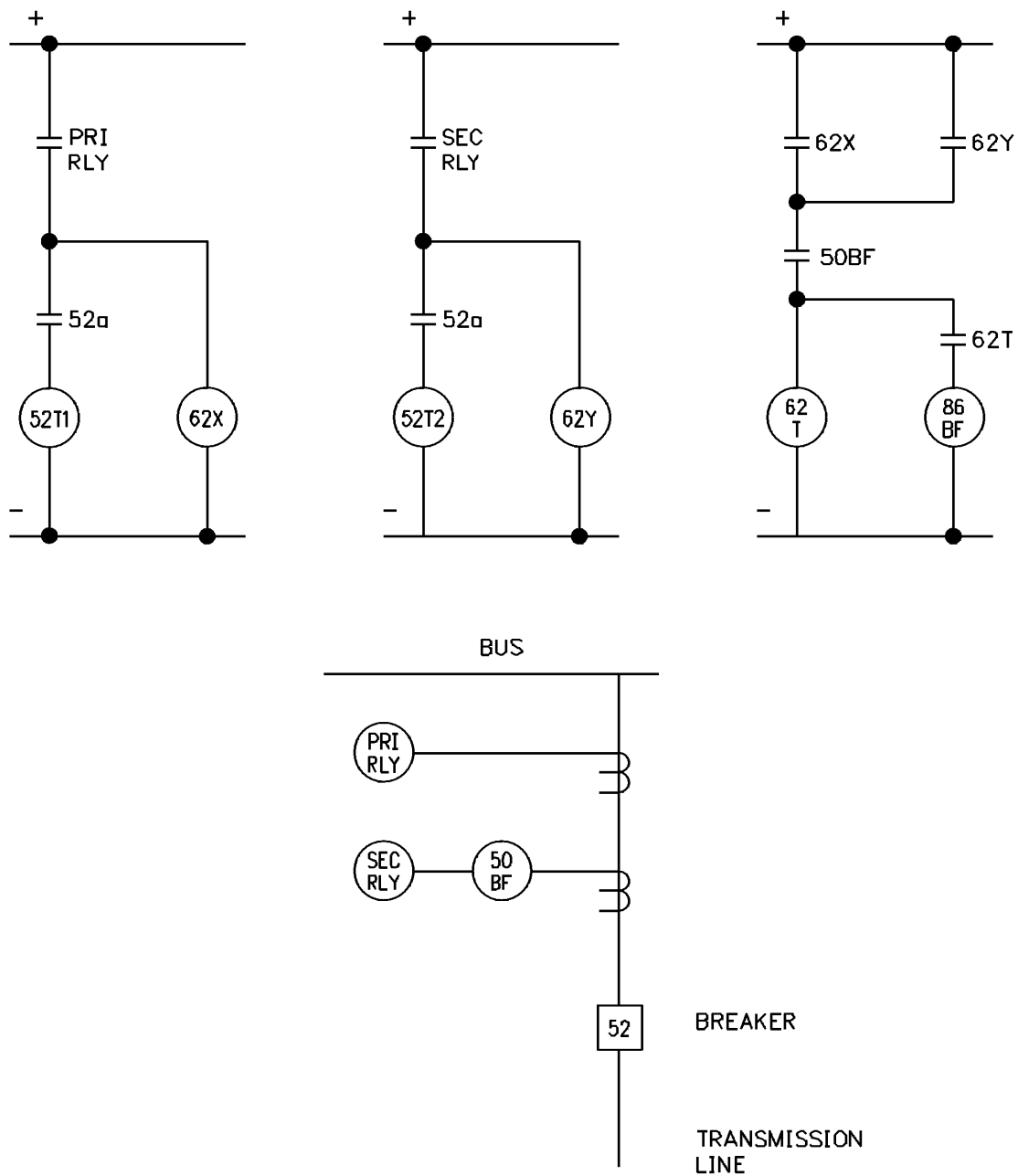
Figure 12-16: Typical Breaker Failure Relay Scheme

device. Certain abnormal conditions, such as overheating of motors, can be relieved by reducing the load on the motor. The motor starters thus can be safely reclosed after the motor has cooled off. The disconnecting device can be reclosed either manually or automatically. Manual reclosing is performed by following the same procedures used in closing the device. Automatic reclosing is usually performed by automatic reclosing relays. Reclosing is generally not applied where permanent faults are more likely, such as on cables.

12.4.5.2 **Automatic Reclosing Relays :** Automatic reclosing relays permit the circuit disconnecting device, usually a breaker, to close one or more times when the breaker has been tripped by protective relays. Relays that permit one reclosing operation are called single-shot reclosing relays, while relays that permit more than one reclosing operation are called multishot reclosing relays. Single-shot reclosing relays can be either the manual- or self-reset type. The manual-reset types have to be manually reset after each automatic reclosing operation to obtain succeeding automatic reclosing operations. The self-reset types automatically reset if the breaker remains closed for a predetermined time. Multishot reclosing relays are of the self-reset type. Automatic reclosing can take place either instantaneously or with time delay, when the line is de-energized or energized, or when the voltages on both sides of the breaker are synchronized. On radial circuits, the first reclosure is usually instantaneous, with additional reclosures, when used, taking place after some time delay. On loop or multiterminal distribution lines, instantaneous reclosing is generally not used unless special forms of protective relaying are applied to ensure simultaneous operation of all line breakers for all line faults. After a specified number of unsuccessful automatic reclosure attempts, the breaker is usually locked open.

12.4.6 Coordination

When a circuit element such as a line, transformer, or bus becomes faulted, it has to be removed from service. This, as has been previously stated, is the function of the protective relay system. Coordination is the process of ensuring that only those elements of the power system that has to be removed to clear the fault, and no more, are tripped in the shortest time possible.

As previously discussed, some schemes are inherently selective in tripping the protected equipment. Such protection schemes include differential schemes and transmission line phase protection that are differential in nature. No additional coordination is required for these schemes.

Coordination with distance relays is the easiest to accomplish. Since such a relay's reach is constant under all system conditions, the instantaneous zone is typically set short of the remote end of the line by 10 percent, and it will never trip for any condition but a fault on the protected section. With the remote end set the same, 80 percent of the line is thus covered by instantaneous protection. To cover the remaining 20 percent, the second zone can be relied on or a piloted scheme can be added. The second zone reaches beyond the protected section and so it has to have a time delay to allow the breaker at the remote station to clear a fault on another line. The third zone reaches beyond the remote second zones and so has to time coordinate in the same manner, thus the increasing time settings.

Coordinating with overcurrent relays can be more difficult and can also require a more detailed knowledge of system parameters.

For the simple system shown in Figure 12-17, with a fault at X, the near relays at C and D has to operate and their breakers have to be completely open before the remote or backup relays at A and F close their contacts. It is assumed that:

1. A faulted condition exists until the breakers isolating the fault are entirely open.

2. When a relay closes its tripping contacts, a "seal-in" auxiliary relay ensures that the switching operation will be completed even though the fault is cleared at the same instant the relay contacts close.
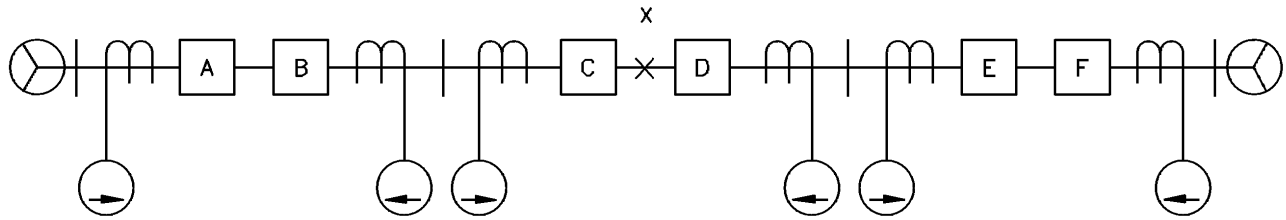
Figure 12-17: Coordination Conditions

The time delay of the remote relay necessary for selectivity has to be equal to the operating time of the near relay plus the opening time of the breaker; plus a reasonable factor of safety, which can be taken at about 25 percent of the combined relay and breaker time with a minimum allowance of not less than six cycles if the relays are normally field calibrated at the calculated setting. If the relays are bench tested at typical setting values and only adjusted in the field with no further calibration, this margin has to be greater, typically 0.2 to 0.3 seconds.

Additional requirements for adequate relay coordination include the following:

1.   The relays have to be capable of carrying a reasonable emergency overload without tripping incorrectly on load current.

2.   The relays have to be able to operate under minimum system generating conditions for faults at the far ends of the sections that they protect.

Maximum system generating conditions include a sufficient number of generators in service to supply the maximum demand load of the system. Similarly, the minimum system generating conditions include only the generators in service necessary to supply the minimum system load. Such minimum conditions would probably exist early Sunday mornings, for example. In addition to the above generation, there are usually some emergency generators in service called "spinning reserve" that can immediately pick up load if a generator fails. Both maximum and minimum conditions have to be checked, since maximum generation usually results in faster operation of induction-type relays with more critical selectivity, and the minimum condition determines whether the relays will receive sufficient current to operate.

The output of a synchronous generator under fault conditions is variable, depending on the characteristics of the machine and the duration of the fault. The initial output, which is maintained for three cycles or less, may be four to ten times the normal machine rating and is determined by the *subtransient reactance*. The generator output rapidly decreases to the value determined by *transient reactance*, the average value of which may be assumed to exist for about 30 cycles on turbine generators and up to 120 cycles on condensers and slow-speed generators. The transient reactance may be taken roughly as 125 percent to 150 percent of the subtransient reactance. If the fault is not cleared, the generator output approaches the synchronous value, which is equal to or slightly less than the normal rating. It is the common practice, therefore, to use generator subtransient reactance values when calculating maximum fault kVA and to use transient values for minimum generating conditions. Synchronous values of short-circuit kVA are not usually calculated, but the decrease in generator output should be considered for slow operating relays.

For ground current calculations and determination of selectivity for ground relays, it is customary to show only the maximum fault conditions on transmission systems. On transmission systems where the relative distribution of ground fault current is changed for minimum generation because grounded transformers have been removed from service, it may be necessary to calculate and check the relay settings for both maximum and minimum ground faults. It may also be necessary to show minimum ground faults for some special conditions with certain lines or transformer banks out of service.

Briefly summarized, the job of the relay engineer is to assume various types of faults at numerous points on a system. The magnitude and distribution of fault currents are then calculated for these fault points with maximum and minimum generating conditions. Faults are assumed for normal system operating conditions and for various special conditions with certain lines, generators, or transformers out of service.

The operating time of all breakers involved have to be checked and tabulated and, for high burdens or low ratios, the true or effective ratios of bushing-type current transformers have to be determined. Having obtained these data, the next step is to determine suitable settings or adjustments for the relays that will provide selective operation for each fault condition. The tentative relay settings, the calculated current values, and the operating times of the near and remote relays for each fault condition are worked up and recorded as "Details of Selectivity" or on "Selectivity Curves." After the most satisfactory settings are determined, "Summary Sheets" are made up for all the relays at each station. The Summary Sheets have the instructions or calibration data to enable the relay personnel in the field to set or adjust the relays to obtain the desired operating characteristics.

12.5   REFERENCES

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APPENDIX F
STANDARD DEVICE FUNCTION NUMBERS

The following Standard Device Function Numbers are reprinted from IEEE Std. 37.2-1996, "IEEE Standard Electrical Power System Device Numbers and Contact Designations," Copyright © 1996 by the Institute of Electrical and Electronics Engineers, Inc. The IEEE disclaims any responsibility or liability resulting from the placement and use in the described manner. Information is reprinted with the permission of the IEEE.

Device Number	Definition and Function
1	**Master Element** is a device, such as a control switch, etc., that serves, either directly or through such permissive devices as protective and time-delay relays, to place equipment in or out of operation.
	NOTE-This number is normally used for a hand-operated device, although it may also be used for an electrical or mechanical device for which no other function number is suitable.
2	**Time-delay starting or closing relay** is a device that functions to give a desired amount of time delay before or after any point of operations in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62, 79, and 82.
3	**Checking or interlocking relay** is a device that operates in response to the position of one or more other devices or predetermined conditions in a piece of equipment or circuit, to allow an operating sequence to proceed, or to stop, or to provide a check of the position of these devices or conditions for any purpose.
4	**Master contactor** is a device, generally controlled by device function 1 or the equivalent and the required permissive and protective devices, that serves to make and break the necessary control circuits to place equipment into operation under the desired conditions and to take it out of operation under abnormal conditions.
5	**Stopping device** is a control device used primarily to shut down equipment and hold it out of operation. (This device may be manually or electrically actuated, but it excludes the function of electrical lockout [see device function 86] on abnormal conditions.)
6	**Starting circuit breaker** is a device whose principal function is to connect a machine to its source of starting voltage.
7	**Rate-of-change relay** is a device that operates when the rate-of-change of the measured quantity exceeds a threshold value except as defined by device 63 (see 3.1.63).
8	**Control power disconnecting device** is a device, such as a knife switch, circuit breaker, or pull-out fuse block, used for the purpose of connecting and disconnecting the source of control power to and from the control bus or equipment.
	NOTE-Control power is considered to include auxiliary power that supplies such apparatus as small motors and heaters.
9	**Reversing device** is a device that is

Device Number	Definition and Function	Device Number	Definition and Function
	used for the purpose of reversing a machine field or for performing any other reversing function.		equal to, or approximately equal to, that of another machine, source, or system.
10	**Unit sequence switch** is a device that is used to change the sequence in which units may be placed in and out of service in multiple-unit equipment.	16	Reserved for future application.
11	**Multifunction device** is a device that performs three or more comparatively important functions that could only be designated by combining several device function numbers. All of the functions performed by device 11 shall be defined in the drawing legend, device function definition list or relay setting record. See Annex B for further discussion and examples. NOTE-If only two relatively important functions are performed by the device, it is preferred that both function numbers can be used as described in 3.6.	17	**Shunting or discharge switch** is a device that serves to open or close a shunting circuit around any piece of apparatus (except a resistor), such as a machine field, a machine armature, a capacitor, or a reactor. NOTE-This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42 (or their equivalent) and also excludes device function 73 that serves for the switching of resistors.
12	**Overspeed device** is a device, usually direct connected, that operates on machine overspeed.	18	**Accelerating or decelerating device** is a device that is used to close or cause the closing of circuits that are used to increase or decrease the speed of a machine.
13	**Synchronous-speed device** is a device such as a centrifugal-speed switch, a slip frequency relay, a voltage relay, an undercurrent relay, or any other type of device that operates at approximately the synchronous speed of a machine.	19	**Starting-to-running transition contactor** is a device that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.
14	**Underspeed device** is a device that functions when the speed of a machine falls below a predetermined value.	20	**Electrically operated valve** is an electrically operated, controlled, or monitored device used in a fluid, air, gas, or vacuum line. NOTE-The function of the valve may be more completely indicated by the use of suffixes as discussed in 3.2.
15	**Speed or frequency matching device** is a device that functions to match and hold the speed or frequency of a machine or a system		

Device Number	Definition and Function	Device Number	Definition and Function
21	**Distance relay** is a device that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.		magnitude, phase angle, and frequency.
22	**Equalizer circuit breaker** is a device that serves to control or make and break the equalizer or the current-balancing connections for a machine field, or for regulating equipment, in a multiple-unit installation.	26	**Apparatus thermal device** is a device that functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.
23	**Temperature control device** is a device that functions to control the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above a predetermined value. NOTE-An example is a thermostat that switches on a space heater in a switchgear assembly when the temperature falls to a desired value. This should be distinguished from a device that is used to provide automatic temperature regulation between close limits and would be designated as device function 90T.	27	**Undervoltage relay** is a device that operates when its input voltage is less than a predetermined value.
		28	**Flame detector** is a device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.
		29	**Isolating contactor or switch** is a device that is used expressly for disconnecting one circuit from another for the purposes of emergency operation, maintenance, or test.
24	**Volts per hertz relay** is a device that operates when the ratio of voltage to frequency is above a preset value. The relay may have any combination of instantaneous or time delayed characteristics.	30	**Annunciator relay** is a nonautomatically reset device that gives a number of separate visual indications upon the functioning of protective devices and that may also be arranged to perform a lockout function.
25	**Synchronizing or synchronism-check relay** is a synchronizing device that produces an output that causes closure at zero-phase angle difference between two circuits. It may or may not include voltage and speed control. A synchronism-check relay permits the paralleling of two circuits that are within prescribed limits of voltage	31	**Separate excitation device** is a device that connects a circuit, such as the shunt field of a synchronous

Device Number	Definition and Function	Device Number	Definition and Function
	converter, to a source of separate excitation during the starting sequence.	38	**Bearing protective device** is a device that functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing, such as undue wear, which may eventually result in excessive bearing temperature or failure.
32	**Directional power relay** is a device that operates on a predetermined value of power flow in a given direction such as reverse power flow resulting from the motoring of a generator upon loss of its prime mover.	39	**Mechanical condition monitor** is a device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38), such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.
33	**Position switch** is a device that makes or breaks contact when the main device or piece of apparatus that has no device function number reaches a given position.		
34	**Master sequence device** is a device such as a motor-operated multi-contact switch, or the equivalent, or a programmable device, that establishes or determines the operating sequence of the major devices in equipment during starting and stopping or during sequential switching operations.	40	**Field relay** is a device that functions on a given or abnormally high or low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an ac machine indicating abnormally high or low field excitation.
35	**Brush-operating or slip-ring short-circuiting device** is a device for raising, lowering, or shifting the brushes of a machine; short-circuiting its slip rings; or engaging or disengaging the contacts of a mechanical rectifier.	41	**Field circuit breaker** is a device that functions to apply or remove the field excitation of a machine.
36	**Polarity or polarizing voltage device** is a device that operates, or permits the operation of, another device on a predetermined polarity only or that verifies the presence of a polarizing voltage in equipment.	42	**Running circuit breaker** is a device whose function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault-protecting means, primarily for
37	**Undercurrent or underpower relay** is a device that functions when the current or power flow decreases below a predetermined value.		

Device Number	Definition and Function	Device Number	Definition and Function
	frequent opening and closing of the circuit.		normal starting, operating, or stopping sequence is not properly completed within a predetermined time.
43	**Manual transfer or selector device** is a manually operated device that transfers control or potential circuits in order to modify the plan of operation of the associated equipment or of some of the associated devices.	49	**Machine or transformer thermal relay** is a device that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.
44	**Unit sequence starting relay** is a device that functions to start the next available unit in multiple-unit equipment upon the failure or non-availability of the normally preceding unit.	50	**Instantaneous overcurrent relay** is a device that operates with no intentional time delay when the current exceeds a preset value.
45	**Atmospheric condition monitor** is a device that functions upon the occurrence of an abnormal atmospheric condition, such as damaging fumes, explosive mixtures, smoke, or fire.	51	**AC time overcurrent relay** is a device that functions when the ac input current exceeds a predetermined value, and in which the input current and operating time are inversely related through a substantial portion of the performance range.
46	**Reverse-phase or phase-balance current relay** is a device in a polyphase circuit that operates when the polyphase currents are of reverse-phase sequence or when the polyphase currents are unbalanced or when the negative phase-sequence current exceeds a preset value.	52	**AC circuit breaker** is a device that is used to close and interrupt an ac power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.
47	**Phase-sequence or phase-balance voltage relay** is a device in a polyphase circuit that functions upon a predetermined value of polyphase voltage in the desired phase sequence, when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a preset value.	53	**Exciter or dc generator relay** is a device that forces the dc machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.
48	**Incomplete sequence relay** is a device that generally returns the equipment to the normal or off position and locks it out if the		

Device Number	Definition and Function	Device Number	Definition and Function
54	**Turning gear engaging device** is a device either electrically operated, controlled, or monitored that functions to cause the turning gear to engage (or disengage) the machine shaft	63	**Pressure switch** is a device that operates at a given pressure value or at a given rate of change of pressure.
55	**Power factor relay** is a device that operates when the power factor in an ac circuit rises above or falls below a predetermined value.	64	**Ground detector relay** is a device that operates upon failure of machine or other apparatus insulation to ground.
56	**Field application relay** is a device that automatically controls the application of the field excitation to an ac motor at some predetermined point in the slip cycle.		NOTE-This function is not applied to a device connected in the secondary circuit of current transformers in a normally grounded power system where other overcurrent device numbers with the suffix G or N should be used; for example, 51N for an ac time overcurrent relay connected in the secondary neutral of the current transformers.
57	**Short-circuiting or grounding device** is a device that functions to short-circuit or ground a circuit in response to automatic or manual means.		
58	**Rectification failure relay** is a device that functions if a power rectifier fails to conduct or block properly.	65	**Governor** is a device consisting of an assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other media to the prime mover for such purposes as starting, holding speed or load, or stopping.
59	**Overvoltage relay** is a device that operates when its input voltage exceeds a predetermined value.		
60	**Voltage or current balance relay** is a device that operates on a given difference in voltage, or current input or output, of two circuits.	66	**Notching or jogging device** is a device that functions to allow only a specified number of operations of a given device or piece or equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit periodically or for fractions of specified time intervals, or that is used to permit intermittent
61	**Density switch or sensor** is a device that operates at a given density value or at a given rate of change of density.		
62	**Time-delay stopping or opening relay** is a device that imposes a time delay in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.		

Device Number	Definition and Function	Device Number	Definition and Function
	acceleration or jogging of a machine at low speeds for mechanical positioning.		of load limiting, shifting, or indicating resistance in a power circuit; to switch a space heater in circuit; or to switch a light or regenerative load resistor of a power rectifier or other machine in and out of circuit.
67	**AC directional overcurrent relay** is a device that functions at a desired value of ac overcurrent flowing in a predetermined direction.	74	**Alarm relay** is a device other than an annunciator, as covered under device function 30, that is used to operate, or that operates in connection with, a visual or audible alarm.
68	**Blocking or "out-of-step" relay** is a device that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or cooperates with other devices to block tripping or reclosing on an out-of-step condition or on power swings.	75	**Position changing mechanism** is a device that is used for moving a main device from one position to another in equipment; for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.
69	**Permissive control device** is a device with two positions that in one position permits the closing of a circuit breaker, or the placing of a piece of equipment into operation, and in the other position, prevents the circuit breaker or the equipment from being operated.	76	**DC overcurrent relay** is a device that functions when the current in a dc circuit exceeds a given value.
70	**Rheostat** is a device used to vary the resistance in an electric circuit when the device is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.	77	**Telemetering device** is a transmitting device used to generate and transmit to a remote location an electrical signal representing a measured quantity; or a receiver used to receive the electrical signal from a remote transmitter and convert the signal to represent the original measured quantity.
71	**Level switch** is a device that operates at a given level value, or on a given rate of change of level.	78	**Phase-angle measuring relay** is a device that functions at a predetermined phase angle between two voltages, between two currents, or between voltage and current.
72	**DC circuit breaker** is a device that is used to close and interrupt a dc power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.		
73	**Load-resistor contactor** is a device that is used to shunt or insert a step		

Device Number	Definition and Function	Device Number	Definition and Function
79	**Reclosing relay** is a device that controls the automatic reclosing and locking out of an ac circuit interrupter.		until it is reset by an operator, either locally or remotely.
80	**Flow switch** is a device that operates at a given flow value, or at a given rate of change of flow.	87	**Differential protective relay** is a device that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electrical quantities.
81	**Frequency relay** is a device that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds or is less than a predetermined value.	88	**Auxiliary motor or motor generator** is a device used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.
82	**DC load-measuring reclosing relay** is a device that controls the automatic closing and reclosing of a dc circuit interrupter, generally in response to load circuit conditions.	89	**Line switch** is a device used as a disconnecting, load-interrupter, or isolating switch in an ac or dc power circuit. (This device function number is normally not necessary unless the switch is electrically operated or has electrical accessories, such as an auxiliary switch, a magnetic lock, etc.)
83	**Automatic selective control or transfer relay** is a device that operates to select automatically between certain sources or conditions in equipment or that performs a transfer operation automatically.	90	**Regulating device** is a device that functions to regulate a quantity or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.
84	**Operating mechanism** is a device consisting of the complete electrical mechanism or servomechanism, including the operating motor, solenoids, position switches, etc., for a tap changer, induction regulator, or any similar piece of apparatus that otherwise has no device function number.	91	**Voltage directional relay** is a device that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.
85	**Carrier or pilot-wire relay** is a device that is operated or restrained by a signal transmitted or received via any communications media used for relaying.	92	**Voltage and power directional relay** is a device that permits or
86	**Lockout relay** is a device that trips and maintains the associated equipment or devices inoperative		

Device Number	Definition and Function	Device Number	Definition and Function
	causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.	94	**Tripping or trip-free relay** is a device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.
93	**Field-changing contactor** is a device that functions to increase or decrease, in one step, the value of field excitation on a machine.	95-99	These device numbers are used in individual specific installations if none of the functions assigned to the numbers 1 through 94 are suitable.

APPENDIX G
SUGGESTED SUFFIX LETTERS

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Auxiliary devices
These letters denote separate auxiliary devices, such as the following:

C   Closing relay/contactor
CL   Auxiliary relay, close (energized when main device is in closed position)
CS   Control switch
D   "Down" position switch relay
L   Lowering relay
O   Opening relay/contactor
OP   Auxiliary relay, open (energized when main device is in open position)
PB   Push button
R   Raising relay
U   "UP" position switch relay
X   Auxiliary relay
Y   Auxiliary relay
Z   Auxiliary relay

NOTE-In the control of a circuit breaker with a so-called X-Y relay control scheme, the X relay is the device whose main contacts are used to energize the closing coil or the device that in some other manner, such as by the release of stored energy, causes the breaker to close. The contacts of the Y relay provide the antipump feature of the circuit breaker.

Actuating quantities
These letters indicate the condition or electrical quantity to which the device responds, or the medium in which it is located, such as the following:

A   Air/amperes/alternating
C   Current
D   Direct/discharge
E   Electrolyte
F   Frequency/flow/fault
GP   Gas pressure
H   Explosive/harmonics
I0   Zero sequence current
I–, I2 Negative sequence current
I+, I1 Positive sequence current
J   Differential
L   Level/liquid
P   Power/pressure
PF   Power factor
O   Oil
S   Speed/suction/smoke
T   Temperature

V   Voltage/volts/vacuum
VAR   Reactive power
VB   Vibration
W   Water/watts

Main device
The following letters denote the main device to which the numbered device is applied or is related:
A   Alarm/auxiliary power
AC   Alternating current
AN   Anode
B   Battery/blower/bus
BK   Brake
BL   Block (valve)
BP   Bypass
BT   Bus tie
C   Capacitor/condenser/compensator/carrier current/case/compressor
CA   Cathode
CH   Check (valve)
D   Discharge (valve)
DC   Direct current
E   Exciter
F   Feeder/field/filament/filter/fan
G   Generator/ground[1]
H   Heater/housing
L   Line/logic
M   Motor/metering
MOC   Mechanism operated contact[2]
N   Network/neutral[3]
P   Pump/phase comparison
R   Reactor/rectifier/room
S   Synchronizing/secondary/strainer/sump/suction (valve)
T   Transformer/thyratron
TH   Transformer (high-voltage side)
TL   Transformer (low-voltage side)
TM   Telemeter
TOC   Truck-operated contacts[4]
TT   Transformer (tertiary-voltage side)
U   Unit

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[1] Suffix N is preferred when the device is connected in the residual of a polyphase circuit, is connected across a broken delta, or is internally derived from the polyphase current or voltage quantities. The suffix G is preferred where the measured quantity is in the path to ground or, in the case of ground fault detectors, is the current flowing to ground. See A.2 in Annex A for examples.
[2] MOC denotes a circuit breaker mechanism-operated auxiliary switch that is mounted on the stationary housing of a removable circuit breaker.
[3] See Footnote 1.
[4] TOC denotes a circuit breaker truck-operated auxiliary switch that is mounted on the stationary housing of a removable circuit breaker.

Main device parts
These letters denote parts of the main device, except auxiliary contacts, position switches, limit switches, and torque limit switches.

BK   Brake
C   Coil/condenser/capacitor
CC   Closing coil/closing contactor
HC   Holding coil
M   Operating motor
MF   Fly-ball motor
ML   Load-limit motor
MS   Speed adjusting or synchronizing motor
OC   Opening contactor
S   Solenoid
SI   Seal-in
T   Target
TC   Trip coil
V   Valve

Other suffix letters
The following letters cover all other distinguishing features, characteristics, or conditions not specifically described in Suggested Suffix Letters, which serve to describe the use of the device in the equipment, such as

A   Accelerating/automatic
B   Blocking/backup
BF   Breaker failure
C   Close/cold
D   Decelerating/detonate/down/disengaged
E   Emergency/engaged
F   Failure/forward
GP   General purpose
H   Hot/high
HIZ   High impedance fault
HR   Hand reset
HS   High speed
L   Left/local/low/lower/leading
M   Manual
O   Open/over
OFF   Off
ON   On
P   Polarizing
R   Right/raise/reclosing/receiving/remote/reverse
S   Sending/swing
SHS   Semi-high speed
T   Test/trip/trailing

TDC   Time-delay closing contact
TDDO Time delayed relay coil drop-out
TDO   Time-delay opening contact
TDPU Time delayed relay coil pickup
THD   Total harmonic distortion
U   Up/under

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CHAPTER 13
INSTRUMENTS, TRANSDUCERS, AND METERS

13.1   INTRODUCTION

Substations employ many different systems to monitor operations. Depending on equipment types and configurations, a large variety of instruments, transducers, and meters may be used to perform this function.

13.2   INSTRUMENTS AND TRANSDUCERS

13.2.1   Definitions

An instrument is a device for sensing the magnitude of a physical quantity. It is calibrated or programmed to indicate or record this magnitude based on a known standard. The instrument may be indicating or recording. A transducer is a device that converts a physical quantity to a proportional low-level dc signal. Electrical transducers typically change amperes, watts, volts, and VARs to millivolt or milliampere signals. Transducer outputs can be used to operate local instruments or can be employed in data acquisition systems.

13.2.1.1   Indicating Instruments: An indicating instrument depicts the present value of the quantity measured by the position of a pointer relative to a scale or as a digital display. It is used to give an observer information regarding the present operation of equipment or circuits.

13.2.1.2   Recording (Graphic) Instruments: A recording or graphic instrument makes graphic records of the value of a quantity as a function of time. This type of instrument is used when a permanent record of how the measured quantity varies with time is needed.

13.2.2   Types of Instruments and Transducers

Instruments (indicating and recording) and transducers may be grouped according to the quantity they measure. The specific quantity is generally used with the suffix "meter" to identify the instrument. Thus, an ammeter is an instrument that measures amperes, a voltmeter is an instrument that measures voltages, etc. The most commonly used instruments for measurements of electrical quantities are ammeter, voltmeter, wattmeter, varmeter, frequency meter, and ohmmeter.

13.2.3   Classification of Instruments

13.2.3.1   Switchboard or Panel Instruments: Switchboard instruments are intended for fixed installation on switchboards, panels, or consoles. Since they are constructed for fixed installations, they require careful handling in transport. Panel instruments are similar to switchboard instruments, but are used where smaller scale instruments are satisfactory.

13.2.4   Components of Instruments and Transducers

13.2.4.1   Analog Indicating Instruments: The components of analog indicating instruments are mechanism, scale, base, and cover. The mechanism is an arrangement of parts for producing and control-ling the motion of the indicating hand or pointer. The mechanism for electromagnetic instruments

includes the moving element, magnetic structure, control spring, and instrument hand or pointer. The components of thermal instruments are the same as those for electromagnetic instruments except the mechanism consists of the moving element, bimetallic strip, heater, adjusting spring, and instrument hand or pointer.

13.2.4.2   Digital Indicating Instruments: These instruments are completely solid state and either contain a transducer or require inputs in the form of dc millivolt signals from transducers. The instruments then condition the signals to eliminate noise bursts and surges, feed the conditioned signals to analog to digital converters followed by binary-to-decimal encoders, and display the quantities on gaseous discharge or light-emitting diode displays. Internal "clocks" (usually 1 kHz oscillators) update the displays every millisecond. In addition to the digital display, these instruments may also have communications circuitry to permit remote monitoring of the measured quantities.

13.2.4.3   Recording Instruments: These instruments are similar to digital indicating instruments but have the additional capability of data storage. Recording instruments employ electronic memory to store measured values recorded over a specified period. The stored data may be retrieved at a later date for further review and study. Various forms of communication including telephone circuit, microwave radio, and fiber-optic network may be used to retrieve data stored by the recording instrument. In some cases, the recording instrument may be connected to a local printer. The local printer is used to produce a paper copy of the stored data in table or graphical form.

13.2.5   Analog Instrument Scales

The instrument scale depicts the numerical value of the quantity being measured as indicated by the position of the hand or pointer with respect to scale markings. Convenient scales will give more accurate information and lessen observer eye strain. There are two basic types of instrument scales: linear scale and nonlinear scale.

13.2.5.1   Linear Scale: This scale is divided into a number of equally spaced segments, each segment representing the same unit of measurement. This type of scale is used when there are wide variations in the magnitude of the measured quantity. Figure 13-1 shows two analog switchboard voltmeters with linear scales.
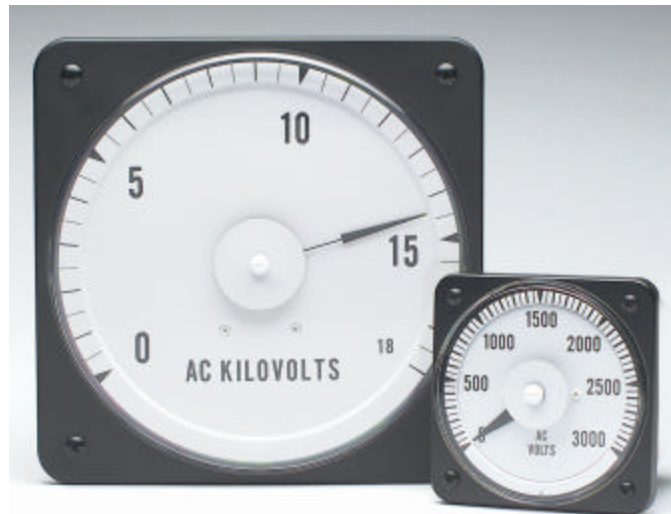
Figure 13-1: Linear Scale Analog Switchboard Voltmeters. Courtesy of Yokogawa.

13.2.5.2   Nonlinear Scale: This scale is divided into a number of unequally spaced segments. Each segment may or may not represent the same unit of measurement. Usually the segments are expanded at one end of the scale and compressed at the other end of the scale. This type of scale is used when variations of the measured quantity are small and usually fall in the expanded area of the scale, thus permitting more accurate readings. Figure 13-2 shows an analog switchboard power factor meter with a nonlinear scale.

Figure 13-2: Nonlinear Scale Power Factor Meter. Courtesy of Yokogawa.

13.2.6   Operating Procedures

Instruments furnish valuable and indispensable information on the performance of an electric system or device. Without this information, the operator would be almost completely uninformed and would have to depend upon some crude or often inaccurate observations. Any abnormal indication should be immediately investigated.

13.2.6.1   Reading Instrument Scales: The best instrument will serve no purpose unless properly read and correctly interpreted. Good lighting is essential to accurate reading; glare as a result of reflection of concentrated light should be avoided. Newer instruments have special covers to reduce glare. Some instruments are direct reading in that the scales directly furnish the values of the measured quantities, whereas other instruments require the use of instrument constants called scale factors. In this latter case the actual measured quantity is obtained by multiplying the instrument indication as shown on the scale by the scale factor. The scale factor may be shown on the instrument or may be associated with the position of an instrument switch. In the latter case, each position of the instrument switch will represent a different scale factor.

EXAMPLE 13-1: An ac ammeter with 0 to 5 ampere scale and 50 divisions has its indicating pointer located on the 35 division point. The scale factor is 20 as shown on the ammeter switch. The measured value is:

$$\frac{\text{Instrument Reading } x \text{ Scale}}{\text{Total Divisions}} \; x \text{ Scale Factor} = \frac{35 \; x \; 5}{50} \; x \; 20 \; = 70 \text{ Amperes}$$

13.2.6.2   Care of Instruments: Instruments can withstand a certain amount of abuse such as occasionally going off scale for momentary periods, but sustained overloads to the meter will damage the mechanism or pointer. Instrument covers should be tightly fastened to the case to prevent entrance of dust or fumes. Instruments should not be left for extended periods without covers.

13.2.6.2.1   Switchboard Instruments: These instruments are rather rugged devices, but should be protected from excessive vibration and shock. The instruments should be kept clean to facilitate reading of the measured quantity.

13.2.6.2.2   Recording Instruments: Recording instruments require additional care if they contain printers or floppy disk drives. The instrument should be located in a dry place and kept clean. Printers should be checked periodically to ensure they have a sufficient paper supply and are printing legibly. Disks placed in disk drives should be monitored for sufficient storage space. It may be necessary to replace the disk periodically, depending on the amount of information being stored.

13.3   METERS

13.3.1   Definition

An electric meter is a device that measures and registers the integral of an electrical quantity with respect to time. The term "meter" is also used in a general sense to designate any type of measuring device including all types of electrical measuring instruments. Use of "meter" as a suffix to a compound word (e.g., voltmeter, ammeter, frequency meter) is universally accepted. However, in this chapter the narrow meaning of "electric meter" is used.

13.3.2   Types of Electric Meters

The most common types of electric meters are watt-hour meter, VAR-hour meter, and ampere-hour meter.

13.3.2.1   Watt-Hour Meter: The watt-hour meter is an electric meter that measures and registers electric energy in watthours or kilowatt-hours (1,000 watt-hours).

EXAMPLE 13-2: If the active electric power of a circuit is 15 kW and is consumed at a uniform rate for 3 hours, the watt-hour meter will register 3 x 15 = 45 kWh.

13.3.2.2   VAR-Hour Meter: A VAR-hour meter is an electric meter that measures and registers reactive power in reactive volt-ampere-hours (or reactive kilovolt-ampere-hours).

13.3.2.3   Ampere-Hour Meter: An ampere-hour meter is an electric meter that registers the quantity of electricity in ampere-hours.

13.3.3   Demand Meter

A demand meter is a device that indicates or records the maximum average load over any specified time interval (usually one hour or less) or the average load over a number of equal time intervals. It is a special form of electric meter indicating or recording the measured load for a given time interval and then resetting.

13.3.4 Combination Watt-Hour and Demand Meters

These meters measure and register load and also indicate or record maximum demand.

EXAMPLE 13-3: If the active electric power in a circuit at the beginning of the measuring period is 20 kW and is uniformly decreasing until it reaches 10 kW at the end of 1 hour and then continues at the same uniform rate of 10 kW for 2 more hours, the watt-hour meter will read 35 kWh at the end of the third hour, and the demand meter will read a maximum 1-hour demand of 15 kW.

13.3.5 Types of Meter Indicating and Recording Devices

Each meter has a device that records the measured quantity. An electric meter usually has a register, which registers the integrating load. The demand meter has an indicating, graphic (recording), printing, or digital device. Digital device meters may also have communications circuitry to permit remote monitoring of the measured quantities.

13.3.5.1 Electric Meter Registers and Register Constants: The registers are the prime concern of the operators since the registers furnish the magnitude of electrical energy consumed by the load.

13.3.5.1.1 Register: The meter register may be dial (pointer) type or cyclometric (digital) type. In the dial-type register, four or five dials are used to show the quantity measured. The register reads from left to right with the highest reading on the four-dial register 9999 and on the five-dial register 99999. The cyclometric register usually consists of four numbered rotating discs with the applicable number on each disc visible through a slot on a plate in front of the register.

13.3.5.1.2 Register Constant: The register or dial constant of a meter is the multiplier used to convert the register reading to the actual measured value. Its value may be 1, 10, or any multiple of 10. Another constant, used with watt-hour meters, is the watt-hour constant, which is the registration of one revolution of the meter disc expressed in watt-hours. This constant is used only when calibrating watt-hour meters, but can be used to calculate the register constant. The register constant is usually marked on the meter register, and the watt-hour constant is shown on the meter nameplate.

13.3.5.1.3 Electronic Register: Many modern electric meters have electronic registers. The electronic register displays the quantity measured on a liquid crystal display (LCD) or other electronic screen. Typically the units of the measured quantity are also displayed. No multiplier is required to convert the displayed value to the actual measured value.

13.3.5.2 Indicating Demand Meter: This meter has a sweep hand to indicate the maximum demand for any given period. This period might be 15, 30, or 60 minutes. The maximum demand indicating hand is generally reset every month when the watt-hour meter reading is obtained.

13.3.5.3 Recording Demand Meter: This meter may be found in existing installations but is generally not specified for new construction. The recording meter records the demand for each given demand period on either a round or strip chart. This chart, therefore, indicates all the demands over a given period. The maximum demand is determined by inspection of the meter chart.

13.3.5.4 Contact Device: This was originally a pair of contacts on a cam geared to the rotating disc shaft of the watt-hour meter to produce a series of pulses. The pulse rate was directly proportional to the speed at which the meter disc rotated. On more recent analog types, a second slotted disc geared to the

meter shaft passes between a photocell and a light source. The resultant voltage pulse train produced is amplified and applied to a reed relay to produce a contact pulse output.

13.3.5.5   Totalizer: This solid-state device receives pulse trains from several watt-hour meters and produces a single output pulse train proportional to the sum of the inputs. Inputs may be additive or subtractive.

13.3.5.6   Demand Meter Constant: The constant of a demand meter is the multiplier used to convert the indicated or recorded demand reading on the meter to actual measured values. This constant may be 1, 10, or a multiple of 10. The demand meter constant and the register constant on the watt-hour meter do not necessarily have the same value.

13.3.5.7   Digital Memory: Electronic meters typically have digital memory that will retain measured values for a defined period. The values may be stored in random access memory (RAM) or on a magnetic medium such as a tape drive, hard drive, or floppy disk. The values stored in digital memory can be read by a computer connected to the digital memory device via local connection or through a communications link.

13.3.6   Connection of Watt-Hour and VAR-Hour Meters

Watt-hour and VAR-hour meters have to have both current and potential connections to measure the active and reactive energy. Watt-hour and VAR-hour meters are classified with respect to circuit connections and the type of load being measured.

13.3.6.1   Self-Contained Watt-Hour and VAR-Hour Meters: The current and potential coils of self-contained meters are connected directly to the circuit. These meters are normally used where the circuit voltage does not exceed 240 volts and the continuous load does not exceed 30 amperes. Self-contained watt-hour meters for 200- and even 400-ampere continuous load currents and 480 volts circuit voltage are available but are usually only used in special cases.

13.3.6.2   Transformer-Type Meters: The current and potential coils of transformer-type meters are connected to the circuit by means of current and potential transformers. These meters are normally used when the circuit voltage exceeds 240 volts and/or the current is above 200 amperes. Current transformers are used to reduce the current to the meter to 5 amperes at rated load. Potential transformers are used to reduce the voltage to the meter to 120 volts.

13.3.6.3   Single-Phase Watt-Hour Meter: Both self-contained and transformer-type meters may be used for single-phase systems. These meters have only one current and one potential coil. The transformer-type meter is usually equipped with a small indicating lamp to show when the potential coil is energized. This is important where the secondary of the potential transformer is fused.

13.3.6.4   Three-Phase, Two-Element Watt-Hour Meter: These meters have two current and two potential coils and are used on three-phase, three-wire systems. Transformer-type meters require two current transformers and two potential transformers. The meters often have two small indicating lamps to show when the two potential coils of the watt-hour meter are energized.

13.3.6.5   Three-Phase, Two and a Half-Element Watt-Hour Meter: These meters have three current coils and two potential coils and are used on three-phase, four-wire systems where the error due to voltage unbalances on the three-phase system can be neglected. Transformer-type meters require three

current transformers and two potential transformers. There are two potential indicating lamps to show when the two potential coils are energized.

13.3.6.6   Three-Phase, Three-Element Watt-Hour Meter: These meters have three current coils and three potential coils and are used on three-phase, four-wire systems where both current and voltage unbalances can be expected. Transformer-type meters require three potential transformers and three current transformers. There are three potential indicating lamps to show when the three potential coils are energized.

13.4   MULTI-FUNCTION METERS

13.4.1   <u>Definition</u>

A multi-function meter is a combination device that performs the functions of instruments, transducers, and meters. It is flexible, allowing the user to monitor many quantities simultaneously. It contains a central processing unit (CPU) for the calculation and digital display of desired quantities. Most multi-function meters can be user configured to normally display a few quantities simultaneously while all quantities can be read using push buttons on the front of the device or via remote monitoring. Many multi-function meters also have digital memory for storing measured quantities recorded over a defined period. Stored quantities can be downloaded to a laptop computer or other digital device. Figure 13-3 shows a multi-function meter.

Figure 13-3: Multi-Function Meter. Courtesy of Bitronics.

13.4.2   Input Quantities

Multi-function meters require three voltage and three current inputs to monitor three-phase power circuits. Because the multi-function meter is a microprocessor-based device, it can be set to calculate primary voltage and primary current values based on inputs from potential and current transformers with a wide range of primary-to-secondary ratios. The instrument transformer ratios are set at the factory but may be changed in the field. Once the instrument transformer ratios are set, the meter will calculate and display primary values with correct units. No scale factors are required to accurately read the meter display.

13.4.3   Measured and Calculated Values

Multi-function meters can measure and calculate many electrical quantities including instantaneous volts, amps, watts, VARs, volt-amperes, power factor, and hertz. The meter may also record the instantaneous maximum and minimum for each of these values over a pre-defined period. Accumulating quantities that can be calculated include watt-hours and VAR-hours. The latest versions of multifunction meters are incorporating programmable alarm levels and various power quality measurements. The meter can also initiate communications to a remote master or PC when certain events or levels are measured.

13.4.4   Communications

Multi-function meters may communicate with remote terminal units (RTUs), programmable logic controllers (PLCs), human–machine interfaces (HMIs), and other digital devices via local communications network, common telephone lines, radio, or carrier signals coupled to power circuits. Local network hardware typically conforms with either RS-232 or RS-485 standards. Additional hardware and software requirements are defined by the communications protocol specified for the local communications network. Telephone lines, radio, and carrier signals are often used by utilities for remote meter reading. (See CRN's *Guide to Automatic Meter Reading: A Tutorial*, Project 98-06.)

13.5   REFERENCES

ANSI Std. C12, "Code for Electricity Metering."

ANSI Std. C39.1, "Requirements for Electrical Analog Indicating Instruments."

CHAPTER 14
SUBSTATION AUTOMATION

14.1   INTRODUCTION

Substation automation is the use of state-of-the-art computers, communications, and networking equipment to optimize substation operations and to facilitate remote monitoring and control of substations cost-effectively. Substation automation uses intelligent electronic devices in the substation to provide enhanced integrated and coordinated monitoring and control capabilities. Substation automation may include traditional SCADA equipment, but more often encompasses traditional SCADA functionality while providing extended monitoring and control capabilities through the use of non-traditional system elements.

In the traditional SCADA system (legacy system), a host computer system (master station) located at the energy control center communicates with remote terminal units located in the substations. RTUs are traditionally "dumb" (non-intelligent) devices with very limited or no capability to perform local unsupervised control. Control decisions are processed in the master station and then carried out by the RTU through the use of discrete electromechanical control relays in the RTU. Analog telemetry information (watts, VARs, volts, amps, etc.) is generated by discrete transducers whose outputs are wired into the RTU. Device status (breaker position, load tap changer position, etc.) is monitored by the RTU through sensing of discrete contacts on these devices. Monitored data is multiplexed by the RTU and communicated back to the master station computer in the form of asynchronous serial data.

Substation automation systems do include many of the same basic elements as the legacy SCADA system but with significant enhancements. A central operations computer system generally provides the master station function. Legacy RTUs may be incorporated into the automation scheme, particularly in retrofit situations, but are generally replaced with intelligent programmable RTUs and other IEDs in an integrated LAN. Legacy transducers are replaced by IEDs that provide not only the traditional analog signals, but a number of additional data values that can be useful to operations, engineering, and management personnel. IEDs communicate with RTUs and local processors via a substation LAN with an open communications protocol, thereby eliminating discrete transducer analog signals. Programmable logic controllers (PLCs) may be included, discretely or integrated into the intelligent RTU, to provide closed loop control and control functions, thereby eliminating the need for many electromechanical relays and interlocks.

The integration of IEDs in the substation has been a major challenge for electric utilities and equipment suppliers. The primary obstacle has been the lack of standards for LAN communications protocols, with manufacturers opting for proprietary protocols that require costly interface modules for protocol conversion. Strides have been made in recent years to resolve the protocol standardization problems, and some de facto standards have emerged. The trend will continue toward more vendor-independent substation network environments as these standardization efforts move forward and as the level of standards support improves among IED manufacturers.

14.2   OPEN VS. PROPRIETARY SYSTEMS

All exchange of data among networked computers and devices may be thought of as part of a network architecture, that is, a framework that provides the necessary physical and communications services to facilitate data exchange. Any number of internally consistent architectures can be chosen to permit the desired communications; however, many are proprietary. Proprietary networking solutions can prove to be

highly effective and efficient from a functional standpoint, but they are not compatible with a multivendor environment that many end users now demand.

In a proprietary network, the network vendor is in control of what features are supported within the network. A vendor can decide not to support certain features, support them incompletely, or require the purchase of expensive upgrades to implement those functions. But proprietary networks do have the advantage that the user has access to a single point of contact and responsibility at the system vendor for all network functions, and these networks are generally guaranteed to "plug and play" without the user having to be concerned about architectures and protocols. A cautionary statement for proprietary systems is needed here. If or when the vendor or his product becomes obsolete, ensure someone will handle support services for this network. An escrow account for the source code of the system is a good starting point. This allows future modifications to the system without having to re-engineer the entire system.

In a network based on open products and standards, the user is no longer dependent on a single vendor to provide the functions and features needed or desired. The user also has the advantage of being able to solicit competitive prices among equipment vendors rather than being locked into one source of supply. But in an open environment, the user has to take responsibility for overall network functionality, and has to take care in the selection of protocols and equipment to ensure "plug-and-play" compatibility.

Two widely accepted open system architectures are the International Organization for Standardization (ISO) Open Systems Interconnection (OSI) 7-layer model, and the Transport Control Protocol/Internet Protocol (TCP/IP) model. TCP/IP was originally developed for the ARPAnet, now called the Internet, but has been widely used in local area networks. A more recent development is the Utility Communications Architecture (UCA), which is a family of OSI-compliant protocols developed by EPRI for use in electric utilities. UCA is discussed in greater detail in Section 14.4.6.2, Utility Communications Architecture.

14.3   SUBSTATION AUTOMATION ARCHITECTURE

The basic architecture of a utility automation system can be viewed as a multi-layered stack (Figure 14-1). At the bottom of the stack are the electrical power substation field devices (transformers, breakers, switches, etc.). The top of the stack is the user interface where data and control prerogatives are presented to the end user, which in this case would be a human operator. The intermediate layers may be implemented with discrete elements or subsystems. In some cases, several levels may be combined into one, or even eliminated altogether.

The overall architecture can be viewed as two layers, each made up of several sublayers. The first or lowest layer, the data acquisition and control layer, is made up of substation-resident equipment. The second or highest layer, the utility enterprise, can be viewed as the information infrastructure layer. This bulletin focuses on the substation-resident data acquisition and control layer.

14.4   DATA ACQUISITION AND CONTROL ELEMENTS

Substation automation may take many different forms and levels of sophistication, depending on the philosophy of the implementing utility and the specific application. For instance, a single serial data interface between a SCADA RTU and an electronic recloser would be an example of a relatively simple and limited application. A fully automated substation with digital relays, electronic reclosers, and programmable logic controllers, all sharing a common network with a substation host processor and man–machine interface, would represent a relatively sophisticated application. Figure 14-2 shows the

	USER INTERFACE	APPLICATIONS LAYER
INFORMATION INFRASTRUCTURE LAYER	APPLICATIONS	
	DATA REPOSITORY	PRESENTATION LAYER
	DATA REPOSITORY ←→ SUBSTATION HOST PROCESSOR INTERFACE	TRANSPORT LAYER
DATA ACQUISITION AND CONTROL LAYER	SUBSTATION HOST PROCESSOR	
	SUBSTATION HOST PROCESSOR ←→ IED INTERFACE	
	LAN	DATA LINK LAYER
	IED'S	
	SUBSTATION FIELD EQUIPMENT	DATA LINK LAYER/ PHYSICAL LAYER

Figure 14-1: Substation Automation Architecture

major data acquisition and control elements found in substation automation and their typical relationship to each other and to the corporate data infrastructure.

Regardless of the size and complexity of the network, the basic elements of substation automation are generally those described in the following subsections.

14.4.1 Substation Host Processor

The substation host processor serves the following functions in the substation automation system:

1. It provides local data storage for data acquired from the field devices.

2. It provides a local human–machine interface, allowing a human operator to locally access system data, view system status, and issue system control commands.

3. It can, if necessary, perform logical data processing and closed-loop control algorithms.

4. It serves as a gateway for communications between the substation and the control center (SCADA host).

The substation host processor may be a single computer, such as a PC, or multiple computers in a networked or distributed computing environment. The substation host processor should be based upon
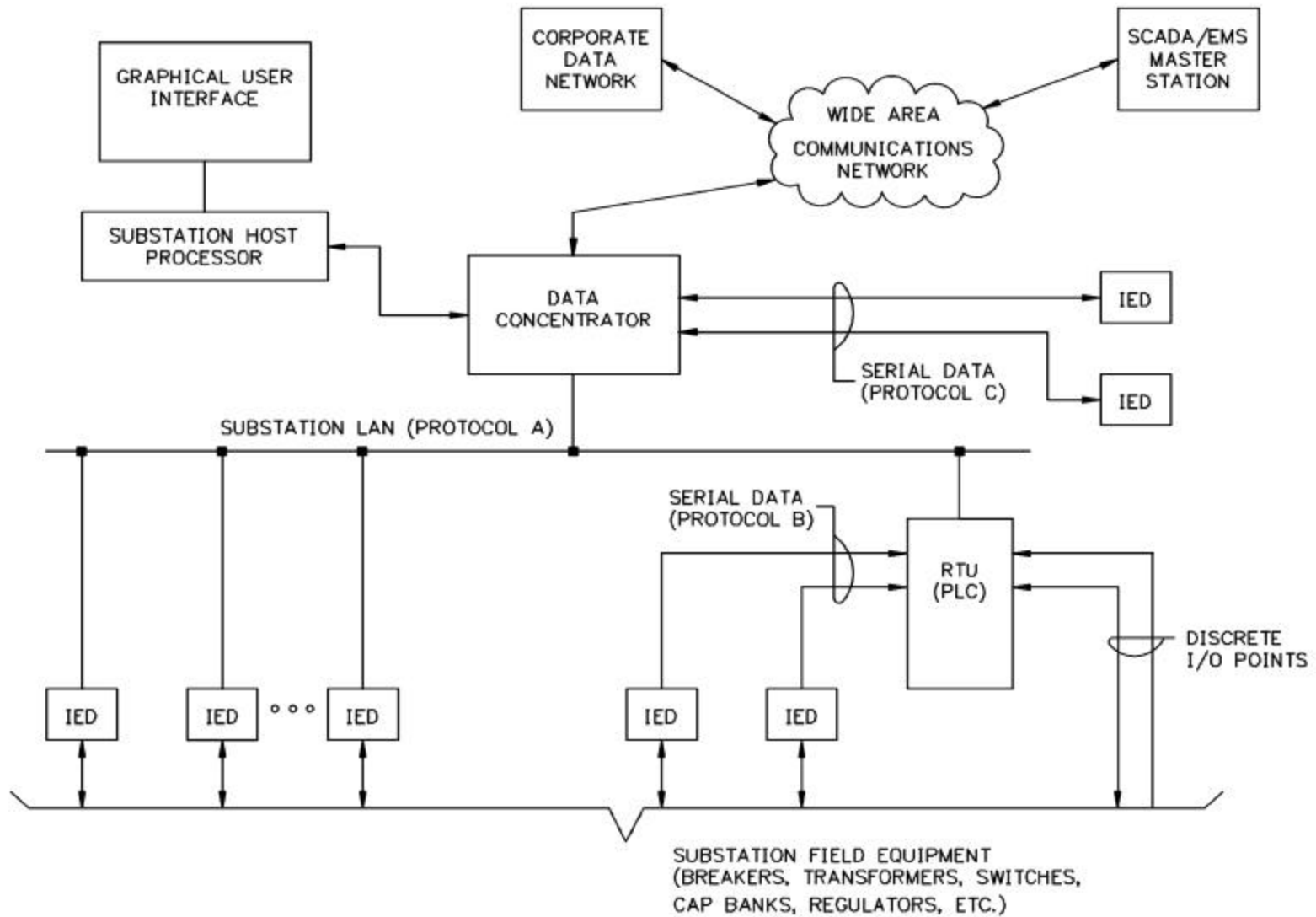
Figure 14-2: Substation Automation Data Acquisition and Control Elements

industry standards and have to have strong networking ability. A Windows-type graphical user interface should be provided.

For smaller substations, a single non-redundant processor should suffice. For larger and more critical substations, a dual-redundant processor with automatic failover is recommended. The level of redundancy called for will vary by application, depending on what functions the host processor is providing, the level of electromechanical backup employed, and the operational risks and implications related to an extended failure of the processor.

14.4.2   <u>Intelligent Electronic Devices</u>

Examples of IEDs are electronic multifunction meters, digital relays, programmable logic controllers (PLCs), digital fault recorders, sequence of events recorders, voltage regulators, capacitor bank controllers, and electronic reclosers. Intelligent SCADA RTUs and PLCs can also be considered IEDs but are typically categorized separately.

Many IEDs perform two functions within the substation. First, the IED provides its primary design function such as relaying, capacitor control, or voltage regulation. But by virtue of the fact that many of these IEDs have built-in instrument transformers, or are otherwise connected to the potential transformer (PT) and/or current transformers (CT) circuits of the substation, the IEDs also calculate and provide a large amount of power system data.

Data available from IEDs includes but is not necessarily limited to the following information:

1.   Power flows (kilowatts, kilovars, power factor, phase angle, kilowatt-hours, kilovar-hours)
2.   Other electrical data values (amperes, volts, symmetrical components)
3.   Fault current (per phase, ground, waveform capture)
4.   Relaying targets
5.   Sequence of events
6.   Oscilliography

Data is retrieved from the IED by the substation host processor and/or a local RTU digitally via a serial data port or other network interface. This eliminates the need for discrete analog tranducers, accomplishing a significant reduction in space and wiring, which can also lead to cost reductions, particularly on new (as opposed to retrofitted) substations.

A single IED can often deliver hundreds of data values even though the utility user is only interested in a small subset of the total data set. The ability to filter the data reported by the IED has been limited as a result of both hardware and protocol-related issues. The goal is to provide the capability to filter or "mask" certain data registers at the IED level, as opposed to making this function protocol or host-dependent.

IEDs should be individually addressable, preventing the need for a dedicated communications channel for each IED. IEDs should support open protocols such as DNP 3.0, ModBus, ASCII, UCA 2.0, IEC 870-5-101 or 103, or TCP/IP (see Section 14.4.6, Communication Protocols).

An important design consideration in development of IED interfaces is the data acquisition method. For example, the IEDs may be polled by the host device for changes (report by exception), or the IEDs may be sequentially scanned (full data dump). In the more common instance of a full scan, it is important to quantify any limitations on the maximum allowable latency of the data (the time required for changes to appear in the

host processor or data repository). These issues may play a role in the selection of IEDs and/or the communication protocol and method.

14.4.3 <u>Programmable Logic Controllers</u>

PLCs may be considered IEDs, but are often considered as a separate class of device. Most IEDs are designed to provide a primary function, such as reclosing, voltage regulation, relaying, or revenue metering, while also offering ancillary system data that has some additional benefit to the utility. PLCs, on the other hand, are more generic and can perform a wide variety of automation functions on a user-programmable basis.

PLCs have traditionally been used in industrial applications such as assembly line automation. PLCs have also been widely used in power generating station distributed control systems, but have only recently been applied in electric utility substations. One of the reasons for the lack of penetration by PLCs into the substation data acquisition and control industry was that PLCs have only recently begun to be manufactured to rigorous substation environmental and electrical standards, such as ANSI Std. C37.90a surge withstand capability. Another recent development is that, with the advent of faster microprocessors, PLCs can now perform sophisticated control procedures fast enough to meet the requirements of substation protective relaying.

PLCs are now finding applications in substations that were traditionally the realm of legacy SCADA RTUs. PLCs can provide the same monitoring and supervisory control functions as an RTU. But PLCs offer the advantages of lower costs than RTUs in some configurations, and ladder logic programmability not available in the legacy RTUs. In an attempt to combat the influx of PLC products into their traditional markets, RTU manufacturers have begun to offer lower cost RTUs with intelligent programmable features. The increased intelligence and programmability of the RTU compared with the PLC's same features should make the defining border between the two obsolete.

In addition to providing traditional SCADA functions, PLCs are being used by utilities for a wide variety of automation functions:

1. Reclosing
2. Auto-sectionalizing
3. Power line carrier automatic check-back schemes
4. Transformer LTC control
5. Capacitor controller
6. Local HMI for alarm annunciator, metering indication, data logging, and events recording
7. Breaker control, especially for more complex operations such as tie breakers
8. Breaker tripping for more complex schemes requiring a significant number of inputs

The programmability of PLCs lends to the development of schemes that were previously considered very difficult to actuate. If the input can be obtained, the ladder logic to make decisions regarding the input can be written to produce an output. Future additions to the substation may also be made simpler since the substation wiring is made easier and logic may be readily changed with the use of PLCs.

Some utilities, because of the complexity of their control schemes, have used PLCs as a control device between relays and breakers to provide tripping and closing of the breakers. While this is not generally recommended, the use of PLCs minimizes installation time because of reduced wiring and control checkout since the logic for any scheme may be entered into the ladder logic.

14.4.4   Data Concentrator

Data concentrators are often the sole communications integration point within the substation. The data concentration function is primarily the integration of multiple incompatible IED protocols for presentation to an external host under a single unified protocol.

The role of the data concentrator is changing with the advent of UCA (see Section 14.4.6.2, Utility Communications Architecture). UCA will allow for direct communications to all IEDs, regardless of whether the communication is internal or external to the substation. But data concentrators may still be desirable for bandwidth efficiency in low-bandwidth wide area telecommunications links.

14.4.5   Substation Local Area Network

The substation LAN provides a means of physical data transfer between intelligent devices in the substation. There are two main distinctions between various LAN types: access method and physical media. The access method, physical media, and transmission rate of the network in megabits per second (Mbps) will also dictate the maximum distance between communicating devices (nodes).

14.4.5.1   Physical Media: The physical media used in LANs include coaxial cable, UTP (unshielded twisted-pair) copper, and optical fiber.

Optical fiber, because of its immunity to electrical effects, has distinct advantages in an electrical substation environment. Coaxial cables and UTP can experience loss or corruption of data messages as a result of electrical transients. Even though protocols at various layers can mitigate some of these adverse effects, it is recommended that fiber-optic media be used to connect all IEDs engaged in protection functions.

14.4.5.2   Access Method: The access method can take various forms. The most common methods are carrier sense multiple access with collision detection (CSMA/CD), token ring, and token bus, and the Fiber Distributed Data Interface (FDDI), although a number of vendor-proprietary schemes are also in use. In selecting an access method, the designer has to consider the expected loading of the network, whether or not a deterministic access method (see below) is required, desired data rate, and the physical distances between nodes or communicating devices.

Networks that use CSMA/CD are generally referred to as Ethernet networks, although this is not always true. Ethernet is actually a proprietary access method developed by Digital Equipment Corporation, but was the basis for the IEEE 802.3 networking standards. CSMA/CD is a broadcast access method where multiple devices contend for access to the same communications medium in a bus architecture. It is a non-deterministic method, meaning that the amount of time required for a message to be sent and received cannot be accurately determined, and is best applied in lightly loaded networks. Its non-deterministic behavior is a disadvantage for time-critical automation tasks like closed-loop control. CSMA/CD is supported under UCA 2.0.

Token ring (IEEE Std. 802.5) is the most commonly used token passing access method. Unlike CSMA/CD, this method is deterministic because token passing among communicating devices is used to govern access to the communications medium. Token ring is supported under UCA 2.0.

Token bus (IEEE Std. 802.4) is a bus access method like CSMA/CD, but uses a token passing arrangement for deterministic medium access. Token bus, like token ring, is supported under UCA 2.0, but is less commonly used than token ring or CSMA/CD.

The Fiber Distributed Data Interface is described in ANSI Std. X3T12 and is supported within UCA. The physical medium used is optical fiber, as opposed to coaxial cable UTP. Dual 100 Mbps fiber rings are included, allowing for rerouting of data around a fiber fault. FDDI is primarily used as a backbone network to connect multiple lower speed LANs in a large building or campus environment, so would be less commonly used in a substation environment. Also, with the advent of 100 Mbps CSMA/CD, asynchronous transfer mode switching and synchronous optical network technology, FDDI usage should wane in the coming years.

ATM is dedicated-connection switching technology that organizes digital data into packets and transmits them using digital signal technology. Due to ATM's ease in implementation by hardware, faster processing speeds are possible. ATM runs on a layer on top of SONET. SONET is the U.S. (ANSI) standard for synchronous data transmission on optical media. This standard ensures the interconnection between networks and that existing conventional transmission systems can take advantage of optical media through tributary connections. Utilizing this technology can bring data speeds of 155.520 Mbps or 622.080 Mbps. Faster speeds are expected in the near future. These two technologies are a major component of broadband ISDN (BISDN). FDDI usage should wane in the coming years because of this technology.

14.4.5.3   Serial Data Interfaces: Communications between intelligent devices in the substation may take the form of synchronous or asynchronous serial connections rather than a LAN connection. Most RTU vendors, for instance, offer serial ports on their RTUs for interfacing to IEDs with standard protocols. The most common standard serial interfaces are RS-232, RS-422/423, and RS-485. Like LANs, these standards define a physical and electrical interface and do not imply a particular protocol.

14.4.5.3.1   RS-232: The industry's most common serial interface standard, RS-232 is defined by ANSI/TIA/EIA Std. 232-E. It defines the interface between data communications equipment (DCE) and data terminating equipment (DTE) employing serial binary data exchange. RS-232 signals are generally limited to 50 feet or less without the use of special low-capacitance conductors.

14.4.5.3.2   RS-422/423: This standard serial interface is defined by ANSI/TIA/EIA Std. 422 that extends the transmission speeds and distances beyond RS-232. It provides for a balanced voltage interface with a high noise immunity. RS-423 is the unbalanced version.

14.4.5.3.3   RS-485: This standard serial interface is defined by ANSI/TIA/EIA Std. 485. It provides for a balanced voltage interface similar to RS-422, but uses tri-state drivers for multidrop or "daisy-chained" applications. Because of its multidrop capability, this is the most common serial interface in substation data communications.

14.4.6   Communication Protocols

14.4.6.1   General: For two devices to communicate successfully, not only they have to share a common physical interface and access method (see Section 14.4.5, Substation LANs, and Section 14.4.5.3, Serial Data Interfaces), but they have to also share a common protocol. A protocol is a formal set of conventions governing the formatting and relative timing of message exchange between communicating systems. The careful selection of communication protocols is essential for the successful deployment of substation automation systems.

The prevalent approach among equipment manufacturers is to support several standard protocols. One RTU vendor, for example, offers the end user a menu of 34 different protocols for the RTU-to-IED interface port, and a single RTU can support up to 4 of these protocols simultaneously.

Serious initiatives have been under way for several years among industry groups to address the issue of open protocol development and standardization. These industry groups include the Institute of Electrical and Electronics Engineers (IEEE) Power Engineering Society Substations Committee, EPRI, and the National Rural Electric Cooperative Association (NRECA).

In 1994, the IEEE issued a trial use standard (IEEE Std. 1379) that recommended IEC 870-5 and DNP 3.0 as alternative standards for master station-to-RTU and RTU-to-IED communications. DNP 3.0 has fostered the widest support among vendors to date, making it somewhat of a de facto standard throughout the industry. Other protocols that have obtained wide support include ModBus, MMS, ASCII, and Landis & Gyr 8979.

The ISO-OSI 7- layer model is not described due to the complexity of the subject. The user is only exposed to the application layer. For a detailed description, see CRN's *Enterprise-Wide Data Integration in a Distribution Cooperative* (Project 95-12).

14.4.6.1.1   Protocol Descriptions:

- IEC 870-5, developed by IEC Technical Committee 57 Working Group 3, answered the need for a protocol standard for telecontrol, teleprotection, and associated telecommunications for electric utility systems.

- DNP 3.0, developed by GE Harris Canada (at the time Westronic, Inc.), was established to minimize the creation of new protocols used to communicate between SCADA devices. The protocol is designed for data acquisition and application control in the electric utility field. This protocol is maintained by the DNP Users Group.

- ModBus (ASCII and RTU) were developed by Modicon. These protocols define a message structure that controllers are able to recognize and use; the protocol forms a common format for the layout and contents of data messaging.

- Manufacturing Message Specification (MMS) is an internationally standardized messaging system for exchanging real-time data and supervisory control information between networked devices and/or computer applications in a manner that is independent of the application function being performed or the developer of the device or application. MMS is an international standard (ISO 9506) that is developed and maintained by Technical Committee Number 184 (TC 184), Industrial Automation, of the International Organization for Standardization (ISO).

- Landis & Gyr 8979 is another standard byte-oriented protocol commonly used in the utility marketplace.

A promising development in the effort to provide a universal open protocol standard is EPRI's UCA, which is described in Section 14.4.6.2. IEEE Std. 1379 was intended to be an intermediate standard to fill the gap until the UCA standard was completed.

While there are "standard" protocols available, many of these are dynamic in that continuing development and enhancements are taking place. Several versions of a particular protocol may exist in the marketplace. Two devices that claim support of the same protocol may indeed support different versions or revisions of the protocol, resulting in some lack of interoperability. To avoid such problems, it is incumbent on the design engineer to research and understand the history of the selected protocol, whether multiple versions exist, and

what continuing development, if any, is taking place. The designer should also be informed as to any proprietary modifications to the standard protocol that may have been incorporated by potential equipment suppliers as a means of optimizing its implementation with their devices.

The best way to avoid unforeseen protocol interoperability problems is to implement pre-engineered "plug-and-play" interfaces. Equipment manufacturers should be required to demonstrate plug-and-play interoperability between the specific devices in question, not just general compliance with a protocol, either through factory testing or in actual field installations. If a new and untried interface is undertaken, the utility should place the burden for protocol emulation and development on a single entity. This will typically be the RTU manufacturer (in the case of RTU-to-IED interfaces) or the data concentrator manufacturer (in the case of multiple protocol integration).

14.4.6.2 **Utility Communications Architecture:** EPRI developed UCA based on the ISO/OSI standards for data communications. The overall goal of UCA is to provide interconnectivity and interoperability between utility data communication systems for real-time information exchange. UCA employs the Manufacturing Messaging Specification (MMS) to define the language, semantics, and services for real-time data acquisition and control throughout general utility operations. Both the ISO/OSI and the TCP/IP networking models are currently supported under UCA.

UCA Version 1.0 was adopted in 1991, providing a suite of selected protocols, with MMS as the recommended protocol for real-time data acquisition and control applications. But UCA 1.0 lacked detailed specifications of how the protocols would actually be used in field devices. UCA Version 2.0 addresses this problem.

The development of UCA Version 2.0 at the substation level was facilitated by EPRI Project RP-3599, "Integrated Protection, Control and Data Acquisition," in which numerous utilities and manufacturers participated, with American Electric Power (AEP) as the lead participant. This work has generally been completed for power system devices with the issuance of UCA 2.0 General Object Models for Substation and Feeder Field Devices, Draft Version 0.7, December 1997 (GOMSFE). The effort of the document is to merge the substation and feeder automation work with that of UCA version 2.0 in order to produce common generic object models for implementation of UCA 2.0-compliant field devices in electric utilities.

Work on UCA Version 2.0 continued in 1998 with the EPRI/AEP Utility Substation Communications Initiative Project. A continuation of EPRI Project RP-3599, this project's goal is to evaluate and recommend a UCA-compliant substation LAN and to demonstrate IED interoperability. This project includes implementation at 13 demonstration sites in the United States and Germany, with targeted completion in 1999.

Work on the UCA standards should continue over the next few years. A new IEEE subcommittee, SCC 36, will oversee its further development.

14.5   REFERENCES

ANSI Std. C37.1, "Definition, Specification & Analysis of Systems Used for Supervisory Control, Data Acquisition & Automatic Control."

ANSI Std. C37.90a, "Electrical Characteristics of Surge Protectors for Use in Programmable Logic."

ANSI Std. X3T12, "Physical Media Dependent, Physical Media Access Control and Station Management Specifications for Optical Fiber Based Token-Ring Network."

ANSI/IEEE Std. 802.3, "Information Technology- Telecommunications and Information Exchange Between Systems- Local and Metropolitan Area Networks – Specific Requirements – Part 3: Carrier Sense Multiple Access with Collision Detection (CSMA/CD) Access Method and Physical Layer Specifications."

ANSI/IEEE Std. 802.3v, "Information Technology – Local and Metropolitan Area Networks – Part 3: Carrier Sense Multiple Access with Collision Detection (CSMA/CD) Access Method and Physical Layer Specifications, Informative Annex for Support of 150 ohm Cables in 10 BASE-T Link Segment."

ANSI/TIA/EIA Std. 310–D, "Racks, Panels, and Associated Equipment."

ANSI/TIA/EIA Std. 232-E, "Interface Between Data Terminal Equipment and Data Circuit-Terminating Equipment Employing Serial Binary Data Interchange."

ANSI/TIA/EIA Std. 422, "Electrical Characteristics of Balanced Voltage Digital Interface Circuits."

ANSI/TIA/EIA Std. 423, "Electrical Characteristics of Unbalanced Voltage Digital Interface Circuits."

ANSI/TIA/EIA Std. 485, "Electrical Characteristics of Generators and Receivers for use in Balanced Digital Multipoint Systems."

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EPRI/UCA 2.0 GOMSFE, "General Object Models for Substation and Feeder Field Devices," Draft
    Version 0.7, December 1997.

IEC 870-5-101, Telecontrol Equipment and Systems, Part 5: Transmission Protocols- Section 101:
    "Companion Standard for Basic Telecontrol Tasks, First Edition."

IEC 870-5-103, Telecontrol Equipment and Systems, Part 5: Transmission Protocols- Section 103:
    "Companion Standard for the Informative Interface of Protection Equipment."

IEEE Std. 802.4, "Token Passing Bus Access Method and Physical Layer Specifications."

IEEE Std. 802.5, "Information Processing Systems – Local and Metropolitan Area Networks – Part 5: Token
    Ring Access Method and Physical Layer Specifications."

IEEE Std. 1379, "IEEE Trial Use Recommended Practice for Data Communications Between Intelligent
    Electronic Devices and Remote Terminal Units in a Substation."

RS-232, "Interface Between Data Terminal Equipment and Data Circuit-Terminating Equipment Employing
    Serial Binary Data Interchange."

RS-422, "Electrical Characteristics of Balanced Voltage Digital Interface Circuits."

RS-423, "Electrical Characteristics of Unbalanced Voltage Digital Interface Circuits."

RS-485, "Serial Balanced Voltage Interface Using Tri-State Drivers for Multidrop Applications."

APPENDIX H TO CHAPTER 14
GLOSSARY OF TERMS

Asynchronous Transfer Mode (ATM): A communications transmission and switching standard for carrying broadband signals at speeds up to 2.2 gigabits per second. Combines techniques of time division multiplexing and packet switching.

Carrier Sense Multiple Access with Collision Detection (CSMA/CD): A LAN contention-based access-control protocol technique (Ethernet); defined in IEEE Std. 802.3.

Data Circuit-Terminating Equipment (DCE): Formerly known as data communications equipment; network-embedded devices that provide an attachment point for user devices.

Data Terminal Equipment (DTE): The computing instrument, apart from any device used to perform the analog transmission and reception of data; examples are computers, RTUs, and PLCs.

Fiber Distributed Data Interface (FDDI): Shared-medium, ring topology LAN that operates at 100 Mbps. It is ANSI Std. X3T9.5, using fiber-optic cable as the medium.

HMI: Human–machine interface.

Intelligent Electronic Device (IED): Electronic equipment that provides monitoring and controlling capabilities.

Ladder Logic: Industry-standard symbology used to document relay logic control systems. Logic lines are drawn horizontally, similar to the rungs of a ladder.

Legacy: Existing implementation of an application or project; it does not refer to trials.

Local Area Network (LAN): A group of computers connected over a common medium within a building.

Master Station: The "central host" computer in a SCADA system.

Open Systems Interconnection (OSI): An international standard describing seven layers of communication protocols (physical, data link, network, transport, session, presentation, and application) that allow many dissimilar information systems including computers, workstations, PBXs, etc. to be interconnected.

Programmable Logic Controller (PLC): Electronic device that can be programmed using a specific language via a computer.

Remote Terminal Unit (RTU): An electronic device used to control and monitor Input/Output points within an overall system and to communicate the derived data to a master station or other "host" unit.

SCADA: Supervisory Control and Data Acquisition; used by utilities and other process-oriented operations to collect data from machinery that may be located over a widespread area. A basic SCADA system consists

of two types of devices: "master" and "remote." The master resides at a centrally manned location while the remotes are generally placed at unmanned locations. Communication between master and a number of remotes can be via telephone-like circuits, radio channels, or fiber-optic communications media.

SONET: Synchronous Optical Network; standard for optical transport formulated by the Exchange Carrier Standards Association (ESCA) for ANSI; essentially a standard for Broadband Integrated Services Digital Network transmission facilities.

Token Bus: A networking standard that uses a bus configuration and a broadcast messaging system. Token bus networks use a token-passing scheme to determine which node has the network access.

Token Ring: A LAN that uses the token-passing access method and that supports 4 Mbps or 16 Mbps baseband communications in a physical star and logical ring arrangement.

Transport Control Protocol/Internet Protocol (TCP/IP): The main transport protocol used on the Internet for connectivity and transmission of data across heterogeneous systems. It is an open standard that is available on most UNIX systems, VMS and other minicomputer systems, many mainframe and supercomputing systems, and some microcomputer and PC systems.

Utility Communications Architecture (UCA): Developed by EPRI based on the ISO/OSI Standards for data communications.

UTP: Unshielded Twisted Pair.

Wide Area Network (WAN): A computer network interconnected over distances beyond a city or metropolitan area.

CHAPTER 15
AC AND DC AUXILIARY SYSTEMS

15.1 AC AUXILIARY SYSTEM

15.1.1 Typical Loads Supplied

Substation ac auxiliary systems are typically used to supply loads such as:

1. Transformer cooling, oil pumps, and load tap changers
2. Circuit breaker air compressors and charging motors
3. Outdoor device heaters
4. Outdoor lighting and receptacles
5. Control house
    a. Lighting and receptacles
    b. Heating, ventilating, and air conditioning
    c. Battery charger input
    d. Water well pump
6. Motor-operated disconnecting switches

15.1.2 Design Requirements

15.1.2.1 Demand Load: Tabulate the connected kVA of all substation ac loads and apply a demand factor to each. Demand kVA is used to size the auxiliary transformer(s). Load diversity and load factor need not be considered in this case.

In auxiliary transformer sizing, examine the substation growth rate. If expansion is planned in the near future, consider the estimated demand load of the expansion in the transformer size. If expansion is in the far future, it may be economically advantageous to plan for the addition of a transformer at expansion time.

15.1.2.2 Number of Primary Feeds: In small distribution substations one auxiliary transformer is usually sufficient.

As substation size increases, customer load criticality increases. A decision has to be made as to redundancy of substation auxiliary services in light of economics and customer requirements. Large transmission substations, servicing large load blocks, and distribution stations, should have dual feeders serving two separate auxiliary transformers.

When dual feeds are selected, locate two separate, independent sources so the loss of one will not affect service of the other. Designate the least reliable as the alternative supply. A popular option to consider in this case is the use of a tertiary winding of the power transformer as a normal source.

An alternative source could be a distribution feeder at a customer service level, 480 or 240 volts, single or three phase. Depending on auxiliary secondary voltage level selected, this could eliminate one transformer.

15.1.2.3   Overhead or Underground Entry: The auxiliary source(s) could be either overhead or underground distribution lines. When undergrounding within the substation property, even from an overhead source, direct-buried conduit is recommended. A spare, capped, conduit should be installed to minimize down time if a cable failure occurs. The faulted cable can always be removed after service restoration.

15.1.2.4   Critical Loads: Some low-voltage loads have to be maintained at all times:

1. Battery chargers which, through the batteries, supply breaker trip and close circuits as well as communication circuits
2. Transformer cooling
3. Power circuit breaker compressors and motors
4. Trouble light receptacles in the station yard
5. Security lighting
6. Breaker control circuits
7. Fire alarm circuit(s)
8. Electric heating
9. Substation automation circuitry

Critical loads for each station should be determined. These loads should be served from a panel(s) fed from the normal source and representing the minimum load for transfer to alternative supply.

15.1.2.5   Secondary Voltage Level: Several secondary voltage or utilization levels are available for ac auxiliaries. For the purposes of standardization, on a given power system it is best that only one level be selected. This is not a limiting rule, however. An exception could be justified.

Possible secondary voltage levels as illustrated in Figure 15-1 are as follows:

1. **480/240 Volts, Three-Phase Delta**

Three-phase transformer fans and oil pumps need to be specified at 480 volts. In practice, the units are rated at 460/230 volts, but this is inside the NEMA plus 10 percent voltage requirement.

Other loads may be specified at either 480 or 240 volts, single phase.

This system is ungrounded and should be used with a ground detection system so that a "fault" or one leg of the system will cause an alarm. The system should trip when a second leg on the system is grounded.

2. **480/277 Volts, Wye Connected, Three-Phase, Four-Wire**

Three-phase transformer fans and oil pumps need to be specified at 480 volts. In practice, the motors are rated 460/230 volts, but this is within the NEMA plus 10 percent voltage requirement.

The advantage here is that luminaires can be equipped with 277-volt ballasts, saving lighting transformer costs over use of more common 120-volt lamped luminaires. Convenience receptacles are fed through small dry-type 480-120 volt transformers.

a. 480/240 VOLT, 3ø DELTA

b. 480/277 VOLT, 3ø Y
c. 208/120 VOLT, 3ø Y

d. 240 VOLT, 3ø DELTA

e. 240/120 VOLT, 3ø DELTA
f. 240/120 VOLT, 3ø OPEN DELTA
(OMIT X_1-X_2)

g. 240/120 VOLT, SINGLE PHASE
3 WIRE

NOTE: A 0° OR 30° PRI. TO SEC. ANGULAR DISPLACEMENT MAY
EXIST DEPENDING ON PRIMARY CIRCUIT (Δ OR Y)

Figure 15-1: Typical AC Auxiliary System Secondary Voltages

3. **208/120 Volts, Wye-Connected, Three-Phase, Four-Wire**

Three-phase 208 volts or single-phase 120 volts or a combination of the two can be used for transformer cooling. Combination power and lighting panels can be used, resulting in reduced labor and material costs. This saving could be offset by higher conductor costs as compared to the 480-volt system. Receptacles can be served with 120 volts directly.

4. **240 Volts, Three-Phase Delta**

Three-phase transformer fans and oil pumps need to be specified at 240 volts. In practice, the motors are rated at 230 volts, but this is inside the NEMA plus 10 percent voltage requirements.
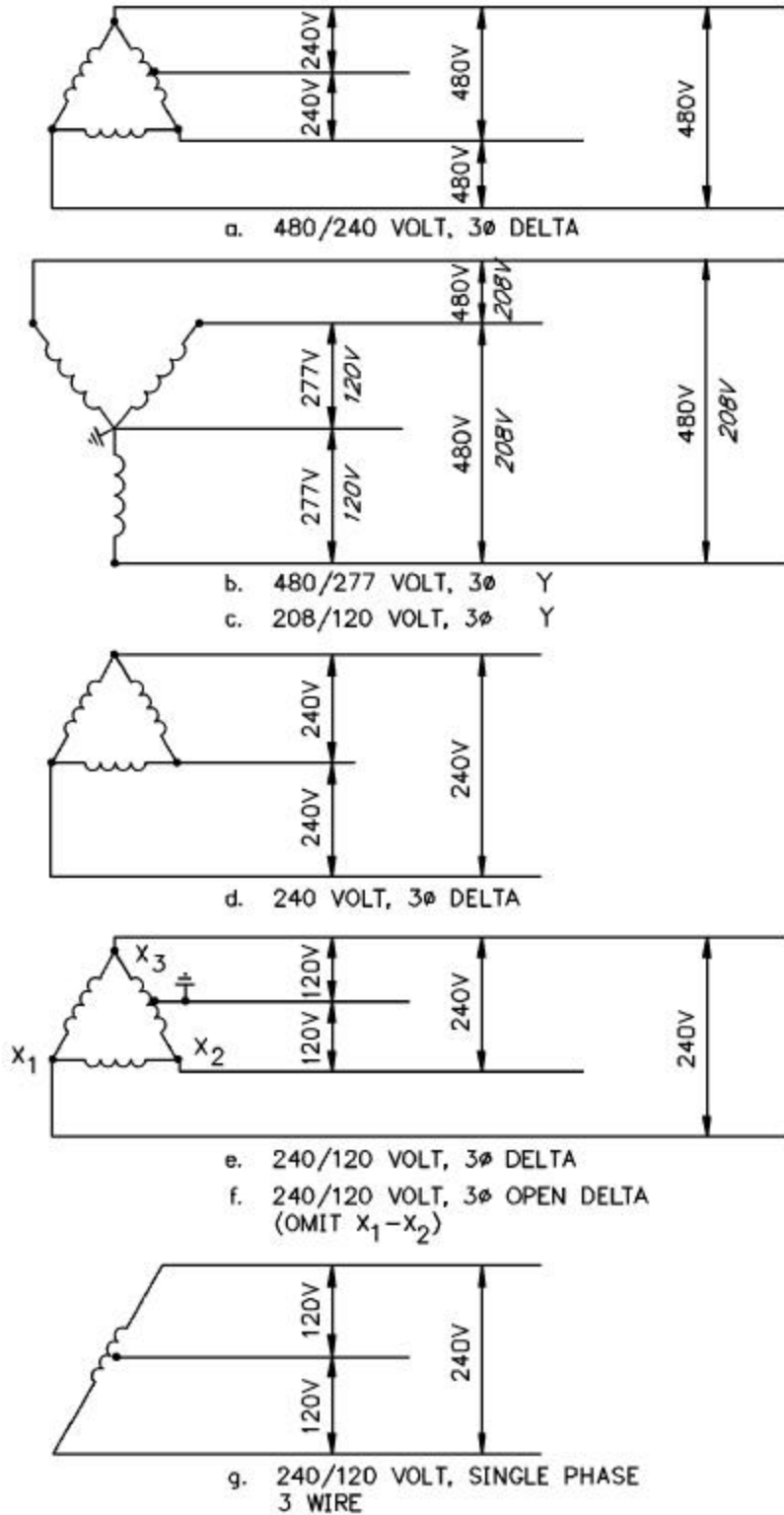
This system is ungrounded and should be used with a ground detection system so that a "fault" on one leg of the system will cause an alarm. The system should trip when a second leg on the system is grounded.

5. **240/120 Volts, Delta-Connected, Three-Phase, Four-Wire**

This is the most common level in use in moderate-size substations. One phase of the auxiliary transformer is center tapped to obtain 120 volts. Combination panels can be used, and 240-volt single-phase loads can be served.

6. **240/120 Volts, Open Delta-Connected, Three-Phase, Four-Wire**

This is essentially the same as the closed delta connection except only 58 percent of the kVA capacity of the three transformers can be used. This configuration will provide construction economy for a medium-size installation or for temporary use. With single-phase units, the third transformer can be added in the future for increased kVA capacity. It is frequently used for construction power where both three-phase and single-phase supplies are required.

7. **240/120 Volts, Single-Phase, Three-Wire**

This is "residential" service but applicable to small substations. Common panels can be used, with two available voltages.

15.1.2.6   Transfer Scheme: Where two sources, normal and alternative, are feeding substation auxiliaries, a means to transfer from one to the other has to be established. At an attended station this can be a manual transfer arrangement. Automatic transfer has to be provided at an unattended station. Transfer is done on the secondary side for equipment economy. Article 700 of the *National Electrical Code* (*NEC*) outlines general requirements for this type of scheme. A typical configuration is shown in Figure 15-2.

Transfer switch selection is an important factor in the system design. Operation should be "break before make" double-throw operation to prevent shorting the two sources. Mechanical interlocking should be provided to ensure the switch can be in only one of the two positions. The switch should have an ampere withstand capability for faults at points A, B, and C of Figure 15-2. The fault at C will be highest, the feeder impedance to B and A limiting the fault current to an amount below that at C.

The auxiliary system in Figure 15-2 assumes transfer of all loads. The full load current of the 150 kVA transformer is 360 amperes, so a 400-ampere switch would be selected.
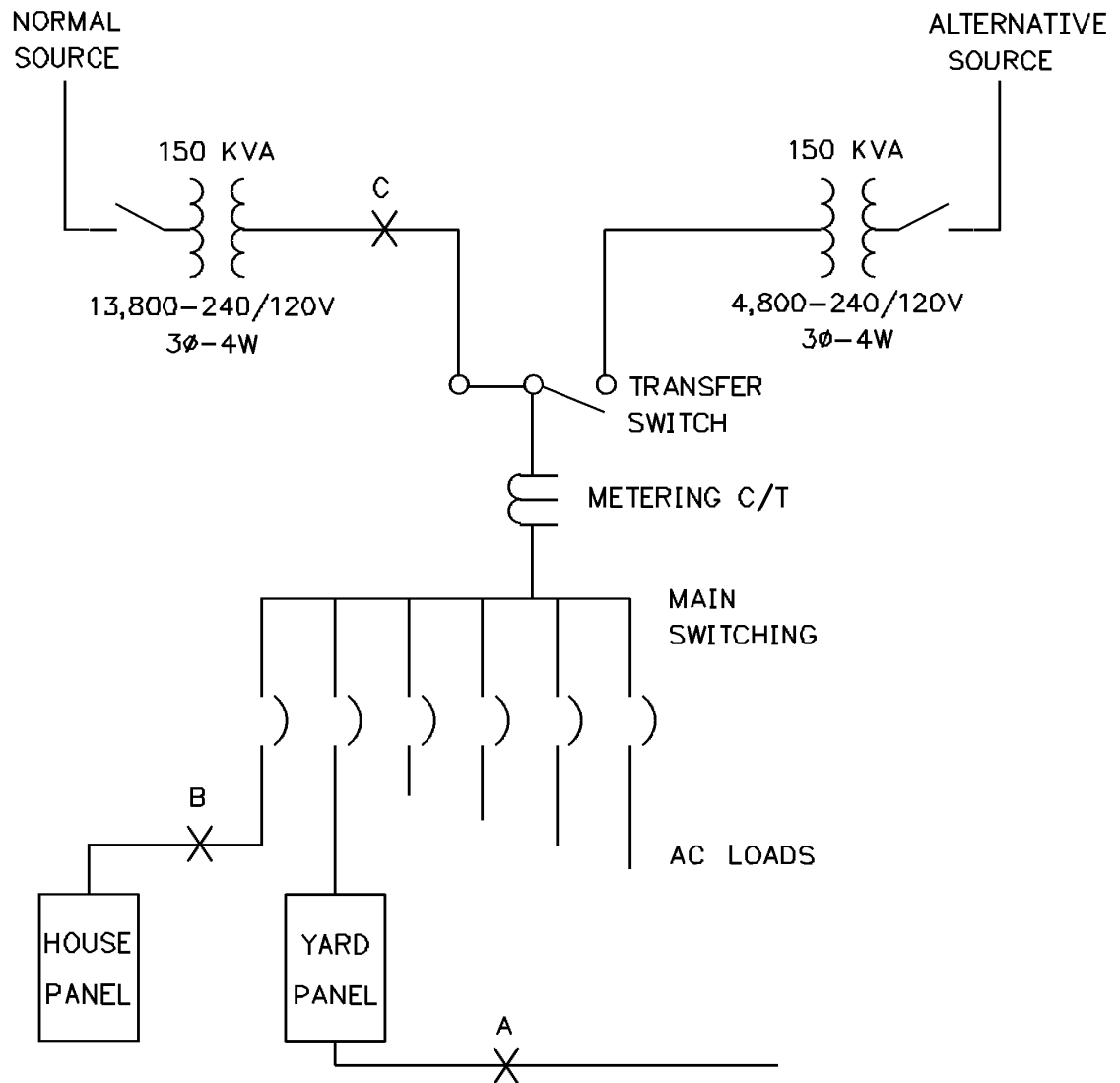
Figure 15-2: Typical AC Auxiliary System

Assuming a 250,000 kVA source, two 500 kcmil, 3.05-meter (10-foot) feeders per phase to the switch, and 4 percent transformer reactance, the fault current is approximately 10,000 amperes. This value is well within manufacturers' standard ratings for 400-ampere full load transfer switches.

Automatic transfer switches are built to detect emergency conditions and transfer to the alternative supply when the normal supply falls to 83 percent of rated voltage. Return to normal supply is accomplished through an adjustable time delay at approximately 92 to 95 percent of rated voltage. A variety of accessories are available with transfer switches. Manufacturers' data is readily available, and the engineer should consult such data when specifying a transfer switch. Provide means to alarm for loss of voltage from either source.

15.1.2.7 Auxiliary System Fault Currents: The determination of fault currents in three-phase ac auxiliary systems is just as basic as the determination of load currents in sizing circuit breakers or fuses.

The protective device has to operate or open during faults as well as carry load current during normal conditions or equipment damage could result.

The symmetrical short circuit (fault) current is computed using Equation 15-1:

Equation 15-1

$$I_F = \frac{\text{Line - to - Line kV}}{\sqrt{3} * \text{Ohms Reactance}}$$

Ohms reactance is the total reactance of all current-carrying parts from the source to the fault.

In Figure 15-2 the 250,000 kVA source has a reactance of 0.00023 ohms. The 150 kVA transformer reactance is 0.0023 ohms, the current transformer 0.0005 ohms, the 3.05-meter (10-foot) cable about 0.001 ohms, and so forth. All reactances are totaled and used in Equation 15-1. The asymmetrical fault current is a function of the fault circuit X/R ratio. A multiplying factor (1.7) for the asymmetrical current is satisfactory for auxiliary power system calculations.

Fuse and circuit breaker manufacturers have handbooks with X, R, and Z values for transformers, current transformers, cables, etc., together with methods for determining protective device ratings based on estimated fault currents.

15.1.3 Equipment

15.1.3.1 Transformers: ANSI Std. C57.12.25, "Pad-Mounted Compartmental-Type, Self-Cooled, Single-Phase Distribution Transformers with Separable Insulated High-Voltage Connectors; High Voltage, 34500 GRD Y/19920 Volts and Below; Low Voltage, 240/120 Volts; 167 kVA and Smaller—Requirements," and ANSI Std. C57.12.26, "Pad-Mounted Compartmental-Type Self-Cooled, Three-Phase Distribution Transformers for Use with Separable Insulated High-Voltage Connectors, High Voltage, 34500 GRD Y/19920 Volts and Below; 2500 kVA and Smaller," are applicable for selection of ac auxiliary system pad-mounted transformers. This type of transformer is good for large substation auxiliary service use. The increasing use of underground distribution has made these units readily available from major manufacturers. Pad mounts meeting RUS specifications and with RUS accessory packages are catalog items.

The secondary voltage levels listed in Section 15.1.2.5 are manufacturers' standards.

Consider the feasibility of establishing substation auxiliary system voltage at the same level as that for serving underground customers. With this standardization, spare transformers can be stocked and both customer and substation service maintained at minimum cost.

Pad-mounted transformers can be purchased with fused switches on the primary side for transformer fault current protection. High-voltage fuses, in this use sized for full-load transformer primary currents, will inherently have sufficient current interrupting ratings to protect the transformers under fault conditions. Primary load break switches are also available.

If the normal and alternative sources are overhead, pole-mounted, and hook stick operated, fused switches are a possible solution to transformer primary protection. Underground cable is used for the connection from the switches to the transformer pad. Cable for this application is discussed in Chapter 10.

Pad-mounted transformers and the kVA ratings previously mentioned apply to a fairly large substation. For smaller installations, structure-mounted distribution transformers, properly applied, can be used.

15.1.3.2   Electrical Panelboards: The definition of a branch circuit panelboard in the *NEC* (Article 384) is one having more than 10 percent of its overcurrent devices rated 30 amperes or less for which neutral connections are provided. Additionally, the number of branch circuit devices in one enclosure is limited to 42 poles.

Switchboards differ from panelboards in that switchboards are free standing. Front or rear access to line and load terminals are vendor options. Branches can be group mounted or individually mounted, with or without barriers.

Enclosures should be specified NEMA 1, general service for indoor use, or NEMA 3R, raintight for outdoor use.

Panelboards are available for flush or surface mounting, with fusible or circuit breaker branch circuits. Main breakers, if required, can be furnished. Voltage ratings for any level selected from Section 15.1.2.5 can be supplied.

The main decision to be made in panelboard selection is whether to use fusible or circuit breaker branches. The branch circuit device is used to protect the branch circuit wiring, so the decision should be based on first cost and maintainability. For a very small installation with few circuits, fuses will mean lower first cost.

If fuses are selected, an inventory has to be maintained at the substation. There is always the possibility, however remote, that the wrong size could be used as replacement for a blown fuse. These problems do not exist with circuit breakers, a plus factor relative to maintainability.

For lighting circuit service exclusively, in a moderately sized installation, a circuit breaker panelboard offers the advantage of switching the lights, thereby eliminating light switches. For exterior lighting, the engineer may consider mounting a weatherproof three-pole magnetic contactor fed from an adjacent outdoor panel.

15.1.3.3   Lighting and Heating Equipment: Outdoor lighting serves two basic purposes: substation security and safety. Depending on the area, certain luminaires may be used during hours of darkness for substation security. These are photoelectrically controlled. A microwave tower could require FAA lighting. This would also be controlled photoelectrically.

Lamps for outdoor use are essentially incandescent, mercury, or sodium lamps. Except for an unusual condition, the lamps presently in use on a given system should continue in use, simplifying inventory. The unusual condition could be a new large substation where a different source is desirable and a separate, on-station inventory can be kept.

Luminaires for substation use, from the basic flat dome reflector to Illuminating Engineering Society (IES) pattern refractors, are available. Pole-top or bracket mountings can be used. The engineer, with the proper vendor data, can develop a lighting layout to satisfy the purpose required. Yard lighting design is beyond the scope of this guide. The basic requirements are one or two foot-candles in equipment areas. Convenience receptacles should be in equipment cabinets and also strategically located to serve 50-foot extension cords with trouble lights. Convenience receptacles in the substation yard should have ground fault interruption protection.

Indoor lighting should be designed for maximum operator convenience. Luminaires should be located to adequately illuminate relay and control panel fronts. With fluorescent units, 4-foot lamps are recommended, since storage is easier than for 8-foot lamps. Provide duplex receptacles for extension cord lights for initial panel interconnection work, relay setting, and plant maintenance.

Provide control house electric heating for comfort and freeze prevention. This can be done with ceiling or wall-mounted electric unit heaters and/or electric baseboard heating units. Provide powered roof ventilator(s) along with floor-level, manually operated wall louver(s) to provide for three to five air changes per hour. Louvers should be provided with fusible links as a means, in case of fire, to keep damage to a minimum. Gravity roof ventilators should always be installed to prevent concentration of hydrogen in battery rooms.

Air conditioning of the control house, where required, is best provided by packaged through-wall unit(s). Packaged through-wall units pump an energy-efficient heating/cooling option for most climates and can have supplemental resistance heat. Built-in resistance heaters are provided in some to provide all-season use. Vendor data is available as an aid in selecting such units.

15.1.4   Summary

A substation ac auxiliary system consists mainly of the following parts:

a.   One or two incoming primary feed(s) seldom above the 34.5 kV level, one designated normal source, the other designated alternative source. The sources should be as independent as possible.

b.   One or two auxiliary transformers to reduce the primary voltage to the utilization level.

c.   A main switchboard, usually located outdoors between the two transformers. This switchboard houses the transfer switch and fuses or circuit breakers to feed both control house and yard panelboards.

Panelboards (indoor or outdoor) having circuit breakers or fuses sized for the loads involved should have approximately 20 percent spare breakers or fuses.

All branch circuit breakers feeding ac yard circuits shall be Ground Fault Interrupting type (GFI). Where fused panels are selected, yard receptacles shall be GFI type.

15.2   DC AUXILIARY SYSTEM

15.2.1   Typical Loads Supplied

Substation dc auxiliary systems are typically used to supply loads consisting of the following:

a.   Relaying, supervisory, alarm, and control equipment

b.   Emergency control house lighting

c.   Circuit breaker trip and close circuits

15.2.2   Design Requirements

A substation dc system consists of a battery of suitable voltage (number of cells) and suitable size (ampere-hour capacity) connected in parallel with a control bus together with properly selected voltage-regulated charging equipment.

At a single location where two distinct dc voltages are required, i.e., possibly 48 volts for microwave and 120 volts for substation operation, two separate batteries and chargers is one option. Tapping a larger unit to obtain the smaller voltage is not recommended. Another option to obtain different dc voltages is a dc-to-dc converter. This is usually used for small loads and is available from the manufacturer.

The charging equipment consists of a full wave rectifier with regulated output voltage. Normally, the charger operates continuously to furnish direct current to the control bus for steady loads such as indicating lamps, holding coils, and relays, plus a small current to maintain the battery at full charge. Intermittent loads of short duration such as tripping or closing of circuit breakers or automatic operation of other equipment are handled by the charger within the limits of its capacity. Any excess load is supplied by the battery, which is automatically recharged when the intermittent load ceases. Should the ac input to the charger fail, the battery carries the entire load.

The control bus may be a dc bus in a switchgear assembly or, in the case of a large substation, a dc or group of dc panels.

DC voltage requirements for solid-state relaying, event recorders, data acquisition, and other such devices are generally below the voltage levels for circuit breaker trip coils. Actual requirements vary with different vendors. Some types of equipment are provided with individual rectifiers, rack mounted, changing 120 volts, 60 hertz ac, to 12, 24, or 48 volts dc. If the ac supply fails, static switching changes the source to the main dc batteries and required dc converter. An alarm indication is provided to indicate this status. Other equipment is designed to be fed directly from the main batteries with ac/dc converters to supply the static device voltage.

Two of the most important components of a substation dc system are the main battery and charger. These components should be sized correctly. Undersizing could possibly mean a circuit breaker reclose failure and undue service interruption. Oversizing, while not damaging, is expensive. However, the cost of the supply is a fraction of total substation cost, and the economics should be balanced with reliability. At a minimum, the main battery should be sized to allow normal substation operation for 8 hours.

15.2.3   Types of Cells

Before determining the cell ampere-hour rating, the type of cell for the particular application has to be selected. There is no need for cell standardization on a power system. Once a battery is installed for stationary service, it stays in place for up to 30 years. Interchangeability on the system is unnecessary. The types of secondary cells readily available today are:

1.   Lead acid
2.   Nickle cadmium (NI-CAD)
3.   Lead calcium

A brief description of the three predominant types follows. For theory and history too lengthy to be considered here, see *Batteries and Energy Systems* by Dr. C.L. Mantell.

In the case where no standards are established, select battery type based on:

1. First cost
2. Years of float life
3. Annual depreciation
4. Number of deep discharges required over the life of the battery

15.2.3.1   Lead Acid Cell: This cell has a positive plate of lead peroxide and a negative plate of pure sponge lead. The electrolyte is dilute sulphuric acid. Open circuit voltage of a fully charged cell is a nominal 2.25 volts; voltage varies depending on electrolyte strength and cell temperature.

Battery condition can be determined with a hydrometer using Equation 15-2:

Equation 15-2

Cell Volts = S. G. + 0.84

Where:
S. G. =   Specific gravity of the electrolyte

The specific gravity of the electrolyte varies with cell temperature, so a thermometer should be a part of the maintenance kit. The higher the temperature, the lower the specific gravity. Battery ratings are usually specified at 25ºC (77ºF). Temperature correction curves are included with the battery manufacturer's instruction manual, as are charge and discharge curves.

15.2.3.2   Nickel Cadmium: This cell has a positive plate of nickel hydrate and a negative plate of cadmium sponge. The electrolyte is a solution of potassium hydroxide with a specific gravity from 1.160 to 1.190 at 25ºC (77ºF). Open-circuit voltage may vary from 1.30 to 1.38 volts. The cell voltage is 1.4 volts fully charged at 25ºC (77ºF). The specific gravity of the electrolyte is constant regardless of charge state.

The nickel cadmium battery has the advantages of infrequent maintenance requirements, absence of corrosive fumes, immunity to inadvertent overcharge, and the reduced derating required for ambient temperatures below 25ºC (77ºF). The absence of corrosive sulphuric acid fumes allows the installation of "NI-CADS" in cubicles, a possible advantage in some installations. The primary reason for the lack of greater use of NI-CADS for main substation batteries is initial cost.

15.2.3.3   Lead Calcium: This cell is similar to the lead acid type with the exception of the addition of approximately 0.8 percent calcium to the lead grid for additional strength. This alloy also greatly reduces cell internal losses.

15.2.4   Typical Loads and Duty Cycle

To accurately specify a battery and associated charger, the dc load has to be accurately defined. Each single item of equipment connected to the dc system has to be individually tabulated with the following pertinent data included:

- Voltage
- Current requirement
- Duration of operation

- Frequency of use

The last two items constitute the duty cycle.

DC voltages of 24, 32, 48, 120, and 240 are normally encountered in substation design. For the purpose of this guide, a 120-volt battery with a nominal voltage per cell of 2 volts and 60 cells will be considered. A final voltage of 1.75 per cell or 105 volts for the battery will complete our model.

DC system loads consist of both continuous and intermittent loads. Continuous load typically involves the battery 3- to 8-hour ratings. It consists of indicating lights, relays, and any other equipment continually drawing current from the dc bus. Emergency lighting consisting of circuits energized during an ac outage plus certain communication circuits involving the 1- to 3-hour rating.

Intermittent or momentary load, constituting relay and breaker operation, involves the 1-minute battery rating. The duration of breaker operation may be only a few cycles, but the battery voltage drop will be essentially the same after 1 minute. A typical duty cycle will have the breakers tripping at the beginning of the cycle and closing at the end of the cycle. If two or more breakers are to operate simultaneously, the total current determines the 1-minute rating.

The sizing of dc cables and cabinets is done in the same way as for ac services. The only exception is that no demand factor should be applied to connected loads. Voltage drop should be held to within 3 percent. Special consideration of short-circuit capacity is not a factor in a dc auxiliary system.

Figure 15-3 illustrates a typical dc system for substation auxiliary services.

15.2.5 Equipment

15.2.5.1   Battery Selection: Lead batteries are rated in ampere-hour capacity at an 8-hour rate to 1.75 volts average at 25ºC (77ºF).

EXAMPLE 15-1: Battery Selection

The model duty cycle could be:

Ten 40-watt, 120-volt lamps - 3 hrs.	3.5 amperes
Relays and panel indicating lamps - 8 hrs.	5.0 amperes
Communications - 3 hrs.	5.0 amperes
Three simultaneous Breaker Operations - 1 min.	100.0 amperes

From vendor data a cell of seven plates will furnish approximately 200 amperes for 1 minute to 1.75 final volts. The ampere-hour capacity of the selected unit at the 8-, 5-, 3-, and 1-hour rates is about 145, 130, 115, and 80, respectively.
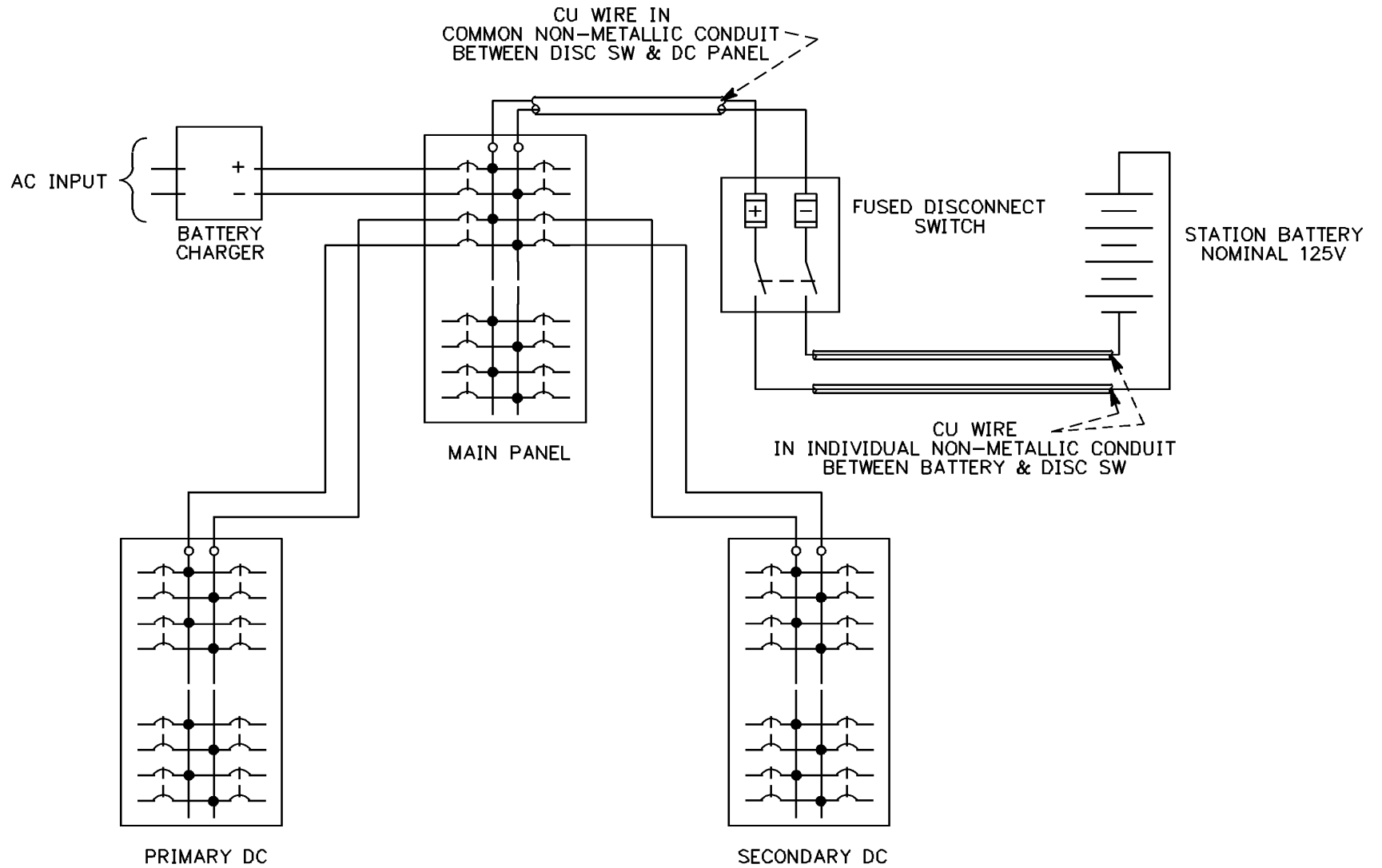
Figure 15-3: Typical DC Auxiliary System

This model duty cycle is only to serve as a numerical example of battery selection. For the 120-volt system, 60 of the lead calcium cells would be connected in series. Quite obviously, vendor data is necessary to specify a battery.

15.2.5.2   Charger Selection: Satisfactory battery life and service are more dependent on the design and specification of the charging equipment than on any other external factor. The most costly and complicated charger is not necessarily the best selection. Shunt wound dc generators were used for years for charging batteries, but frequent adjustment was required and recharge capability was slow. For substation service, bridge rectifiers are used. Tube type is still in service, but new installations are being specified with solid-state devices.

The ampere capacity of the charger can be determined using Equation 15-3:

Equation 15-3

$$A = L + \frac{1.1C}{H}$$

Where:

A = Charge capacity (amperes)
L = Continuous load (amperes)
C = Discharge (amperes hours)
H = Recharge time (hours)

EXAMPLE 15-2: Charger Selection

Using the same model as for battery selection, we have:

DC Lights	3.5 Amperes-3 hrs.	10.5	AH
Communications	5.0 Amperes-3 hrs.	15.0	AH
Breaker operations	100.0 Amperes-l min.	1.7	AH
Panel load	5.0 Amperes-8 hrs.	40.0	AH
		67.2	AH

Substituting in Equation 15-3 with an 8-hour recharge:

$$A = 5 + \frac{1.1 \times 67.2}{8} = 14.24 \text{ Amperes}$$

The next largest standard size charger should be selected. If the charger is to be operated at altitudes above 1000 meters (3300 feet) and above 40°C (104°F) ambient, check vendor data for correction factors.

The model illustrated here is only to demonstrate a method for battery selection. Also consider substation expansion in initial battery/charger selection.

Single- and three-phase ac inputs at standard voltages are available. Chargers are commercially available with standard and optional devices to indicate status and to alarm unusual situations, mainly ac failure. Refer to vendor data to determine the required devices pertinent to the particular situation under

consideration. If the selected charger uses a cord, cap, and receptacle for ac supply, specify a locking cap and receptacle.

Also determine if the battery charger is to function as a battery eliminator. This would allow the battery to be disconnected for short periods to allow maintenance on the battery without disrupting 120-volt dc service. Many of the newer electronic and microprocessor devices require a relatively stable dc supply, with a minimal ac compound associated with the dc supply. The battery while connected into the dc system provides this filter. If the battery is disconnected, the battery charger filtering may be inadequate to prevent damage to the relay dc input filters, causing the relays to be damaged. In such cases where the battery charger is to be used as a battery-eliminator type of charger, compare the ac ripple component specifications on the dc equipment inputs with the ratings for the battery charger.

15.2.5.3   DC Panels and Wiring: The substation dc auxiliary system should be an ungrounded system with fuse or circuit breaker panels for dc service. The trend is to use circuit breaker panels.

It is recommended that the positive and negative legs of the dc system be run in separate PVC conduits from the battery to the first fusible disconnect. This reduces the possibility of the positive and negative legs of the battery becoming shorted together with no means of clearing the short circuit. Also, the battery charger should be specified with a ground detection system so positive or negative grounds are detected. Figure 15-4 is a simplified diagram of such a method.

Relay panels having solid-state equipment cannot sustain voltages higher than 140 volts dc without possible relay damage. When the battery is being recharged or equalized, the dc terminal voltage could be in excess of 140 volts. In this case install a 50/60 cell switch and do the recharging at the 50 cell position. Additionally, circuit breaker operation can cause transient voltage spikes that could possibly damage equipment connected to the dc bus. Install a surge rectifier across the battery to drain the surge energy to ground. These features are usually not available from battery charger manufacturers, so it is recommended that they be installed in the battery room on a wall-mounted wood panel. Figure 15-3 illustrates a simplified diagram of a dc system with these features. Many utilities will remove one or two cells from the battery bank to avoid the problem of overvoltage while the battery is being equalized. Complete an evaluation to guarantee the values of current, load, and power supply will stay in specified levels during the process.

15.3   REFERENCES

ANSI Std. C57.12.25, "Pad-Mounted Compartmental-Type, Self-Cooled, Single-Phase Distribution Transformers with Separable Insulated High-Voltage Connectors; High Voltage, 34500 GRD Y/19920 Volts and Below; Low Voltage, 240/120 Volts; 167 kVA and Smaller—Requirements."

ANSI Std. C57.12.26, " Pad-Mounted Compartmental-Type, Self-Cooled, Three-Phase Distribution Transformers for Use with Separable Insulated High Voltage Connectors; High Voltage, 34500 GRD Y/19920 Volts and Below; 2500 kVA and Smaller."

Mantell, C.L., Dr., *Batteries and Energy Systems*, 2nd ed. New York: McGraw Hill Book Company, 1983.

National Fire Protection Association (NFPA) Std. 70, *NEC*, Article 384, "Switchboards and Panelboards."

National Fire Protection Association (NFPA) Std. 70, *NEC*, Article 700, "Emergency Systems."

(+)   (−)

POS. GRD.   NEG. GRD.

S1   S2

V
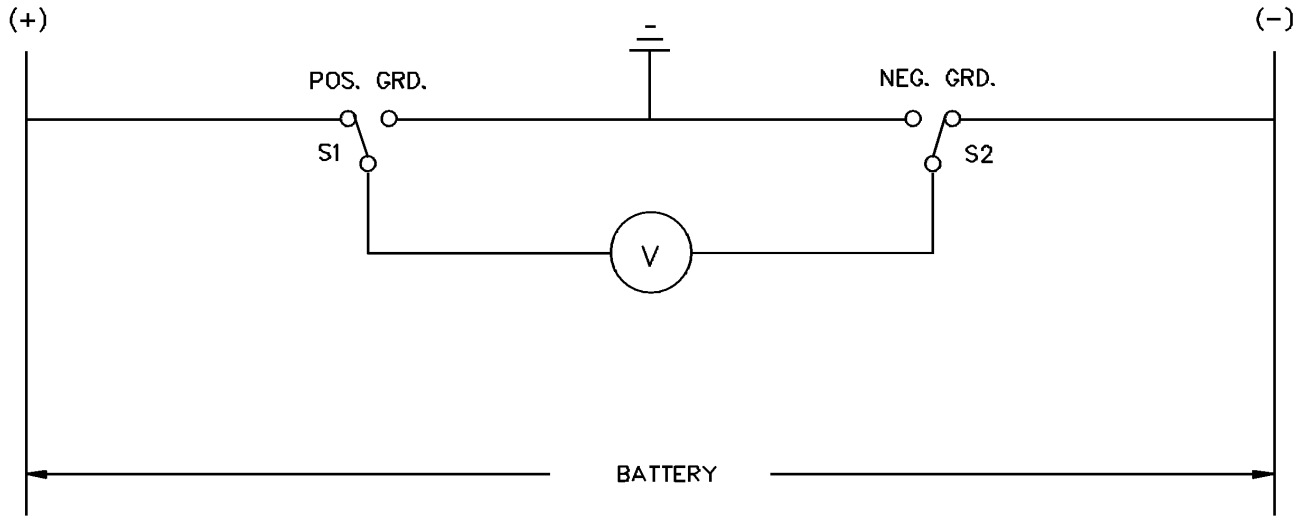
BATTERY

IN THE NORMAL POSITION SWITCHES 1 AND 2 ARE AS SHOWN AND THE
VOLTMETER READS THE FULL BATTERY VOLTAGE. TO CHECK FOR A
GROUND ON THE POSITIVE LEG SWITCH NUMBER 1 SHOULD BE TURNED
TO THE ALTERNATIVE POSITION AS SHOWN.

(+)   (−)

POS. GRD.   NEG. GRD.

S1   S2

V
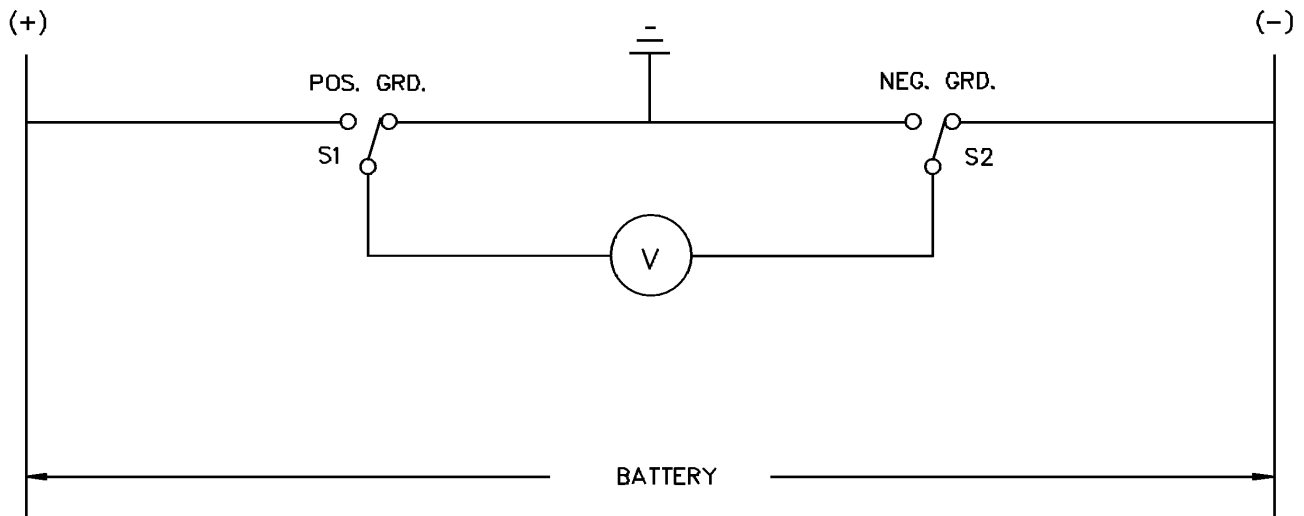
BATTERY

THE VOLTMETER WILL THEN READ 0 VOLTS IF THERE IS NO GROUND
ON THE POSITIVE LEG. IF THERE WERE A GROUND THE VOLTMETER
WOULD AGAIN READ FULL VOLTAGE.

Figure 15-4: Typical Battery Ground Detection System

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CHAPTER 16
CONTROL HOUSES

16.1   INTRODUCTION

As substations increase in voltage, size, and complexity, the necessity for supplemental equipment such as relays, meters, controls, batteries, communications equipment, and low-voltage distribution equipment also increases. For small distribution substations, this equipment can usually be contained in weatherproof enclosures or control cabinets. For larger substations, separate equipment housing is necessary.

A control house provides a weatherproof and, if required, environmentally controlled enclosure for supplemental substation equipment. Additional space can be provided for workshops, equipment testing and repair, storage areas, and lavatory facilities.

Medium- and low-voltage switchgear can also be contained within control houses, or this equipment may be contained within weatherproof enclosures dedicated to that purpose. Switchgear is discussed in more detail in Section 5.4.

16.2   CONTROL HOUSE CONSTRUCTION

This section discusses general aspects of the control house construction. It does not attempt to cover all details of construction. RUS 1724E-400, "Guide to Presentation of Building Plans and Specifications," presents details that will apply and should be consulted.

16.2.1   Foundation

The control house foundation typically consists of a spread footing with either masonry blocks or cast-in-place walls. The footing is designed for an allowable bearing capacity based on soil data. If soil data is not available, a maximum bearing of 48 kPa (1000 lb/ft^2) can be used. The footings are installed below frost depth and in accordance with local building codes and practices.

Drilled piers are an alternative to spread footings. Drilled piers are especially applicable for pre-engineered metal buildings with structural supporting bases that can rest directly on the piers without requiring a concrete floor slab. Soil data is necessary for determining the required depth, diameter, and reinforcing of the piers.

Damp-proofing of foundation walls is desirable, especially if concrete block is used. If a basement level is constructed, damp-proofing should be provided. Footing drains are usually provided when a basement level is constructed.

All foundation walls should be insulated with a 5.1-cm (2-inch) thickness of rigid insulation for energy conservation. It is preferable to install the insulation on the inside of the walls, although the outside is acceptable.

16.2.2   Floor

The control house floor is typically a floating concrete slab 12.7 to 15.2 cm (5 to 6 inches) thick

reinforced with welded wire fabric, deformed steel bars, or a combination of both. The finished floor elevation is usually 10.2 to 20.3 cm (4 to 8 inches) above the finished grade outside the control house.

The base beneath the floor slab should be 10.2 cm (4 inches) of compacted sand or gravel, thoroughly mixed and compacted sand or gravel, or thoroughly mixed and compacted natural soil. A 0.15 mm (0.006-inch) thick plastic film vapor barrier should be installed between the floor slab and the base.

The method for cable routing in the control house has to be considered before finalization of the floor slab design. Cable trenches can be formed into the floor slab, or false floors can be installed providing access to large areas below the finished floor.

16.2.3 Superstructure

The control house superstructure should be constructed from fire-resistant, low-maintenance building materials. Most control houses presently being designed and constructed are of the pre-engineered metal or masonry block type. Figures 16-1 through 16-3 show examples of some control building superstructure types.

Figure 16-1: Pre-Engineered Metal Control Building (Coffeyville, KS)

The pre-engineered metal building is the easiest to procure and erect. The manufacturer can design and fabricate the required building components when given the building size; wind, snow, and ice loads; and any special requirements such as additional roof loads for suspended cable trays or other equipment.

Masonry buildings constructed of block masonry are most economical when masonry module dimensions are used to size the building and the building openings.

Figure 16-2: Typical Masonry Block Control Building

Figure 16-3: Architecturally-Pleasing Masonry Building (Rochelle)

Decorative block can be used as an inexpensive method to improve external appearance. Block cores should be filled with vermiculite or equivalent insulation.

Two types of roof systems are commonly used for masonry buildings: precast, prestressed concrete panels; and steel joists and steel decks. A sloping roof is recommended for both systems and can be obtained by pitching the roof deck or installing tapered roof insulation. The roof membrane has to be compatible with the slope. For the slopes of 8.3 cm/m (1 in./ft) and less, built-up pitch and slab is commonly used. For greater slopes, gravel is used.

The control house should be equipped with at least one double door, possibly with a removable transom, conveniently located to facilitate equipment entry and removal. In certain circumstances a second exit needs to be installed in the control house. The *National Electrical Safety Code (NESC)* states: "If the plan of the room or space and the character and arrangement of equipment are such that an accident would be likely to close or make inaccessible a single exit, a second exit shall be provided." The *National Electrical Code (NEC)* also defines specific requirements for a second exit. The doors should include locking devices, astragals to prevent water from entering, and adequate weatherstripping and hardware to permit a rapid exit from the control house.

Adequately ventilate the battery area, either by a natural or powered ventilation system, to limit accumulation of hydrogen gas to less than an explosive mixture. A powered ventilation system needs to be annunciated to indicate ventilation failure.

Provide portable or stationary water facilities or a neutralizing agent for rinsing eyes and skin in the battery area in addition to proper eye protection and clothing.

Locate and mark adequate fire-extinguishing equipment in the control house.

Windows can be provided, if desired, in office and lavatory areas. Battery rooms and control and metering areas do not need windows.

Consider adequate methods for building insulation. These methods include use of insulated wall panels, ceiling insulation, storm doors, and windows, and weatherstripping around all openings.

Metal buildings are shop painted and require only minor field touch-up after erection. Masonry buildings may be left unpainted or may be painted with portland cement or latex paint. Tint all prime coats to match the finished coat.

16.3   CONTROL HOUSE LAYOUT

16.3.1   Control and Relay Panels

Most relaying, metering, and control equipment is mounted on fabricated control and relay panels installed within the control house. A variety of panel types is available to suit individual requirements. Figures 16-4 and 16-5 show examples of various panel layouts.

Single vertical panels can be used, particularly for distribution circuits where space requirements are minimal. The relaying, metering, and control equipment can all be mounted on one panel, allocating a separate panel for each circuit. In some instances, two circuits may share the same panel.

Double or duplex panels are commonly used for higher voltage circuits, necessitating additional space for equipment mounting. Normally, these panels are arranged in two parallel rows with the panel backs facing each other. In this configuration, operating, instrumentation, and control equipment for a circuit is installed on the front of one panel, and the corresponding relaying equipment for the same circuit is

Figure 16-4: Typical Relay/Control Panel Layout.
Note microprocessor, electromechanical relays, and mimic bus.

Figure 16-5: 19-Inch Rack-Mount Relay/
Communications Equipment (PSI)

installed on the front of the panel directly to the rear. In some instances, two circuits may share the same control and relaying panels.

Some equipment such as static relaying systems and communications equipment is available mounted in racks. Consequently, separate relay and/or control panels are not required for this equipment.

Modern SCADA and substation automation schemes may require space for installation of a PC with monitor and keyboard, as well as programmable logic controllers and data highway interface modules. This equipment can often be rack-mounted or installed in control panels, as appropriate.

The trend is toward more compact equipment arrangements that often reduce overall control house size. Individual three-phase microprocessor relays can replace three single-phase electromechanical relays and associated voltage, current, and power meters, all in one case. Compact relay and programmable logic controller designs can be mounted on 48.26-cm (19-inch) racks.

To facilitate operation, panels are located in an arrangement that conforms as closely as possible to the actual equipment and circuit layout in the substation yard. To assist in circuit location and operation, mimic buses are sometimes used on the control panels, particularly for large complex substations. The mimic buses identify the bus and circuit arrangements. Mimic buses may be implemented on screens viewed from a PC monitor. When practical, position meters at eye level and switches at a convenient operating level. Locate recording meters for ease of viewing and chart replacement. Locate relays beginning at the tops of the relay panels and working downward. Relays with glass covers should not be located within 12 inches of the floor to avoid inadvertent breaking of the glass. Locate operating switches at convenient heights near the center of the boards. Require nameplates for all devices. Provide ample space for relay installation, removal, operation, and testing.

Panel construction can include removable front plates for device mounting. Panels may also include 19-inch rack mounting facilities. Many of the newer relays and items of accessory equipment are designed to fit into 19-inch racks. Cover plates may cover space reserved for future use. In this way, only a new predrilled plate is required when changing out a device or modifying the configuration. Cutting, drilling, or covering openings in the panels is eliminated.

Panel wiring is accomplished on the backs of the panels. Devices are interconnected and wired to terminal blocks, as required, for operation and connection to devices on other panels. Panels can include small sections perpendicular to the main section at each end for installation of terminal blocks, fuse blocks, or small auxiliary devices. Cable connections from the equipment in the substation yard can be made directly to terminal blocks mounted on the panels or to strategically placed terminal cabinets. Interconnections between the terminal cabinets and the panels can then be made with single conductor wire.

Anchor panels to the floor in such a way as to facilitate relocation to coincide with yard equipment and circuit relocations.

Panel arrangement in the control house should permit ready accessibility to the backs of the panels.

Some vendors of pre-engineered buildings can provide completely wired and tested control and relay panels and auxiliary ac/dc power systems as part of the building package. In this case, custom-designed relay and control schematics are submitted to the building vendor. The building vendor fabricates the panels, provides the relays and controls, wires the panels, and tests the complete installation. In this way, the entire panel line-up can be witness-tested in the factory. The complete building system is shipped to

the site, fully tested. Only the external wiring from the building to the outdoor equipment has to be field-installed.

16.3.2   DC Equipment

Substation dc equipment located in the control house normally consists of the battery, battery charger, monitoring and control devices, and distribution panelboard. The battery should be located in a separate room where practical. If the battery cannot be located in a separate room, it should be located so that electrical switching devices and receptacles are not in the immediate vicinity, ventilation is adequate to prevent gas accumulation, and live parts are protected from accidental contact. The battery charger, monitoring and control devices, and distribution panelboard are normally located in the control and relay room to facilitate cable routing and equipment maintenance.

Detailed design requirements and procedures for the substation dc system can be found in Chapter 15.

16.3.3   AC Equipment

A low-voltage ac system is provided in the substation for lighting; convenience outlets; heating, ventilating, and air conditioning (HVAC) equipment; and miscellaneous control functions.

Strategically locate convenience outlets throughout the control house to provide adequate accessibility. Provide the workshop and testing area with a high-capacity ac source and a three-phase source.

An ac distribution panelboard located inside the control house is used to supply the indoor lights, convenience outlets, HVAC equipment, and other devices.

For greater reliability, two separate sources may be provided for the ac system service. These sources are often fed through a manual or automatic transfer switch so that ac system power can be restored if one source fails.

Chapter 15 contains additional information concerning design of the substation ac system.

16.3.4   Cableways

Cable routing can be accomplished by using any of several methods.

16.3.4.1   Cable Trenches: Cable trenches are formed into the concrete floor slab and are covered with metal plates. The covers should be flush with the finished floor when in place. The sizes and locations of the cable trenches are based on the quantities of cables and locations of panels and equipment to be interconnected. Usually, a cable trench is located adjacent to the backs of the control and relay panels to facilitate panel interconnections. With duplex panels, it may be desirable to use the entire space between the front and rear panels as cable trench, depending on circuit quantities.

16.3.4.2   False Floors: False floors are useful when large open areas are desirable for cable routing. Lightweight removable floor panels installed on adjustable pedestals are positioned in areas requiring extensive cable interconnections or where future plans dictate a large amount of cable rerouting. The top of the removable panels should be flush with the finished floor.

When cables are mounted under false floors, establish routes and paths in which cables should be routed. This will allow the separation of circuits as required to maintain system reliability based on duplicate circuits. If circuits in one area are damaged, other undamaged circuits in the other parts of the building are likely to keep the substation in service.

16.3.4.3   Conduits: Conduits can be used for cable routing in floors, along walls, and for cable entrance into the control house.

Conduits are available in plastic, aluminum, and steel. Each of these types may be used in control houses for wire containment to convenience outlets, lighting fixtures, and other control house auxiliary power equipment.

Plastic conduit is easily installed and is available in a variety of sizes. Take adequate physical and thermal precautions when using plastic conduit to ensure safe operation.

Metallic conduits of aluminum and steel are widely used as control house cableways. Intermediate- and heavy-walled steel conduit provide excellent physical protection. The installed costs, however, may be relatively high because of the extensive labor required for installation. The installed cost of rigid aluminum conduit may be somewhat less than that for steel. A lower installed cost may be realized by using thin-walled steel conduit (i.e., electrical metallic tubing) since it is less expensive and easier to install.

16.3.4.4   Wireways: Wireways are sheet-metal troughs used for routing groups of power circuits around a control house to feed various branch circuits. Conduit is used between the wireway and the devices.

Wireway offers the advantage of laying rather than pulling the cable into position and the ability to change or reroute circuits easily. Wireway is available with hinged or removable covers in a variety of lengths and sizes. Select and install wireway in accordance with the *National Electrical Code*.

16.3.4.5   Cable Trays: Cable trays can be used for overhead routing of cables to and between control and relay panels. Expanded metal or ladder-type trays provide the best facilities for conductors entering and leaving the trays. An advantage of cable trays is the ability to lay rather than pull in the conductors. Suspended cable trays, however, prevent extensive use of this technique because of support locations. A large variety of types, sizes, and fittings is available to suit individual requirements. Cable tray should be selected and installed in accordance with the *NEC* and NEMA Standards.

16.3.5   Cable Entrance

Control and power cables are brought into the control house through windows, sleeves, or cable pits. The windows are square or rectangular openings, usually through the foundation wall but possibly above grade. The window openings enable many cables to be pulled without interference. To protect the cables during pulling, the windows should have smooth surfaces and beveled or rounded edges. After cable pulling, split sleeves can be installed around the cables and grouted into place. Occasionally, the windows are left open to facilitate future cable installation. Heat loss through these openings should be considered. Provide additional windows for installation of future cables. The windows can be constructed and bricked up to be opened when required.

Cable sleeves can be used above or below grade. The sleeves are usually cast into place during construction of the foundation wall or installed during construction of the superstructure. Pitch the

sleeves to drain out of the building. Provide covers over the cables. Install spare sleeves during initial construction.

Cable pits may be cast-in-place concrete or masonry openings through the control house foundation to permit access to the inside at floor level. Install a cover over the pit and provide a means to drain water.

16.3.6 <u>Lighting</u>

Fluorescent lamps are generally used for lighting in control houses. The trend is toward energy-saving lamps and energy-saving electromagnetic or electronic ballasts. Install lighting to eliminate, as much as possible, reflection and glare from meters, relays, and monitoring screens.

An emergency dc-operated incandescent system is recommended for most control houses. This system can be operated in case of failure of the ac system. It can be operated from battery-pack units or from the station battery system.

Additional information concerning control house lighting can be found in Chapter 15.

16.3.7 <u>Control House HVAC Systems</u>

To maintain the functions and accuracy of electrical equipment installed in the control house, HVAC systems may be desirable.

In areas requiring heat only, unit electric space heaters are positioned throughout the control house for balanced heating. If both heating and cooling are required, electric heat pumps can be used. Several small units, or one large unit with a duct system for air distribution, can be used. Supplemental electric resistance heating coils may be required for heating in colder areas.

Baseboard radiation heating units can be used in rooms not reached by the main heating system. These rooms include offices, lavatories, and storage rooms. The battery room is sometimes left unheated; however, maintenance of battery temperature close to $32^{o}C$ ($77^{o}F$) will prolong the life and capacity of most battery systems.

Temperature control levels may vary because of several requirements. Operating ranges of equipment have to be considered as well as economics. It is recommended that consideration be given to a dual control. Most stations will be unattended and, therefore, a normal personal comfort level is not required. However, for maintenance reasons, comfort levels are necessary.

The system then would normally maintain a minimum level based on equipment requirements with controls designed so that one or more additional units are used to raise the temperature to a comfort level suitable for maintenance personnel. In smaller control houses, this may be accomplished during maintenance periods by raising the thermostat controlling a small system.

If the control house is to be heated only, it is usually desirable to install power ventilation equipment for air circulation. Size the system for three to five air changes per hour. Place power-operated, thermostatically controlled roof ventilators and manually operated wall louvers to achieve good air circulation. Position wall louvers so that equipment does not interfere with air circulation. Provide fusible links to close the louvers in case of fire.

It is advisable to provide ventilation that will maintain a positive pressure within the control house at all times to prevent dust from entering through doors and other openings, and prevent accumulation of combustible gases. If control house air conditioning is used to provide positive air pressure, then the vent should remain open and fan should run continuously. This also applies if the unit is a heat pump.

The isolated battery room should be equipped with a gravity roof ventilator to remove corrosive and combustible gases. Do not use power-operated roof ventilators.

16.3.8   Control House Plumbing

Control houses may require plumbing for stationary eyewash facilities. Additionally, very large, major locations may warrant a shower, lavatory, drinking fountain, and maintenance sink.

A water supply, when required, may be obtained from an existing system or a private well on the substation site. A well should be capable of supplying 22 liters/minute (5 gpm) at a minimum pressure of 172.4 kPa (25 psi).

Most substations with toilet facilities will require septic tank and drain field systems. These systems are designed and installed in accordance with local codes and regulations, obtainable through county health departments. Additional information can be found in the *Manual of Septic Tank Practice*.

Separation between a water well and a septic tank and drain field should be in accordance with local ordinances. In the absence of such information, provide a minimum of 15.2 meters (50 feet).

16.3.9   Communications

A commercial telephone is usually installed in the control house for external communications. Additionally, system telephones or voice channels over carrier systems may be used for system communications.

Larger installations may include substation automation systems or SCADA for remote control and monitoring of substation equipment.

For a detailed discussion concerning substation automation, see Chapter 14, and for a detailed discussion concerning substation communications, see Chapter 17.

16.4   REFERENCES

ANSI Std. C2, *National Electrical Safety Code (NESC).*

National Fire Protection Association (NFPA) Std. 70, *National Electrical Code*.

RUS Std. 1724E-400, "Guide to Presentation of Building Plans and Specifications."

U.S. Department of Health, Education and Welfare, Public Health Service, *Manual of Septic Tank Practice*, Publication No. 526.

CHAPTER 17
COMMUNICATIONS

17.1   INTRODUCTION

Since substations are part of large interconnected power systems, methods of voice and data transmission among the various system parts are necessary to maintain satisfactory operation and control. Communication systems are used in protective relaying schemes to initiate tripping control schemes of power circuit breakers; in supervisory control systems to operate remote equipment, for transmission of data indicating equipment status and system conditions, and for voice communications for system operation and maintenance.

Table 17-1 matches the various substation communication applications with their appropriate communication methods.

Table 17-1:
Substation Communication Methods vs. Applications

APPLICATIONS	METHODS					
	Power Line Carrier	Audio Tone	Microwave	Fiber Optics	Wire Line	Satellite (VSAT)
Relaying	Y	Y	Y	Y	Y	
SCADA / Automation	Y		Y	Y	Y	Y
Voice	Y		Y	Y	Y	
Telemetering	Y	Y	Y	Y	Y	

17.2   APPLICATIONS

17.2.1   Relaying

Many relay schemes now in use require information to be exchanged among all the terminals on a transmission line to effect high-speed tripping over 100 percent of the line. Since these terminals are often many miles apart, some form of two-way communication channel has to be established between them. The information to be transferred is relatively simple two-state data in most cases and can utilize the more basic forms of modulation.

17.2.2   SCADA

Most utilities have a centralized energy control center from which the electric power system is remotely operated. It is usually expected that circuit breakers and tap changers will be monitored and controlled, generation monitored and controlled, capacitor banks may be monitored and controlled, alarms reset, and miscellaneous other on/off-type functions effected over distances ranging from a mile or less to hundreds of miles.

The energy control center receives various types of data from the power system. This data includes breaker status, tap changer position, amps, volts, watts, VARs, and other quantities, both digital and analog. Again, the data travels over distances ranging from a few miles to several hundred.

In most modern energy control centers, the remote data monitoring and system control functions for substation applications are performed by a SCADA system. These systems consist of a central host computer system at the energy control center, referred to as a master station, and RTUs located in the substations. There is a trend toward increasing intelligence at the substation level (see Chapter 14, Substation Automation) where the traditional RTU is being replaced with IEDs in a LAN arrangement. Regardless of the level of intelligence resident at the substation level, some form of real-time communication is required between the master station and the RTU or remote electronics.

17.2.3   Telemetering

In some instances where a computer-based SCADA system is not available or justified, it is desirable to transmit discrete power system data from the substation to the energy control system in an analog format. For example, analog quantities such as amps, volts, watts, or VARs may be required to drive a remote readout or chart recorder. Likewise, discrete system status values such as breaker position may be required to drive a remote annunciator. In these cases a communication method is required that can directly accommodate analog signals that may include scaled milliampere or voltage, or frequency-shift audio.

17.2.4   Voice

Power system operation and maintenance require the use of voice communication for daily operation and functioning of the power network. Voice communications are required between fixed points of operation and for mobile maintenance crews. The transmission of voice signals may take place via cable, radio, or the power system itself. The transmission facilities may make use of either leased systems or cooperative-owned facilities.

17.3   METHODS

17.3.1   Power Line Carrier

Power line carrier, one of the more common communication means found in power systems in the past, is now being displaced in many applications with fiber optics. But power line carrier may still be used for relaying and voice applications, and lower speed data.

Carrier signal frequencies range from 30 kHz to 500 kHz and are coupled directly to the power line through a coupling capacitor, a device that frequently doubles as a relaying and/or metering potential source. The signals are transmitted at a relatively low power level, 100 watts or less, typically 10 watts, and hence do not radiate appreciably from the power line. They have to be received in a similar way through a coupling capacitor connected to a carrier receiver at the other end of the line. See Figure 17-1.

To confine the carrier signal as nearly as possible to one line section and to keep the signal from being effectively shorted through the high capacitance of the station bus and connected transformers, line traps are installed on the station side of the coupling capacitor to block the carrier signal.
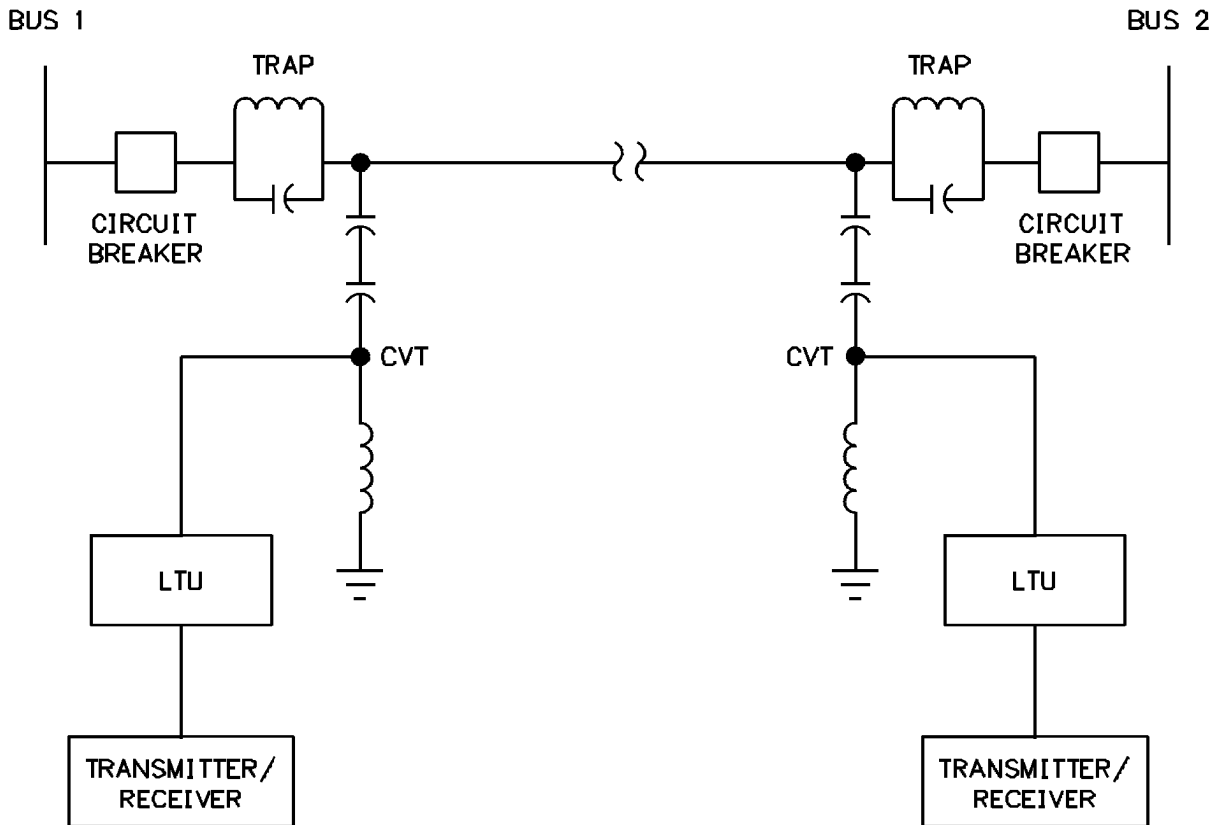
Figure 17-1: Typical Carrier System

Line traps are generally simple parallel L-C resonant circuits with the inductance in series with the coupled phase of the line. This inductance is rated to match the BIL, through current capability and short-circuit withstand capability of any other major equipment on the line, and so is physically large.

17.3.1.1 Tuning Elements: Besides the line trap and coupling capacitor, there are several other components involved in tuning and matching the transmitter output to the power system.

17.3.1.1.1 Line Tuner Unit (LTU): The coupling capacitor provides the path for the carrier signal to reach the power line itself. Since there are capacitive and inductive elements in the coupling capacitor and in the power system, a tuning network has to be provided to match the transmitter output impedance to the impedance seen at the coupling capacitor input. This device, the line tuner, comes in several different configurations, depending on the tuning method selected. In addition, the line tuner assembly contains protective elements such as a gap with capacitor and a grounding switch. The assembly may be mounted in the coupling capacitor base or in a separate weatherproof cabinet.

17.3.1.1.2 Hybrid: A hybrid is a special transformer used to combine carrier transmitter and receiver inputs and outputs in such a way that transmitters and receivers may be connected to the same line tuner without mutual interference. A hybrid has one output and two inputs and is bi-directional so that the output may be connected to the line tuner and the inputs to a combination of transmitters and receivers

without the receiver input being overloaded when the transmitter operates. Hybrids may be stacked; that is, one of the two inputs may be connected to another hybrid output resulting in three isolated inputs to the same line tuner. A limitation to this connection is that each hybrid reduces the power level by 3dB. Thus, two stacked hybrids result in only one quarter of the transmitter power reaching the line tuner from each hybrid terminal.

17.3.1.1.3 L/C Units: Various combinations of series and parallel connected capacitors and inductors are available for use with special tuning schemes or as additional tuning elements in the line tuner package. In general, the manufacturer's recommendations should be followed in applying these units.

17.3.1.2 **Tuning Methods:** There are three basic methods of tuning carrier transmitters and receivers to the power line.

17.3.1.2.1 Single-Frequency Resonant Tuning: A single-frequency resonant-tuned installation utilizes a combination of inductances and capacitances in the line trap and line tuner resulting in a combination frequency response that exhibits a single sharp peak centered about the selected frequency. Adjustment is available in both the trap and tuner, but both have to be ordered by specifying a range of frequencies according to the manufacturer's catalog data. Single-frequency resonant tuning is used less frequently as the available carrier spectrum becomes more crowded and it becomes more common to have several frequencies for multiple uses on a single line. Single-frequency tuning results in the lowest transmission losses, but is least flexible from the standpoint of subsequent additional carrier frequencies for control, telemetering, and relaying. Figure 17-2 shows a typical graph of the frequency response for a single-
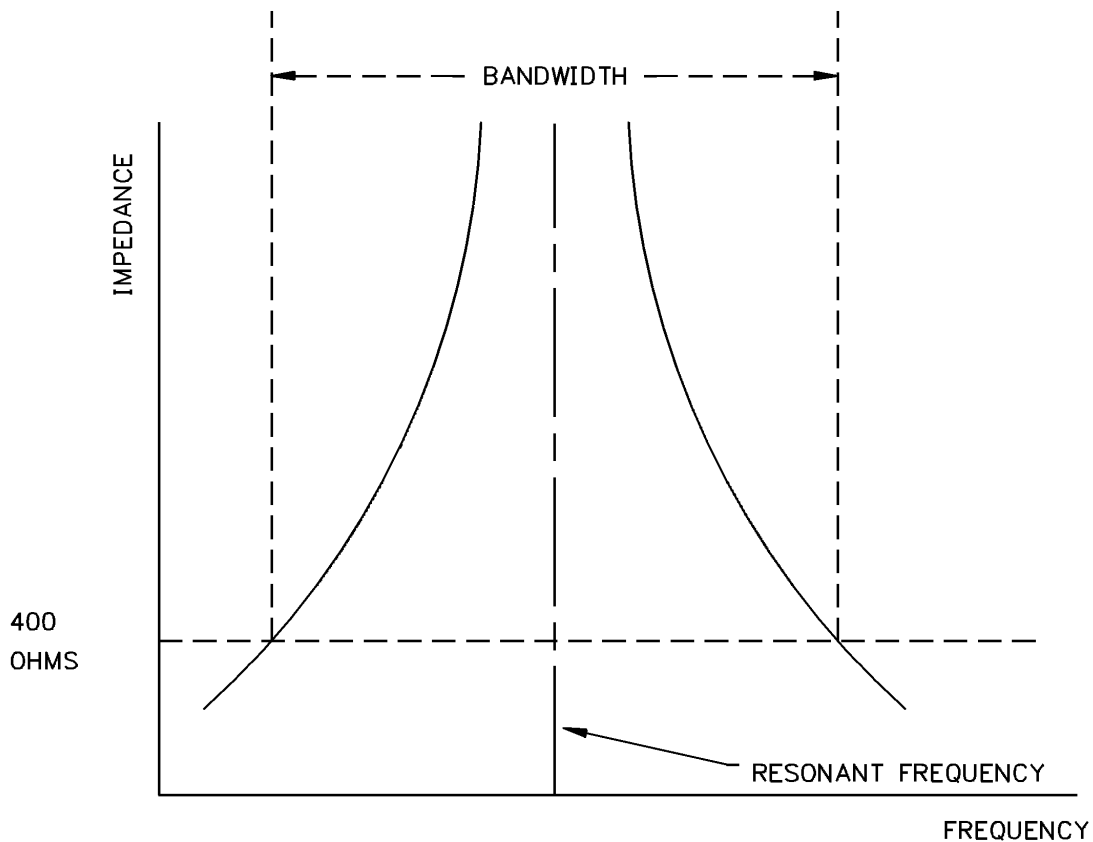
Figure 17-2: Single-Frequency Resonant Tuning

frequency resonant tuned installation.

17.3.1.2.2   Double-Frequency Resonant Tuning: This coupling method is identical to single-frequency tuning except that there are two closely spaced sharp peaks in the frequency response. The losses are somewhat greater, but the availability of two frequencies can compensate for this small disadvantage. In addition, it is possible to use as many as four frequencies if they are selected so that none is more than the manufacturer's tolerance away from a peak. This is done by using hybrids on each of the two frequencies. Figure 17-3 shows a graph of a typical double-frequency resonant-tuned system.
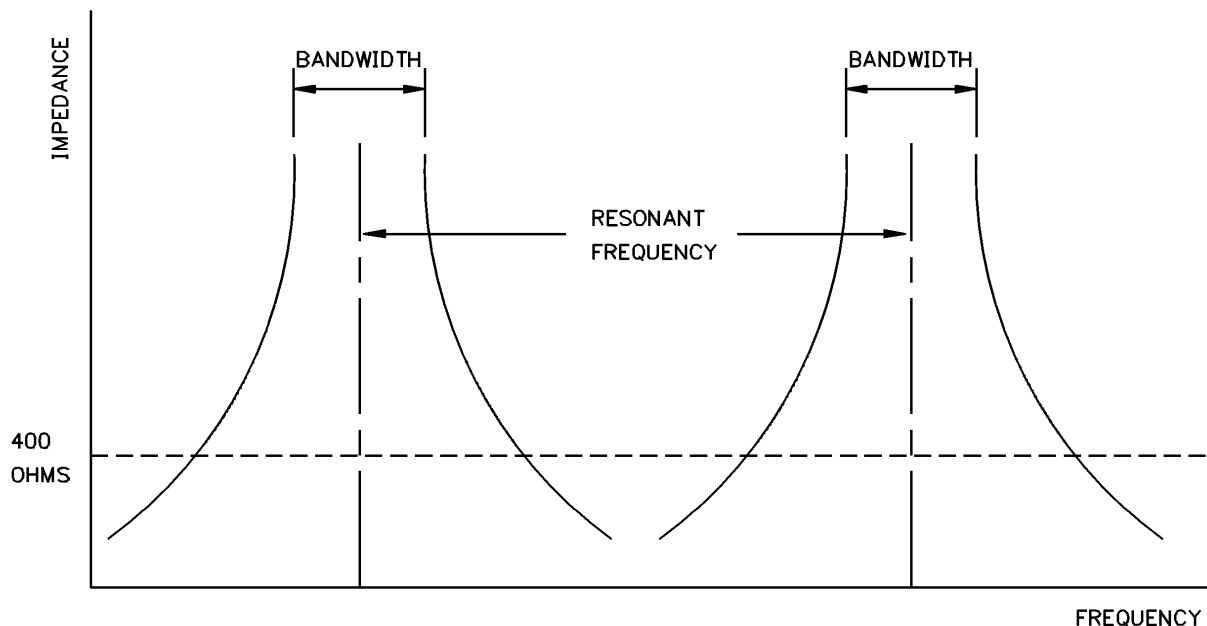
Figure 17-3: Double-Frequency Resonant Tuning

17.3.1.2.3   Wideband Tuning: The frequency response of a wideband tuning package is a relatively low peak spanning a wide range of frequencies. The obvious advantage is that a number of frequencies may be fed through the same line tuner.

A disadvantage is greater attenuation in the tuning package through more leakage to the bus side and higher impedance in the tuning package. The wideband line tuner is a simple high-pass filter, and series L/C units are frequently used to separate the various transmitter–receiver combinations. Hybrids should still be used to separate transmitters and receivers. Wideband tuning is becoming more popular in spite of the increased losses because of the need to put more functions on a line as relaying schemes become more elaborate and remote control and data functions are added. Figure 17-4 shows a graph of a typical wideband-tuned system.

17.3.1.3   Modulation Types

17.3.1.3.1   On/Off: This simplest form of putting information on the carrier wave is only used with directional comparison or phase comparison blocking relaying. As its name implies, the carrier transmitter is normally de-energized. When it is keyed, it simply sends an unmodulated carrier that the receiver interprets as a blocking signal. Voice modulators are usually added so that the transmitter carrier
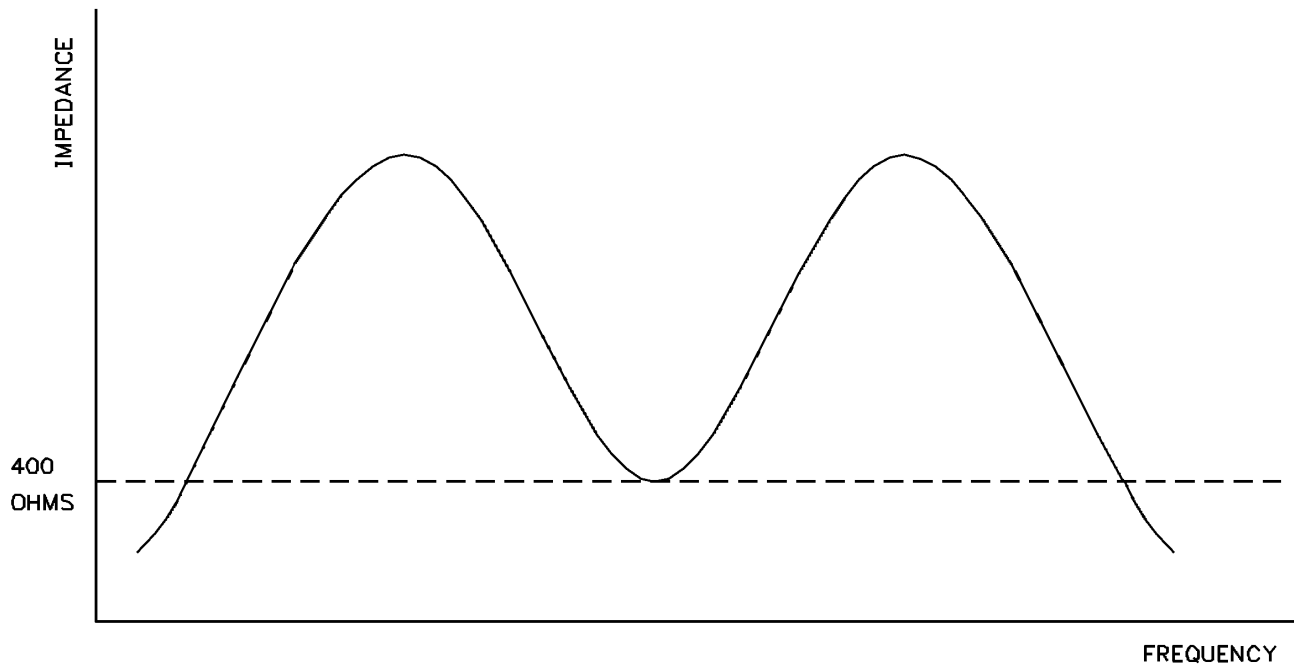
Figure 17-4: Wideband Tuning

can be modulated and thus provide an extra emergency or voice communication channel. Since a received signal in such a relay scheme does not result in a trip or attempted trip, it is perfectly safe to voice modulate the carrier.

The chief disadvantage of on/off carrier is its quiescent nature. The carrier is off most of the time and, if a component fails during this period, there will be no indication of the failure until the scheme is called on to operate. If it has to block for an external fault at that time, a false trip can occur. Many utilities avoid this situation by applying a carrier checkback scheme. This scheme periodically initiates a characteristic series of carrier bursts from one end of the line. The other end recognizes the test transmission pattern and responds similarly. Receipt of this response at the initiating end verifies the system can transmit and receive data.

17.3.1.3.2 Frequency Shift Keying (FSK): This modulation method finds widespread use in most relaying, control and data transmission schemes. An unmodulated carrier is sent continuously and is termed the "guard" or "space" signal. When a trip or data signal is desired, the guard or space signal is shifted up or down by a small percentage and the shifted signal is termed the "trip" or "mark" signal. In general, relaying literature uses the trip and guard nomenclature, while mark and space will be found in most data and control literature. Trip and guard signals are separated by very accurate filters on the inputs of the receiver.

The advantage of this scheme, particularly for relaying, is the channel monitor capability provided by the continuous transmission. If, at any time, the guard signal disappears without an immediate trip signal, the channel is presumed to have failed and an alarm can be energized. Additional channel security can be obtained by biasing the receiver discriminator to the guard side. A white noise burst, therefore, will produce a small net guard output that can be overcome by a transmitted trip signal even during the noise

burst. This feature makes it possible to drive an FSK carrier signal through an arcing fault on the protected section.

17.3.1.3.3   Single Sideband (SSB): This modulation type is used extensively in other countries where its multi-channel capability is important because of the lack of a reliable and extensive telephone network such as exists in this country. In those areas, power systems have to provide their own basic voice communications, and the power system itself is an excellent medium. Here, however, SSB carrier has found little use primarily because of its high cost.

Basically, the carrier signal is modulated with voice or data signals, resulting in the transmission of the carrier plus two sidebands containing the carrier plus the modulation frequency and the carrier minus the modulation frequency, which is conventional. Since all the desired information is in each sideband, the carrier and either sideband can be eliminated resulting in a suppressed carrier, single-sideband signal having one-half the bandwidth of a transmission. It is then possible to transmit two voice channels in the bandwidth formerly occupied by one voice channel.

Sophisticated equipment is available whereby, with a system of subcarrier frequencies, many channels in multiples of two can be transmitted.

17.3.1.4   **Power Line Carrier Reference:** The application of power line carrier is a complex subject requiring more space than is available in this bulletin. For a more thorough review of power line carrier application and design, see the following:

1.   "GE Protection and Controls Relaying Communication Channels Application Guide," GET-8034.

2.   Pulsar Technologies, Inc., "Power Line Carrier Channel & Application Considerations for Transmission Line Relaying," Pulsar Document No. C045-P0597.

17.3.2   Audio Tone

Audio tone equipment operates in the frequency range from 1000 Hz to about 3000 Hz. Frequency shift keying is the only modulation type available; voice modulation cannot be used.

Audio tone is used primarily as a short-distance medium over wire lines. FSK modulation provides ample security, and, in most cases for most telephone applications, reliability is also high. Additional security is available in the form of broadband noise detection and frequency translation detection.

Broadband noise detection is simply a wideband receiver with no corresponding transmitter. If this receiver output exceeds a certain level, a noise alarm is actuated and all channels squelched off. Frequency translation detection utilizes a single unmodulated channel. If the output from this receiver drops, the translation alarm is actuated. This feature is most commonly used with microwave or other multi-channel configurations where a problem in the multiplex equipment can cause frequency shifts.

Audio tone always requires another communication transmission medium to carry the audio (wire line, microwave, optical fiber, power line carrier, or shield wire).

17.3.3   Carrier or Audio Tone on Shield Wire

The chief distinction of this method is the medium rather than the equipment. Transmitters and receivers are the same as those employed in other carrier and audio tone systems. However, in this scheme they are coupled to insulated transmission line shield wires. EHV shield wires are sometimes insulated to reduce losses from induced circulating currents. The usual insulation level is 15 kV, with gaps on the insulators to conduct lightning strokes to ground.

The coupling is usually between two such insulated shield wires through a special coupler containing matching networks, capacitors, protective gaps, and an insulating transformer. This equipment is required to protect the communications equipment from the high energy levels present on such shield wires during lightning strokes.

In general, this method is not used for protective relaying because of the uncertainty of successful communication during lightning strikes. It has found more application for data and voice communications as a low-cost alternative in those cases where the decision to insulate the shield wires had already been made on the basis of inductive loss prevention.

17.3.4   Microwave

Microwave systems have been used extensively on power systems in the past few decades as the requirements for dedicated voice and data communications increase. Because of the high cost of the RF equipment and antenna towers, microwave is generally used where there is a requirement for a large number of channels between two points. Transmission is line of sight only, necessitating intermediate repeater stations for long paths. The cost per channel is relatively low as long as most of the available channels are used and the path length is not excessive.

Microwave systems presently employed use transmission frequencies of 960 MHz and higher, which accounts for the high channel capacity and line-of-sight transmission. There is relative freedom from many forms of interference, but path fading and other forms of distortion can be problems. Most microwave systems require a license from the Federal Communications Commission (FCC) to operate.

17.3.4.1   Analog vs. Digital Microwave: Both analog and digital microwave systems are in use today. Analog microwave systems accept audio input signals that are frequency multiplexed together to form an analog baseband signal that is then used to frequency modulate the higher frequency microwave carrier. Digital signals have to be converted to analog through the use of modems before they can be transmitted on an analog microwave system, which results in an inefficient use of the bandwidth. Analog microwave systems are available in capacities from as few as one to as many as 600 channels.

The increasing emphasis on data transmission is driving users toward increasing utilization of digital microwave. The majority of new microwave systems installed today are digital. Unlike analog microwave, digital microwave employs a digital time-division-multiplexed (TDM) baseband that is used to digitally modulate the microwave carrier. Analog (voice or audio) information is converted to a data stream using pulse-code modulation (PCM) and then fed into the microwave TDM baseband. Data signals ranging from low-speed asynchronous (1200 bits per second) to high-speed synchronous (56 kilobits/second, 1.5 megabits/second, and higher) can be inserted directly onto the TDM baseband without any intermediate modulation as would be required in an analog system. In this way, data is handled much more efficiently than in the analog scheme, and voice is handled equally well. This results in digital microwave systems having a lower per channel cost than analog. Digital microwave systems

are available in capacities from as few as one to as many as 2016 channels. Figure 17-5 shows a 6 GHZ digital microwave radio and antenna mounted on a substation box structure.

Figure 17-5: 6 GHz Microwave Terminal Mounted on Substation Box Structure

Power utilities typically purchase microwave radios in a monitored "hot-standby" configuration for added reliability. Hot-standby means that each radio contains two transmitters and two receivers, one set for primary and one set for backup, with monitoring and switching circuitry that automatically switches to the backup unit in the event the primary unit fails. For protective relaying on high-voltage transmission lines, it is common to use a microwave system in parallel with power line carrier for maximum security.

17.3.4.2   Multiple Address Systems: MAS are specialized microwave radio systems that are designed specifically for SCADA systems. MAS operate in the 900 to 960 MHz band and can employ analog or digital modulation technology. Each MAS provides a single channel of communications that is shared among four or more remote sites. The radio channel essentially behaves like a party line, so only one site can access the channel at any given time. Therefore, MAS is best suited to SCADA communications where a host computer sequentially polls remote terminal units using a master–slave protocol. This technology is widely used by electric utilities for substation SCADA communications in cases where other non-SCADA voice, data, and relaying applications are not needed. MAS is not suitable for telephone or protective relaying applications. Figure 17-6 shows a typical MAS installation on a rural substation control house.

Figure 17-6: MAS Microwave Antenna on Substation Control House

17.3.5   Optical Fiber

Optical fiber has become the communications technology of choice for most electric utility substation communications. Optical fiber offers the advantages of immunity to electrical sources of interference and noise, and extremely large information-carrying capacity. (The information-carrying capacity of optical fiber is far greater than that required in a typical substation.)

17.3.5.1   Fiber-Optic Cables: Fiber-optic cables are available in a variety of configurations including aerial and underground cables. Two of the most popular types of cable used by electric utilities are optical ground wire (OPGW) and all-dielectric self-supported (ADSS) cables. In the case of OPGW, optical fibers (numbering typically from 6 to 48 fibers) are placed inside a specialized conductor that serves as both a fiber-optic communications facility and a ground wire or shield wire. Since the shield wire is typically installed on the top of the transmission line towers above the energized line, ground clearance problems that often prevent the installation of a communications cable beneath the energized line (i.e., underbuild) are avoided. Also, for newly constructed lines, the incremental costs of a conventional shield wire (a cost that is avoided with OPGW) can be deducted from the costs of the OPGW, increasing the economic feasibility of the OPGW installation. Special suspension and termination hardware is required for the OPGW conductors. Figure 17-7 shows a typical OPGW splice mounted on an A-frame transmission structure.

ADSS cable finds its widest application by electric utilities on low-voltage distribution and subtransmission poles (69 kV or less), but can be also used on high-voltage transmission lines where clearances will allow. ADSS cables are self-supported, requiring no supporting messenger. The cables are all-dielectric (containing no metals) so they can be safely installed in the supply space on electric utility poles by properly trained line personnel, and they can be routed directly into an electrical substation from outside the substation ground mat without introducing a ground potential rise hazard. These cables can contain as few as 4 or as many as 216 fibers and can be manufactured for unsupported spans of up to several thousand feet.

Other cable types that are commonly used include aerial/duct cable (all-dielectric or steel-reinforced) and rodent-resistant cables for direct burial.

17.3.5.2   Fiber-Optic Technology: Fiber-optic transmission systems are primarily digital, utilizing TDM technology as is also used with digital microwave (see Section 17.3.4.1, Analog vs. Digital Microwave). Optical transceivers are available in capacities ranging from as few as one channel to many thousands. Fiber-optic transmission equipment from some manufacturers has been designed specifically for substation applications, supporting voice, data, and protective relaying functions. These specialized substation multiplexers are typically available at capacities of DS1 (1.544 megabits per second or up to 24 voice channels), SONET OC-1 (51.84 megabits per second or up to 672 voice channels), and SONET OC-3 (155.520 megabits per second or up to 2016 voice channels). These systems include advanced features such as embedded network surveillance, control, and management software, and fault-tolerant rings. Figure 17-8 shows fiber-optic multiplexers installed in a substation for telephone, SCADA, and pilot-wire relaying applications.

Another specialized application for optical fiber in substation communications is GPR isolation of metallic wire communications circuits. Because GPR can occur in electrical substations during short circuits on the electrical power system, metallic facilities such as telephone lines that enter the substation from outside the ground grid has to be electrically isolated from the substation ground influence. Since optical fibers do not conduct electricity, fiber-optic entrance links can be used to electrically isolate these metallic circuits in lieu of the more insulating transformers and mutual drainage reactors that have
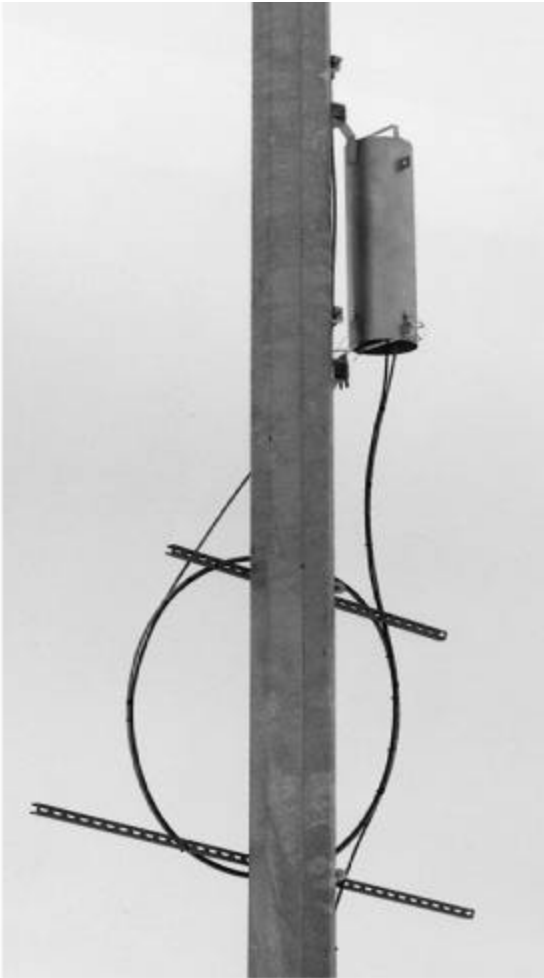
Figure 17-7: OPGW Splice on Deadend Structure
in Substation

Figure 17-8: Fiber-Optic Multiplexers (Above)
and Fiber-Optic Patch Panel (Below)

been traditionally used for this purpose. Special fiber-optic isolators are commercially available for this purpose.

17.3.6   Wire Lines

Wire lines leased from the telephone company are used in many cases for routine voice and data traffic. Wire lines entering substations for the purpose of communications, control, and protective relaying require special attention for high-voltage protection. These circuits may be used in the event of a power system fault; therefore, operation during these periods is crucial to personnel safety, equipment damage protection, and service reliability. The use of high-voltage protection aims to minimize the impact of GPR and induced voltages. Varying methods of protection are being used today. IEEE Std. 487-1992 states, "Readers of this standard should evaluate all alternative procedures, methods, voltage limits, and equipment characteristics for their own use." Section 6.0, Protection Apparatus, describes broad characteristics and application techniques of the current equipment in use today. The most common equipment used in wire-line protection ranges from carbon blocks, spark gaps, and gas-filled and solid-state protectors to the more advanced relays, filters, neutralizing transformers and reactors, isolating transformers, and the more recent use of optical couplers.

Section 8.0 of IEEE Std. 487-1992, Protection Theory and Philosophy, covers the different design and philosophical approaches the telecommunications protection engineer and the power protective relaying engineer may take in protecting telecommunications equipment. Section 8.2 of the standard covers design requirements for wire-line facilities serving power stations. Information on many factors is needed to properly design a protection scheme. A few of these conditions are:

1. Total available single-phase-to-ground fault current and its distribution, maximum GPR (rms), X/R ratio, fault-produced longitudinal induction, lightning exposure
2. Power station ground grid impedance to remote earth and grid area
3. The extent of the GPR zone of influence
4. Whether the transmission parameters and service performance objectives are compatible with the available or proposed facilities
5. Anticipated future changes in any of the above data
6. Whether lightning protection is required

Utilizing IEEE Std. 487-1992 is highly recommended for properly designing a protection system scheme. The system designs and protection concepts contained in this standard have been mutually agreed to by the power and telephone industries.

Wire lines entering substation premises have to have special protection against induced currents and rise in station ground potential.

17.3.6.1   Voice and Data Channels: These circuits may use carbon blocks or similar devices that will remove the circuit from service when they operate.

Voice traffic in most areas can be handled over wire lines since occasional interruptions can be tolerated in voice and data transmission. Relaying can be performed over wire lines only if the responsible telephone company can be relied on to provide circuits that are adequately protected against the effects of nearby power system disturbances.

17.3.6.2   Relaying Channels: These circuits have to remain in service during and after a power system fault. For audio tone circuits, fiber-optic isolators, high-voltage insulating transformers, gas tubes

with mutual drainage reactors, and possibly neutralizing transformers may be required. Pilot-wire circuits require neutralizing transformers whenever dc monitoring is used.

17.3.7   Satellite Communications

17.3.7.1   VSAT: Very small aperture terminals (VSATs) have been widely and successfully used for SCADA master station-to-RTU communications. VSAT networks optimized for SCADA are offered by network providers that sell the fixed transceiver equipment to the end user and then lease satellite airtime (space segment) on a monthly basis. Monthly charges are based on the amount of data that is actually transmitted by each VSAT. SCADA VSATs are most commonly used by electric utilities and pipeline companies that have to communicate with RTUs over very large areas where leased telephone line and private communication network costs are prohibitive. Electric cooperatives are probably the largest users of satellite communications in the electric utility industry today.

Since the VSAT space segment is leased, and therefore entails recurring monthly costs, VSATs are generally regarded as an alternative to leased telephone lines. VSATs do offer certain advantages over leased lines, insofar as they are not prone to outage resulting from wind, ice, or lightning. Since VSATs are wireless, they do not require high-voltage isolation as do leased telephone lines entering substations. VSATs can experience path outages during extremely heavy rainfall. VSATs also suffer outages around the spring and fall equinoxes, although these times are predictable and total equinox outage time is generally only 1 to 2 hours per year.

VSAT network vendors also offer advanced network management services that are not available for leased telephone lines. Since all signals pass through the vendor's hub facility, the vendor can carefully monitor channel performance and make maintenance adjustments when necessary.

Each message transmission between a master station and an RTU has to make two round trips to the geostationary satellite via the vendor's hub. Since each round trip requires at least 0.239 seconds to complete, the space segment delay for a single message is approximately 0.5 seconds. For this reason, inefficient SCADA master station-to-RTU communication protocols can result in the introduction of considerable communications delays.

VSATs should only be employed for data applications such as SCADA, and where relatively long time delays can be tolerated. VSATs are not considered suitable for voice or protective relaying applications.

In the early 1990s the Rural Electric Research (RER) Program of the National Rural Electric Cooperative Association (NRECA) initiated a project with the Electric Power Research Institute (EPRI) to develop a cost-effective Utility Communications Architecture-compliant satellite technology for rural utility substations.

The project was developed by Nova-Net Communications, Inc., now an ICG Wireless Services Company. The results of this project are documented in the final report of Project 91-10, "Bi-Directional Satellite Communications Technology for Rural Utility Substations."

Figure 17-9 shows a typical Nova-Net VSAT installation in a rural substation.

Figure 17-9: VSAT Installed in Electric Substation. Courtesy of Nova Net, Inc.

17.4   REFERENCES

ANSI/IEEE Std. 802.3, "Information Technology—Telecommunications and Information Exchange between Systems—Local and Metropolitan Area Networks—Specific Requirements—Part 3: Carrier Sense Multiple Access with Collision Detection (CSMA/CD) Access Method and Physical Layer Specifications."

ANSI/IEEE Std. 802.3v, "Information Technology—Local and Metropolitan Area Networks—Part 3: Carrier Sense multiple Access with Collision Detection (CSMA/CD) Access Method and Physical Layer Specifications, Informative Annex for Support of 150 ohm Cables in 10 BASE-T Link Segment."

ANSI/TIA/EIA- 232 E, "Interface Between Data Terminal Equipment and Data Circuit-Terminating Equipment Employing Serial Binary Data Interchange."

ANSI/TIA/EIA- 310-D, "Racks, Panels, and Associated Equipment."

ANSI/TIA/EIA-422, "Electrical Characteristics of Balanced Voltage Digital Interface Circuits."

ANSI/TIA/EIA-568-A, "Commercial Building Telecommunication Wiring Standard."

BELLCORE/GR-253-CORE, "Synchronous Optical Network (SONET) Transport Systems: Common Generic Criteria."

BELLCORE/GR-1230-CORE, "SONET Bi-directional Line-Switched Ring Equipment Generic Criteria."

BELLCORE/GR-1400-CORE, "SONET Dual Fed Unidirectional Path Switch Ring (UPSR) Equipment Generic Criteria."

BELLCORE/TR-TSY-000191, "Alarm Indication Signals Requirements and Objectives."

General Electric, "GE Protection and Controls Relaying Communication Channels Application Guide," GET-8034, Malvern, Pa.: General Electric, 1993.

IEEE Std. 487, "IEEE Recommended Practice for the Protection of Wire Line Communication Facilities Serving Electric Power Stations."

ITU-R/RECMN V.35, "Data Transmission Using 60-108 kHz Group Band Circuits—Data Communication Over the Telephone Network."

Miriam, Bob, P. Sanders, and Roger E. Ray, "Power Line Carrier Channel & Application Considerations for Transmission Line Relaying." PULSAR/C045-P0597, Coral Springs, Fla.: Pulsar Technologies, 1997.

NRECA/CRN "Bi-Directional Satellite Communications for Rural Utility Substations," Project 91-10, December 1995.

APPENDIX I TO CHAPTER 17
GLOSSARY OF TERMS

All-Dielectric Self-Supporting (ADSS): ADSS cables are self-supported, requiring no support messenger. The cables are all dielectric (containing no metals), so they can be safely installed in the supply space on electric utility poles.

Asynchronous Transfer Mode (ATM): A communications transmission and switching standard for carrying broadband signals at speeds of up to 2.2 gigabits per second. Combines techniques of time division multiplexing and packet switching.

Basic Impulse Insulation Level (BIL): A rating level to determine how insulating materials react to impulse voltages. As BIL increases, so does the amount of insulation required to protect the equipment.

DS1: Digital Signal Level 1; the designation given to a digital hierarchy of circuits or channels operating at 1.544 Mbps; commonly referred to as T1.

EHV: Extra high voltage; usually ranges from 345 kV to 765 kV.

Federal Communications Commission (FCC): A board of commissioners appointed by the President who have the power to regulate non-federal communications systems.

Frequency Shift Keying (FSK): Modulation type used in short-distance wire-line communications.

Ground Potential Rise (GPR): A phenomenon that occurs when there is a high-voltage difference between a grounded communications site and a distant site connected by wire-line communication circuits that has the potential to damage communication equipment.

Intelligent Electronic Devices (IEDs): Electronic equipment that provides monitoring and controlling capabilities.

kHz: Kilohertz; one thousand cycles per second.

Line Tuner Unit (LTU): A tuning network used to match the transmitter output impedance with the impedance seen at the coupling capacitor input.

Multiple/Address System (MAS): Radio system using master–slave protocol to communicate to a minimum of four remote computers.

MHz: Megahertz; one million cycles per second.

OC-1: SONET optical carrier 1, operating at data rate of 51.84 Mbps.

OC-3: SONET optical carrier 3, operating at data rate of 155.52 Mbps.

Optical Ground Wire (OPGW): Optical fibers (numbering typically from 6 to 48 fibers) placed inside a specialized conductor that serves as both a fiber-optic communications facility and a ground wire or shield wire.

Pulse Code Modulation (PCM): A scheme of transmitting data by digitizing and then using pulse codes to transmit the digitized data.

Remote Terminal Unit (RTU): An electronic device used to control and monitor Input/Output points, within an overall system and to communicate the derived data to a master station or other "host" unit.

SCADA: Supervisory Control and Data Acquisition; used by utilities and other process-oriented operations to collect data from machinery that may be spread over a very large geographic area. A basic SCADA system consists of two types of devices: master and remote. The master resides at a centrally manned location while the remotes are generally placed at unmanned locations. Communication between master and a number of remotes can be via telephone-like circuit, radio channels, or fiber-optic communications media.

SONET: Synchronous Optical Network; standard for optical transport formulated by the Exchange Carrier Standards Association (ESCA) for ANSI; essentially a standard for Broadband Integrated Services Digital Network transmission facilities.

Time-Division Multiplexing (TDM): A method of transmitting several signals on a single line on a time-sharing basis.

**CHAPTER 18
INSPECTION**

18.1   PURPOSE

Guidelines for the required inspection procedures for substation equipment, structures, and other devices discussed in this chapter are necessarily general. They have to be tailored to meet the requirements of a specific site as well as for the equipment at this site.

For additional information and references, see International Electrical Testing Association (NETA) *Acceptance Testing Specifications* and *Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems*.

In all cases, specific equipment manufacturers' recommendations, as contained in the equipment instruction books, should be observed and factored into the procedure as outlined. All inspections and tests should also be performed in accordance with applicable codes and standards including those of the *NEC*, ANSI, IEEE, NFPA, NEMA, and OSHA.

Perform certain test and maintenance procedures as the inspections are made. Therefore, coordinate the recommendations with those contained in the chapters covering testing (Chapter 19) and maintenance (Chapter 20).

18.2   GENERAL

It is essential that inspections of substation equipment, structures, and other devices be made periodically. In addition to this periodic inspection, other inspections may be required to ascertain the cause of particular problems, when equipment is placed in service, or when the substation, or portions thereof, are taken out of service.

18.2.1   Records

Maintain a record system for each substation site. This record system should at least provide the following information.

18.2.1.1   Equipment Records : These include equipment nameplate data together with specific transformer or voltage regulator tap connection details, trip settings, etc., for all equipment.

18.2.1.2   Inspection Records: These records, when accurately maintained, permit evaluation of the serviceability of equipment to be made at any time.

18.2.1.3   Inspection Checklist: This list, derived for a specific substation, contains all items to be inspected during periodic inspections.

18.2.2   Safety

So that all inspection procedures may be fulfilled safely and properly, it is essential that all personnel be thoroughly trained in proper and safe procedures. This includes but is not limited to the following:

1. Familiarity with operating procedures for the substation.

2. Familiarity with the applicable safety rules and regulations such as, but not limited to, the following:

    a. ANSI C2, *National Electrical Safety Code*
    b. OSHA 29 CFR 1910, Subpart S, Electrical Safety Related Work Practices
    c. OSHA 29 CFR 1910.269, Electric Power Generation, Transmission and Distribution
    d. OSHA 29 CFR 1910.137, Electrical Protective Equipment
    e. OSHA 29 CFR 1926, Subpart K, Electrical Safety Related Work Practices
    f. Applicable state and local safety operating procedures
    g. The cooperative's safety practices

3. Familiarity with protective and interlocking schemes.

4. Knowledge of the capabilities of the equipment.

5. The proper use of safety equipment.

6. The knowledge and proper use of first aid procedures and equipment.

7. The knowledge and proper use of equipment grounding techniques.

8. The prompt repair of any defects or improper conditions as soon as possible after they are noted.

9. Observation of safety regulations at all times. Proper distances have to be maintained from energized equipment. See the following standards as guidelines for the minimum clearance distances that have to be maintained between personnel and energized equipment:

    a. ANSI C2, *NESC*, Sections 43-44
    b. OSHA 29 CFR 1910.333, Selection and Use of Work Practices

10. Use of proper safeguards such as danger signs, temporary barriers, etc., for the safety of persons close to, but not engaged, in the work to be performed.

18.3   PERIODIC INSPECTIONS

The substation in total and the individual items of equipment contained therein should be periodically inspected. The recommended frequency of these inspections is as follows:

1. Visual inspection of total substation - monthly
2. Inspection with diagnostic online test equipment - annually
3. Detailed inspection of major equipment - annually
4. Internal inspection of transformers and regulators – as required

The recommended frequency may be varied if the cooperative has a reliability-centered maintenance program in place. See Chapter 20 for further information.

18.3.1   Visual Inspections

Visual inspections should encompass the total substation area including the site, the control house, and all equipment and structures. Make this inspection with the substation energized. Therefore, make all inspections from ground level to ensure adequate safety clearances from energized parts. Use binoculars to view buses and other equipment located on structures.

Use special care when ground connections are checked, since a high voltage could develop across any gap created between a ground cable and a piece of equipment, particularly under fault conditions. For this reason, do not remove ground connections for any reason while the substation is energized.

The following describes details of visual inspection.

18.3.1.1   Power Transformers

1.   Inspect the control cabinet, control relays, contactors, indicators, and the operating mechanism.

2.   Look for loose, contaminated, or damaged bushings; loose terminals; and oil leaks.

3.   Check oil levels in main tanks, tap changer compartment, and bushings.

4.   Inspect the inert gas system (when applicable) for leakage, proper pressure, etc.

5.   Read and record the operations counter indicator reading associated with the load tap changer.

6.   Observe oil temperature. Oil temperature should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40°C) plus 10°C. Generally, oil temperature does not exceed 95° and 105°C for 55° and 65°C winding temperature rise units, respectively, since the ambient temperature rarely exceeds 30°C for periods long enough to cause an oil temperature rise above these points.

18.3.1.2   Voltage Regulators

1.   Perform the same inspections as listed for power transformers (as applicable).

2.   Place the regulator control in the manual position and operate the regulator over a small range only.

3.   Return the control to automatic and verify that the regulator operates to return the output voltage to normal.

4.   Read and record the operations counter indicator reading.

18.3.1.3   Oil, Vacuum, SF$_6$ and Air Blast Circuit Breakers

1.   Check for loose, contaminated, or damaged bushings; loose terminals; oil leaks; and proper gas pressures.

2. Check the oil level in bushings and the main tank (if applicable).

3. Check the anti-condensation heaters.

4. Read and record the number of operations indicated. If the breaker has not operated during the preceding year, bypass the breaker or otherwise take it out of the circuit for testing. Test the breaker by simulating relay action by placing a jumper across the tripping contact studs on the back of the relay. Allow the breaker to go through its sequence to check its operation.

5. Inspect contact areas on the main plug-in assembly for signs of overheating or arcing.

6. Read and record compressor operating hours as shown on the indicator.

18.3.1.4 Fuses

1. Observe the condition of the contact surface of fuse clips.

2. Check for broken or cracked supporting insulators and for contamination.

18.3.1.5 Surge Arresters

1. Check for cracked, contaminated, or broken porcelain; loose connections to line or ground terminals; and corrosion on the cap or base.

2. Check for pitted or blackened exhaust parts or other evidence of pressure relief.

3. If discharge counters are provided, check connections and record the number of operations.

18.3.1.6 Buses and Shield Wire

1. Inspect bus supports for damaged porcelain and loose bolts, clamps, or connections.

2. Observe the condition of flexible buses and shield wires.

3. Inspect suspension insulators for damaged porcelain (include line entrances).

18.3.1.7 Capacitors (Series and Shunt)

1. Observe the condition of fuses.

2. Inspect for damaged tanks and bushings and for leakage of the dielectric.

18.3.1.8 Reactors (Oil Filled and Air Core)

1. Observe the condition of paint and varnish.

2. Inspect bushings for cracks and contamination.

3. Check valves and gaskets for oil leaks (if applicable).

18.3.1.9   Disconnects and Other Switches

1.   Check for cracked, contaminated, or broken porcelain; loose connections; and corrosion to metal parts.

2.   Observe the condition of contact surfaces and the area around them.

3.   Observe the condition of arcing horns on air break switches (when applicable).

4.   Inspect the operating mechanism.

5.   Inspect all live parts for scarring, gouging, or sharp points that could contribute to radio noise or corona.

6.   Inspect flexible braids or slip-ring contacts used for grounding for corrosion wear or broken strands.

7.   Check gearboxes for signs of moisture or corrosion.

8.   Check corona balls and rings for damage.

18.3.1.10   Control and Metering Equipment

1.   Check current and potential transformers for damage to cases, bushings, terminals, and fuses. Verify the integrity of the connections, both primary and secondary.

2.   Observe the condition of control, transfer, and other switch contacts; indicating lamps; test blocks; and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.

3.   Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.

4.   Open and close each potential switch on the test block to determine whether the speed of the meter disk is affected. Repeat the process with the current switches. Changes of speed should be approximately the same for each meter element.

5.   Check the status of relay targets (where applicable).

6.   Make an external examination of relays, looking for damaged cases and covers or loose connections.

7.   Check the station battery for loose connections and battery cells for low level or low specific gravity of the electrolyte. Record the electrolyte temperature.

8.   Inspect the station battery charger. Check the charging current and voltage. Observe the ground detector lamps for an indication of an undesirable ground on the dc system.

9.   Check the annunciator panel lights.

18.3.1.11   Structures

1.   Inspect all structures for loose or missing bolts and nuts.

2.   Observe any damaged paint for galvanizing or signs of corrosion.

3.   Inspect for deterioration, buckling, and cracking.

18.3.1.12   Grounding System

1.   Check all above-grade ground connections at equipment, structures, fences, etc.

2.   Observe the condition of any flexible braid type connections.

18.3.1.13   Cable

1.   Inspect exposed sections of cable for physical damage.

2.   Inspect the insulation or jacket for signs of deterioration.

3.   Check for cable displacement or movement.

4.   Check for loose connections.

5.   Inspect shield grounding (where applicable), cable support, and termination.

18.3.1.14   Foundations

1.   Inspect for signs of settlement, cracks, spalling, honeycombing, exposed reinforcing steel, and anchor bolt corrosion.

18.3.1.15   Substation Area (General)

1.   Verify the existence of appropriate danger and informational warning signs.

2.   Check indoor and outdoor lighting systems for burned-out lamps or other component failures.

3.   Verify that there is an adequate supply of spare parts and fuses.

4.   Observe the condition of hook sticks.

5.   Inspect the fire protection system and the provisions for drainage in the event of leaking oil.

6.   Check for bird nests or other foreign materials in the vicinity of energized equipment, buses, or fans.

7.   Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.

8.   Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.

9.   Inspect the area for weed growth, trash, and unauthorized equipment storage. . (See ANSI C2, *NESC* Rule 110B2 for information regarding storage).

18.3.1.16   Substation Fence

1.   Check for minimal gap under the fence or under the gate. A reasonable rule of thumb would be less than 2 inches under the fence and 4 inches under the gate.

2.   Ensure the fence fabric is intact and there is no rust.

3.   Check that the barbed wire is taut.

4.   Ensure the gate latches are operable.

5.   Ensure flexible braid-type connections are intact.

6.   Verify that no wire fences are tied directly to the substation fence.

18.3.2   Inspection With Diagnostic Online Test Equipment

Consider supplementing the visual inspections with the periodic use of diagnostic test equipment that allows more detailed inspection of the equipment while it is still energized. Some of these techniques are described below. Table 18-1, Substation Equipment Inspection Technology Matrix, lists equipment and what inspection technologies may be of value in identifying the condition of the equipment.

18.3.2.1   Infrared Thermography: Infrared thermography can provide a non-contact means of online evaluation of "hot spots" in an energized system. The infrared viewer provides a television-like image of the natural infrared energy being emitted from the objects in its field of view. The pictures, commonly referred to as thermograms, can be analyzed in real time or stored electronically and analyzed in the office or lab. When a loose or corrosive connection is present under loaded conditions, the infrared viewer can detect the temperature differential between the connection and the surrounding conductors.

When doing infrared scanning, the following test parameters need to be taken into account:

1.   Infrared scanning surveys should be done during periods of maximum possible loading, but not less than 40 percent of rated load of the electrical equipment being inspected. Refer to NFPA 70B, Section 18-16, Infrared Inspection.

2.   Inspect distribution systems with imaging equipment capable of detecting a minimum temperature difference of 1°C at 30°C.

A general outline for a thermographic survey follows.

Table 18-1: Substation Inspection Technology Matrix

Component Description	Infrared Therm.	Lab Oil Analysis	Ultrasonic Flow	Vibration	Ultra-sound	Recording Temp. Surveys	On-Site Oil Analysis	Visual
Generator Step-Up Transformer	X	X	X	X	X	X	X	X
Transmission Transformer	X	X	X	X	X	X	X	X
Step-Down Dist. Transformer	X	X	X	X	X	X	X	X
Current Transformer	X				X			X
Potential Transformer	X				X			X
Trans. Blower Motors	X	X		X	X			X
Trans. Oil Pumps	X		X	X	X			X
Trans. Coolers	X							X
Trans. Tap Changers	X	X				X		
Trans. Control Cabinets	X							X
Oil Circuit Breakers	X	X			X			X
Air Circuit Breakers	X				X			X
S.F.$_6$ Breakers								
DC Control Batteries								X
Trans. & Dist. Bus	X				X			X
Disconnects	X				X			X
Enclosed Switchgear	X				X			X
Ground Networks	X							X
Dist. Regulators	X	X				X	X	X
Light & Power Trans.	X							X
D.C. Control Bus	X							X
Fuse & Fuse Clip	X							X
Terminal Blocks	X							X
Enclosed Buswork	X				X			
Cable Splices	X				X			X
Reactors	X				X			X
Compressor Motors	X			X	X			X
Nitrogen Systems					X			
Motors	X			X	X			X
Lightning Arrestors	X				X			X
Carrier Current Wave Traps	X				X			X
Insulators	X				X			X
Batteries	X							X

THERMOGRAPHIC SURVEY

1. Inspection and Preparation of Equipment To Be Surveyed
   a. Inspection of physical, electrical, and mechanical condition of equipment
   b. Where applicable, removal of all necessary covers prior to thermographic inspection

2. Report Components
   a. Load conditions at the time of the inspection
   b. Hot spots
   c. Temperature difference between the area of concern (hot spot) and the reference area
   d. Cause of temperature difference
   e. Areas inspected, with inaccessible and / or unobservable areas and /or equipment identified
   f. Photographs and/or thermograms of the hot spot area

3. Test Results
   a. Temperature differences of 1°C to 2°C that indicate possible deficiency and warrant investigation
   b. Temperature differences of 4°C to 15°C that indicate deficiency and has to be repaired as time permits
   c. Temperature differences of 16°C and above that indicate major deficiency and has to be repaired immediately

18.3.2.2   Laboratory Oil Analysis: All oil-filled power transformers and circuit breakers generate gases during normal operation. But when the equipment begins to function abnormally, the rate of gas production increases. Analyzing these gases and their rate of production is another valuable tool for evaluating the condition of an operating transformer or breaker. Other tests can also be performed on the oil to determine the oil's condition. For additional information on oil analysis, see Chapter 19 of IEEE Std. C57.106, "Guide for Acceptance and Maintenance of Insulating Oil in Equipment."

18.3.2.3   Ultrasound: Another method for evaluating a system that is energized is the use of an ultrasound detector. Ultrasound is used to detect inaudible noises on equipment that could indicate potential problems. Listed below are some examples of what ultrasound can be used to detect.

1. **Bus:** When corona is present in medium- and high-voltage circuits, air is ionized. Corona emits a high-frequency pitch that can be heard with the human ear. However, the ultrasound detector can pinpoint low levels or corona not heard by the human ear and also at greater distances. Substations and transmission lines can be audibly inspected by this method to locate sources of corona. The ionized air generated by corona will attack insulation. The early detection of its presence can allow for corrective measures before further insulation deterioration occurs.

2. **Power Transformers:** Ultrasound can detect inaudible noises on transformer internals that could indicate arcing, sparking, partial discharge, combustible gases, corona, core looseness, vibration, or loose parts.

3. **Cooling Pumps and Fan Motors:** Ultrasound can also be used to evaluate the overall condition, and for cavitation and flow.

18.3.2.4   Portable Gas in Oil Analysis: This analysis measures the amount of dissolved combustive gases in transformer oil and/or hot metal gases in tap changer oil, which can be the evidence of arcing, sparking, partial discharge, corona, and/or overheating. This can be done in the field and can be used for trending and historical information. If there is a noticeable increase in the amount of dissolved combustive gases, a laboratory oil analysis should be done to determine the cause of the increase. See Chapter 19 for additional information on testing.

18.3.3   Detailed Inspection of Major Equipment

Annual inspections are recommended for certain major equipment and portions of the auxiliary system. These inspections are detailed and will therefore require that the piece of equipment being inspected be de-energized.

Annual inspections are recommended for the following equipment:

1.   Disconnects and other switches

2.   Metal-clad switchgear

3.   Air circuit breakers

4.   Oil circuit breakers

5.   Air blast and SF_6 circuit breakers

6.   Vacuum circuit breakers

The annual inspections should be conducted simultaneously with and in addition to the bi-monthly inspections suggested in Section 18.3. Details are described in the following sections.

18.3.3.1   Disconnects and Other Switches

1.   Inspect moving and fixed contacts. Verify the adequacy of the wiping action. Check contact pressures.

2.   Inspect the spring assembly for signs of corrosion (air break switches only) and tighten bolts.

3.   Inspect the current shunt around the spring assembly and tighten all bolts.

4.   Check the fluid levels in gearboxes (where applicable).

5.   Check the blade alignment on gang-operated switches.

6.   Inspect the switch base and other galvanized parts for signs of corrosion.

7.   Verify the correct operation and adjustment of motor-operated limiting switches and mechanical interlocks (where applicable).

8.   Perform a contact resistance test and compare it with the manufacturer's acceptable resistance values.

18.3.3.2 Metal-Clad Switchgear

1. Inspect for damage to enclosures, doors, latching mechanisms, etc.

2. Inspect bus supports for signs of cracking.

3. Verify that all joints are tight.

4. Check the alignment of all disconnect devices, both primary and secondary, including those for potential transformers.

5. Inspect terminal connections and the condition of wiring.

6. Check rails, guides, rollers, and the shutter mechanism.

7. Inspect cell interlocks, cell switches, and auxiliary contacts.

8. Inspect control, instrument, and transfer switches.

9. Inspect for broken instrument and relay cases, cover glass, etc, and check for burned-out indicating lamps.

18.3.3.3 Air Circuit Breakers (15 kV and Below)

1. Inspect contacts for visual signs of overheating. Check contact clearance, contact wipe, toggles, latches, position indicator, auxiliary contacts, etc.

2. Inspect hardware and check wire connections for secureness.

3. Inspect arc interruption chambers.

4. Inspect relay contacts.

5. Check fuse clips for secureness.

6. Check the condition of bushings, porcelains, and contact surfaces.

7. Check the load conductor terminations.

8. Check the current transformer connections.

9. Check the grounding connections.

10. Check the lifting or racking mechanism (if applicable).

18.3.3.4 Oil Circuit Breakers

1. Check compressor operation, including operation of all pneumatic switches and their operating set point.

2.   Check for air leaks.

3.   Check the compressor belts.

4.   Check the latching mechanisms, relay contacts, and fuse clips (for secureness).

5.   Untank the breaker and check.

6.   Check pole units, contacts, bayonets, interrupters, and resistors for signs of heating.

7.   Inspect the hardware and wiring connections for CTs.

8.   Inspect the alignment of contacts.

9.   Inspect the operating mechanism and leakage.

10. Inspect the lift rod and toggle assembly.

NOTE: Untanking is required only when specified in the manufacturer's instruction book. This is normally done after a trip operation when the magnitude of current interrupted approaches the maximum capability of the breaker or after a particular number of operations. In the latter case, the time of inspection should be coordinated with the annual inspection whenever possible.

CAUTION: Observe the manufacturer's recommendations with respect to manual operation of the circuit breaker without oil.

18.3.3.5   Air Blast and SF$_6$ Circuit Breakers

1.   Perform all checks and inspections as outlined in Section 18.3.3.4 for oil circuit breakers.

2.   Inspect the compressor system, including belts, pneumatic switches, contactors, relays, and other auxiliary devices.

3.   Inspect the gas or air piping for signs of deterioration.

4.   Inspect all air or gas seals and o-rings.

5.   Inspect the wiring connections and hardware for CTs.

18.3.3.6   Vacuum Circuit Breakers

Perform all checks and inspections as outlined in Section 18.3.3.3 for air circuit breakers except for all reference to inspection of main contacts or arc interruption chamber.

18.3.4   Internal Inspection of Transformers and Regulators

Internal inspections require considerable time out of service for the equipment involved. Therefore, they should be scheduled, whenever possible, to coincide with planned substation outages.

Since large equipment is frequently required for use in disassembly operations, it is essential that all aforementioned safety precautions be rigidly followed. Details of these inspections follow.

18.3.4.1   Transformers: Open-type transformers (those that may breathe free air) that have not been so inspected for at least three years should, if time permits, be given an internal inspection consisting of the following:

1.   Lower the oil level to expose the top of the core coil assembly.

2.   Look for evidence of corrosion of tank walls and other metal parts.

3.   Check connections for secureness.

4.   Check to see whether sludge deposits have accumulated in ducts or other locations. Such deposits impede the circulation of oil and thus any appreciable amount should be removed.

5.   Test samples of oil taken from the bottom of the tank to determine the water content. See Chapter 19, Testing.

18.3.4.2   Regulators: Inspect voltage regulators using the same criteria as indicated for open transformers. It may be necessary to untank the core and coil assembly to complete the inspection.

18.4   NON-PERIODIC INSPECTIONS

Whenever a substation, or any part of it, is de-energized for any reason, a detailed inspection should be made of those items of equipment that cannot be observed at close range when energized. In particular, this includes:

1.   Transformers
2.   Regulators
3.   Fuses
4.   Disconnects
5.   Air Break Switches
6.   Load Interrupter Switches
7.   Grounding System
8.   Circuit Breakers
9.   Oil Circuit Breakers
10.   Structures
11.   Buses

The extent of the inspections may be limited because of the time available during the period of de-energization. However, it is essential to perform as many items as possible. Details of the inspection procedures are outlined in the following sections.

18.4.1   Inspection of Porcelain

Inspect all insulators and equipment bushings for chipped petticoats and fractured or cracked porcelain. Flashovers in the past may have damaged a portion of the glazing on the porcelain. Make this inspection at close range.

18.4.2   Fuses, Disconnects, and Other Switches

Inspect current-carrying portions to verify that proper tensions are being maintained. Inspect contact surfaces for pitting, burning, alignment, and pressure. Replace badly pitted or burned contacts. See that all bolts, nuts, washers, pins, and terminal connectors are in place and in good condition.

18.4.3   Buses

Inspect all bus fittings, connectors, couplers, etc., to verify that all bolts are tight and that there is no indication of hot spots, as evidenced by discoloration. Also verify the integrity of the stranding of flexible buses at strain clamps.

18.4.4   Transformers

Check open transformers that have not been internally inspected for at least three years in accordance with details contained in Section 18.3.4, Internal Inspection of Transformers and Regulators.

18.4.5   Transformer On-Load Tap Changers

If the number of operations of the tap changer contactor is approaching mandatory inspection and possible replacement of the contacts in accordance with the manufacturer's recommendations, this inspection might best be performed at this time. In this case, the tap changer compartment has to be drained of oil. Inspect all portions of the mechanism for excessive wear and proper adjustment.

18.4.6   Regulators

Check voltage regulators that have not been internally inspected for at least three years in accordance with details contained in Section 18.3.4, Internal Inspection of Transformers and Regulators.

18.4.7   Oil Circuit Reclosers

Inspect these devices in accordance with the instructions in 7 CFR 1730, "Electric System Operation and Maintenance," and RUS Bulletin 1730-1, "Electric System Operation and Maintenance (O&M)."

18.4.8   Circuit Breakers

Inspect circuit breakers in accordance with the applicable procedures contained in Section 18.3.3 if they have not been so inspected within the previous 12 months.

18.4.9   Grounding System

Check all accessible ground connections for secureness, and measure the overall ground grid resistance if it has not been done for a number of years. Since it is desirable to disconnect shield wire grounds and system neutral connections to make this measurement, the total substation has to be de-energized for these tests. See Chapter 19, Tests, for details.

18.4.10   Structures

Inspect all structures in close proximity to buses, energized portions of equipment, etc., and make

necessary repairs to galvanizing and painted surfaces. See Chapter 20, Maintenance, for details.

18.5 REFERENCES

7 CFR 1730, "Electric System Operation and Maintenance."

ANSI Std. C2, *National Electrical Safety Code (NESC).*

IEEE Std. C57.106, "Guide for Acceptance and Maintenance of Insulating Oil in Equipment."

International Electrical Testing Association (NETA), *Acceptance Testing Specifications for Electrical Power Distribution Equipment and Systems,* 1999.

International Electrical Testing Association (NETA), *Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems,* 1997.

NFPA 70B, Section 18-16, "Infrared Inspection."

OSHA 29 CFR 1910, "Subpart S Electrical Related Work Practices."

OSHA 29 CFR 1910.137, "Electrical Protective Equipment."

OSHA 29 CFR 1910.269, "Electrical Power Generation, Transmission and Distribution."

OSHA 29 CFR 1926, "Safety and Health Regulations for Construction."

OSHA 29 CFR 1910.333, "Selection and Use of Work Practices."

RUS Bulletin 1730-1, "Electric System Operation and Maintenance (O&M)."

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**CHAPTER 19
TESTS**

19.1 GENERAL

Tests of substation equipment are required to fulfill at least the following functions:

a. To prove the integrity of a piece of equipment at the time of acceptance
b. At periodic intervals, to verify the continued availability of the equipment
c. At the time of failure of a piece of equipment, to be able to determine the specific requirements for repair

The types of tests to be performed for each of the above categories vary. Guidelines are therefore included to assist in this selection. The guidelines are, of necessity, quite general in nature and, as such, have to be tailored to meet the requirements of the specific equipment.

Coordinate the testing schedules with the inspections as detailed in Chapter 18. In addition, utilize scheduled outages to the greatest extent possible as periods for testing since certain equipment is unavailable for test unless large portions of the substation are de-energized.

Upon completion of tests, make provisions to follow-up with repeat tests where required and make repairs where the need is indicated by the test results.

In all cases, factor into the testing procedures outlined specific equipment manufacturer's recommenda-tions as contained in the equipment instruction books.

19.1.1 <u>Records</u>

Maintain a records system, as outlined in Chapter 18, Inspection, for each site. In addition to the details contained therein, these records should contain at least the following information:

a. The name, date, and results of all tests performed
b. The date when the equipment should again be tested
c. Any requirements for follow-up or special tests required as a result of indications of potential trouble

19.1.2 <u>Safety</u>

Some tests, particularly those requiring gas or oil samples, may be performed without removing the equipment from service. The personnel performing such tests or obtaining gas or oil samples have to observe safety regulations at all times. Special attention is called to the minimum clearances provided in Chapter 18. Whenever possible, provide temporary barriers to isolate the equipment being tested from adjacent energized equipment.

Testing equipment is usually very specialized. Restrict its use, therefore, to those personnel who have been adequately trained. Improper use of the equipment may expose both the user and the equipment to hazards.

The analysis of properly obtained test data is again a specialized technique. Failure to recognize trends while conducting a test could be injurious to the personnel, the test equipment, and the equipment being tested. Failure to recognize trends in data obtained at different times can result in the failure to detect potential problems in sufficient time to permit an orderly and timely removal of equipment from service.

19.2 DETAILED REQUIREMENTS

As indicated above, testing is performed to accomplish three distinct functions: the acceptance of equipment, the periodic verification of its integrity, and to permit better analyses of its failure.

19.2.1 Acceptance Tests

Acceptance tests are performed after receipt and erection or installation of equipment at a site. The results of these tests are compared with the specifications, where applicable, evaluated, and compared with acceptable norms and factory test data and, when found acceptable, recorded for future reference. The recommended acceptance tests, delineated by type of equipment, are indicated in Table 19-l.

19.2.2 Periodic Tests

Periodic tests, those used to establish the continuing quality of the equipment, are conducted at varying intervals, depending on the type of equipment. Table 19-2 provides a tabulation of the recommended periodically conducted tests together with the recommended interval between tests.

19.2.3 Tests After Failure

Testing conducted after an equipment failure is performed to determine, to the greatest extent possible, the location, magnitude, and cause of the failure. Such data, when properly obtained, is used in determining whether the equipment can be repaired in place or needs to be shipped to a repair shop. The tests to be performed in such cases are the same as listed in Table 19-2, except that high-voltage tests are not usually performed.

19.3 DESCRIPTION OF TESTS

Descriptions of the tests indicated in Tables 19-l and 19-2 are contained in subsequent paragraphs together with ranges of test values that are considered acceptable.

Specific details for application of the test equipment are in the instruction book for that item of test equipment. A brief reference to applicable test equipment is also included with the description of each test. The ranges and outputs indicated are considered appropriate for the tests and thus should not be varied significantly.

19.3.1 Insulation Resistance Test

This test is performed to verify the integrity of the insulation as is used in all types of electrical equipment. This includes transformers, circuit breakers, cables, motors, switches, etc.

19.3.1.1 **Equipment Required:** 500/1000/2500 volt "megger," either motor driven or voltage regulated.

Table 19-1: Acceptance Test Requirements

Required Tests ® / Items To Be Tested	Insulation Resistance Test	Power Factor Test	DC High Potential Test	Dielectric Absorption Test	AC Over-Potential Test	Winding Resistance Measurement	Insulating Oil Dielectric Strength	Insulating Oil Power Factor Test	Timing Test	Series Overcurrent Test	Turns Ratio Test	Polarity Test	Capacitance Test	Pressure Test of Piping and Receivers	Grid Resistance	Visual Inspection	Core-to-Ground Insulation Resistance Test
Transformer, Conservator Type	X	X		X		X	X	X			X	X				X	X
Transformer, Inert Gas Cushion Type	X	X		X		X	X	X			X	X				X	X
Load Tap Changer Mechanism		X					X	X								X	
Regulators		X		X		X	X	X								X	
Oil Circuit Breakers		X					X		X							X	
Air Circuit Breakers		X			X					X						X	
Vacuum Circuit Breakers		X							X							X	
SF$_6$ Circuit Breakers		X							X					X		X	
Air Blast Circuit Breakers		X							X					X		X	
PTs	X	X									X	X				X	
CTs	X	X									X	X				X	
CCPDs		X											X			X	
Surge Arresters		X														X	
Cable, 600 Volts	X			X												X	
Cable, 5 kV and Above	X	X	X	X												X	
Disconnects and Air Break Switches		X														X	
Vacuum Switches		X	X						X							X	
Circuit Switchers		X							X							X	
Capacitors													X			X	
Metal-Clad Switchgear	X	X	X	X	X											X	
Protective Relays	X			X												X	
Metering Equipment	X															X	
Substation Ground Grid															X	X	
Test Procedure or Details Outlined in Paragraph	19.3.1	19.3.2	19.3.3	19.3.4	19.3.5	19.3.7	19.3.8	19.3.8	19.3.11	19.3.13	19.3.14	19.3.15	19.3.18	19.3.19	19.3.20		19.3.1

Table 19-2: Periodic Test Requirements

Items To Be Tested	Insulation Resistance Test	Power Factor Test	DC High Potential Test	Dielectric Absorption Test	AC Over-Potential Test	Contact Resistance Test	Calibration Test	Insulating Oil Neutralization Number	Insulating Oil Interfacial Tension	Insulating Oil Dielectric Strength	Insulating Oil Color Test	Insulating Oil Visual Examination	Insulating Oil Power Factor Test	Insulating Oil Combustible Gas Analysis	SF_6 Gas Analysis	Timing Test	Motion Analyzer Test	Series Overcurrent Test	Turns Ratio Test	Capacitance Test	Grid Resistance	Visual Inspection	Core-to-Ground Insulation Resistance Test
Transformer, Conservator Type	12	12						12	12	12	12	6	12	6					24			2	12
Transformer, Inert Gas Cushion Type	12	12						12	12	12	12	6	12	6					24			2	12
Load Tap Changer Mechanism		12						12	12	12	12	6	12									2	
Regulators	12	12						12	12	12	12	6	12									2	
Oil Circuit Breakers		12				12		12	12	12	12	6	12			12	12					2	
Air Circuit Breakers		12			24	12										12		12				2	
Vacuum Circuit Breakers		12				12										12						2	
SF_6 Circuit Breakers		12				12									12	12						2	
Air Blast Circuit Breakers		12				12										12						2	
PTs		12																				2	
CTs		12																				2	
CCPDs		12																		12		2	
Surge Arresters		12																				2	
Cable, 600 Volts																						2	
Cable, 5 kV and Above		12	12	12																		2	
Disconnects and Air Break Switches		12				12																2	
Vacuum Switches		12	12			12																2	
Circuit Switchers		12				12																2	
Capacitors																				12		2	
Metal-Clad Switchgear	12	12	12		24																	1	
Protective Relays					24		12															1	
Metering Equipment							12															1	
Substation Ground Grid																						1	
Test Procedure or Details Outlined in Paragraph	19.3.1	19.3.2	19.3.3	19.3.4	19.3.5	19.3.6	19.3.17	19.3.8	19.3.8	19.3.8	19.3.8	19.3.8	19.3.8	19.3.9	19.3.10	19.3.11	19.3.12	19.3.13	19.3.14	19.3.18	19.3.20		19.3.1

NOTE: The number in the box indicates the amount of time in calendar months between periodic tests.

19.3.1.2   Typical Minimum Resistance Values

AC Motors, 75°C   120-volt - 1.12 megaohms
                              208-volt - 1.20 megaohms
                              240-volt - 1.25 megaohms
                              480-volt - 1.50 megaohms

DC Motors, 75°C   All voltages - 1.00 megaohms

High-Voltage Circuit Breakers, 20°C   10,000 megaohms

High-Voltage Bushings, 20°C   10,000 megaohms

Insulated Cable - Varies as a function of type and thickness of insulation; see ICEA Standards

Transformers, Oil-Filled, 20°C $\dfrac{1.5E}{kVA}$
  Where:
      E   = Voltage rating of winding under test
      kVA = Rated capacity of the winding under test

Transformers, Dry type, 20°C, where E and kVA are as defined above $\dfrac{30E}{kVA}$

Other Equipment - Refer to Manufacturer's Data

19.3.2   Power Factor Test

This test is used to measure the power factor of the insulation in all types of electrical equipment and cable. The test has to be conducted at temperatures above 0°C since ice is a relatively good conductor. This test provides an indication of the quality of the insulation. Values obtained during the acceptance tests are compared with expected ranges of values determined from similar equipment. After the initial tests, comparison is made between values obtained at different times so as to establish a trend and thus anticipate potential troubles. Whenever possible, incorporate power factor tests into the routine factory tests for equipment. The acceptance test values may then be directly compared with the factory values.

19.3.2.1   Equipment Required: Test equipment, such as manufactured by the Doble Engineering Company or Biddle Company, Inc., Hipotronics, and others, is among that suitable for this purpose.

19.3.2.2   Acceptable Values: Acceptable values of power factors for various items of equipment are provided with the test equipment. Additionally, equipment manufacturers frequently provide this data for their specific equipment. The values given in Table 19-3 for a few common items are provided for reference only, so as to illustrate the very low magnitudes of power factors encountered.

19.3.3   DC High Potential Test

This is a test of the dielectric strength of insulation. It is used to determine the quality of the insulation in electrical equipment, particularly for items with solid dielectrics such as porcelain, rubber, PVC, PE, Micarta, etc. It is not generally used for on-site testing of equipment windings, with the exception of motor-generator windings, or on oil-filled equipment.

Table 19-3: Acceptable Power Factor Values

Item	% P.F. at 20°C
Bushings, Condenser and Oil Filled	0.5
Bushings, Compound Filled	2.5
Transformers, Oil Filled, New	0.5
Transformers, Oil Filled	1.0 – 2.0
Cable, PILC	0.3
Cable, Varnish Canibric Insulated	4.0 – 8.0
Cable, Rubber Insulated	4.0 – 8.0

Exercise extreme care when applying the test voltage so as to avoid equipment damage. Successful withstand of the voltage indicates satisfactory dielectric strength. In addition, a comparison of the charging current between tests over a period of time will indicate the degree of deterioration of the insulation as well as an examination of the plot of the leakage current vs. time during the "soak" portion of the test.

Theoretically, the steady-state test current should be constant with time for any one value of applied voltage. This constancy with time is a good indication that the insulation under test can withstand the voltage being applied. Any tendency for this current to steadily increase with time at constant applied voltage is a warning that the insulation under test may be damaged by a continuation of the test at that voltage. A plot of total test current versus time should result in a curve as shown in Figure 19-1.
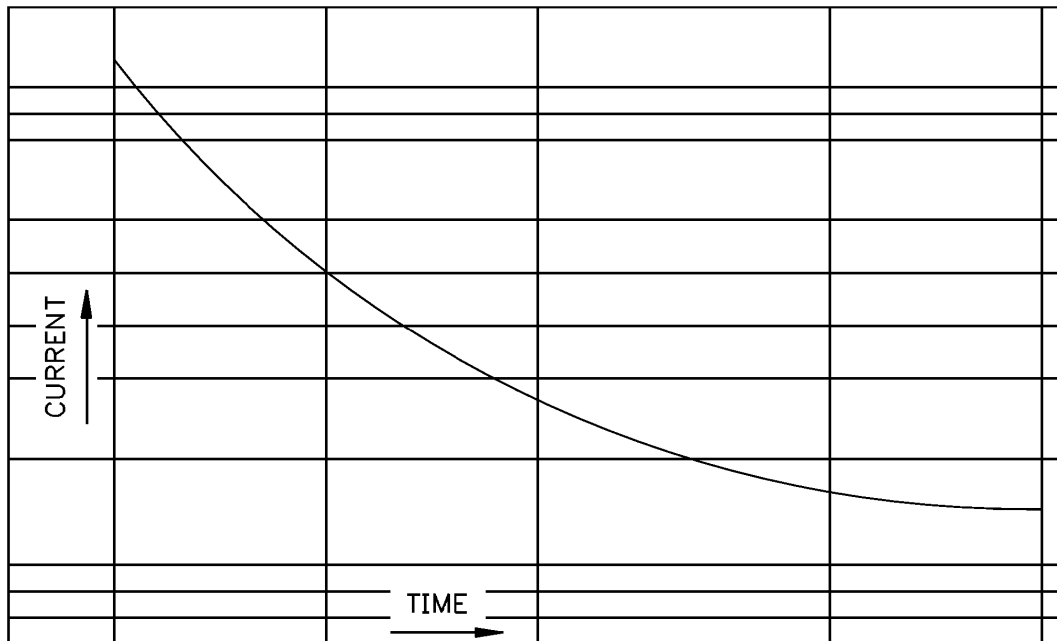

Figure 19-1: DC High Potential Test, Typical Test Current Versus Time

For an insulation test that is clean, dry, and free of voids, the test current at the lower voltage levels should not only be constant with time, but should increase lineally at each higher voltage according to Ohm's Law. A plot of steady-state test current versus voltage will result in a graph as shown in Figure 19-2.
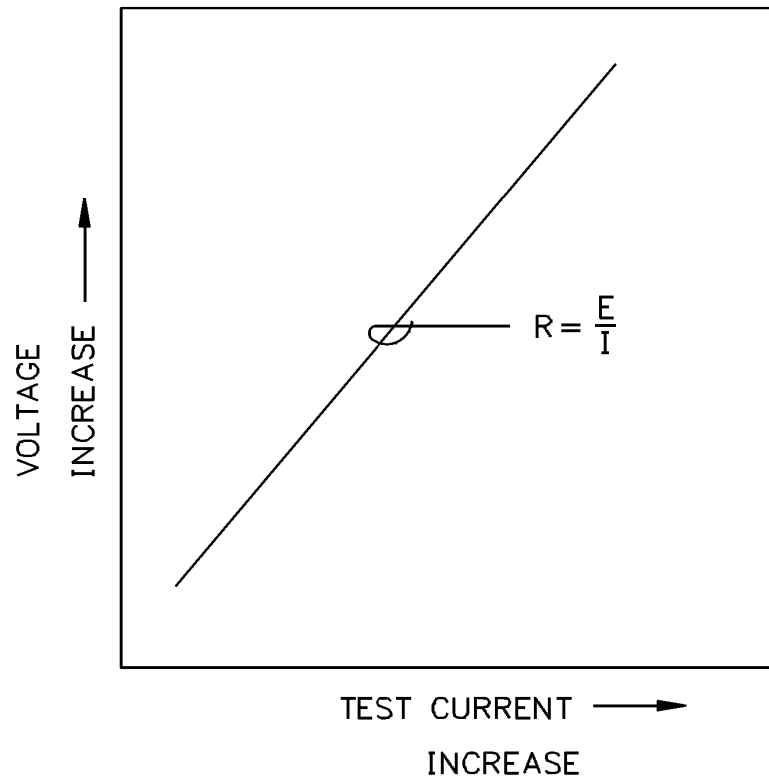
Figure 19-2: Steady Current Versus Voltage

19.3.3.1   Equipment Required: DC high potential set, similar to those manufactured by Associated Research, Inc., Biddle Company., Hipotronics Inc., Von Inc., and others (0 to l00 kV or higher, as required).

19.3.3.2   Typical Test Voltages

Acceptance Tests:	80 to 85% of factory test voltage
Periodic Tests:	60 to 65% of factory test voltage (55 to 60% of factory test voltage with PILC cable with neoprene jacket)

19.3.4   Dielectric Absorption Test

This test is again a test of the quality of the insulation. It is applicable to transformers, regulators, and other similar devices as well as shielded high-voltage power cable. It is not possible to provide a range of values for the results of this test. Its primary function is to provide an indication of deterioration prior to complete failure.

This test is performed by charging the insulation under test with an insulation resistance test set. The test is applied for a period sufficient to fully charge the cable. Resistance readings are taken every 15 seconds during the first 3 minutes and at 1-minute intervals thereafter. The test shall continue until three equal readings are obtained. This final reading shall be recorded. All windings or other conductors (in the case of a cable) not being tested have to be grounded. The tank (or shields) has to be grounded also.

19.3.4.1   Equipment Required: 2500-volt motor-driven megger or multi-range megger with voltage regulator.

19.3.4.2 Typical Readings

Table 19-4: Typical Insulation Resistance Values

Condition	60:30 Sec. Ratio	10:1 Min. Ratio
Dangerous	—	Less than 1
Poor	Less than 1.1	Less than 1.5
Questionable	1.1 to 1.25	1.5 to 2.0
Fair	1.25 to 1.4	2.0 to 3.0
Good	1.4 to 1.6	3.0 to 4.0
Excellent	Above 1.6	Above 4.0

19.3.5 AC Over-Potential Test

This test is performed to verify the integrity of the insulation in low-voltage devices (600-volt and below) and associated wiring. Observe specific manufacturers' recommendations before applying this test to solid-state components. The test consists of applying an ac voltage to the device for 1 minute and verifying the successful withstand of this voltage.

19.3.5.1 Equipment Required: AC high potential set, similar to those manufactured by Biddle Company or Hypotronics Inc. (0 to -2500V output or higher as required).

19.3.5.2 Test Voltages

Acceptance Tests: Twice the operating voltage plus 100 volts, but no less than 1500 volts
Periodic Tests: 1.7 times the operating voltage

19.3.6 Contact Resistance Test

This test is used to measure the resistance of the main contacts of a circuit breaker. A rise in resistance is an indication of the need for maintenance or replacement of the contacts.

19.3.6.1 Equipment Required: A digital low-resistance ohmmeter as manufactured by the Biddle Company, or similar.

19.3.6.2 Typical Readings: Refer to data provided by manufacturer with respect to the maximum permissible resistance. Typical ranges, however, are as follows:

Circuit breakers: 10 to 50 micro-ohms (medium voltage)
                                     50 to 350 micro-ohms (high voltage)

Reclosers: 50 to 200 micro-ohms

19.3.7 Winding Resistance Test

The winding resistance in a motor, transformer, regulator, etc., is not subject to change unless turns are open or short-circuited. An accurate measurement of the resistance at time of acceptance will thus permit future assessment of winding faults. Periodic checks will disclose shorted turns before further problems occur. Results have to be corrected for temperature.

19.3.7.1   Equipment Required: Kelvin Bridge suitable for measuring less than 1 ohm.

19.3.8   Insulating Oil Tests

Perform neutralization number, interfacial tension, dielectric strength, color, and visual examination tests as described in IEEE Std. C57.106, "Guide for Acceptance and Maintenance of Insulating Oil in Equipment." A comparison of the values obtained for each test over a period of time will indicate the gradual deterioration of the oil unless oil treatment has been performed. Sudden or accelerated changes in the dielectric strength are not normally encountered. Should a large change occur, perform complete inspection of the transformer rather than just instituting a treatment program.

A power factor test of the oil is a somewhat less accurate method of evaluating the dielectric strength of the oil than the ASTM standard method. It is a suitable substitute if suitable facilities for the ASTM test are not available.

It should be used, however, for periodic routine tests only. Tests conducted in association with trouble finding should be by the ASTM method.

19.3.8.1   Equipment Required: Two options exist with respect to the performance of insulating oil tests. The option adopted is generally a function of the size of the system, i.e., whether the need for such tests is great enough to warrant the procurement of all equipment required. The two possibilities are:

1.   Submit an oil sample to a qualified laboratory for determination of the neutralization number, interfacial tension, dielectric strength, gas analysis, and color test.

2.   Perform tests on site where possible, using the following equipment and methods:

   a.   Neutralization number. Calculate value by color-indicator titration method, ASTM Std. D974.
   b.   Interfacial tension. Measure using a surface tension tester such as is manufactured by Technical Associates or Fisher Scientific Co., ASTM Std. D971, ASTM Std. D2285.
   c.   Color test. Perform test in accordance with ASTM Std. D1500, which includes a field test procedure. Submitting a sample to a testing laboratory is preferred.
   d.   Dielectric strength. Measure using a tester such as the megger or Hypotronics Oil tester, ASTM Std. D877 or ASTM Std. D1816, as designated by the manufacturer.

19.3.8.2   Results: When the results of the insulating oil tests reach the following values, consider performing the operation indicated:

- Neutralization number. When the number exceeds 0.35 to 0.5 for transformers or for circuit breakers, reclaim the oil should. See IEEE Std. C57.106.

- Interfacial tension. When tension is less than 18-dynes/cm, reclaim the oil. See IEEE Std. C57.106.

- Dielectric strength. When the dielectric strength is less than 28 kV with a standard gap, recondition the oil by filtering.

- Color test. When color exceeds 3.5, reclaim the oil. See IEEE Std. C57.106.

- Visual examination. If the oil is cloudy, dirty, or contains visible water, reclaim the oil. See IEEE Std. C57.106.

For interpretation of test results gas in transformer oil, see IEEE Std. C57.104, "IEEE Guide for Interpretation of Gases Generated in Oil-Immersed Transformers."

19.3.9   Combustible Gas Analysis

A combustible gas analysis is performed to determine the amount, if any, of various types of combustible gases in the transformer gas cushion. These combustible gases are produced over time by small-magnitude turn-to-turn or other internal arcing faults. Internal arcing involving the core or other steel parts may also result in particles of carbon in suspension. Upon detection of combustibles, repeat testing at shorter intervals so as to ensure removal of the unit from service before major trouble occurs.

19.3.9.1   Equipment Required: It is generally desirable that a sample be submitted to a laboratory for a complete analysis. This analysis will provide details of the specific gases present.

Results indicating 0.5 to 5.0 percent, by volume, of combustible gases indicate the probable existence of an incipient fault. This necessitates close observance of the unit and the need for additional tests at shorter intervals. With percentages higher than 5 percent, it is recommended that the unit be taken out of service for detailed internal inspection. It is possible to examine the insulating oil itself for dissolved gases and carbon in suspension. This should be accomplished in a laboratory. Similarly, the gas collected in a "Buchholtz" relay should be analyzed in a laboratory.

19.3.10   SF$_6$ Gas Analyses

SF$_6$ gas used in circuit breakers is subject to contamination as a result of the products released during the interruption of current. This contamination increases with the severity of the fault and with the deterioration of the breaker contacts. Specific tests are not normally performed since the gas should be reconditioned on a regular basis in accordance with the manufacturer's recommendations.

Refer to specific equipment instruction books for additional requirements, if any.

19.3.11   Timing Test

A timing test is performed at the time of acceptance and again after all adjustments or replacements of contacts in the circuit breakers. The test is used to verify that all poles of the circuit breaker and all series contacts in each pole are operating simultaneously. Time the circuit breakers as close as possible to the tolerances provided by the manufacturer.

19.3.11.1   Equipment Required: Depending on the type of circuit breaker being tested, use one of the following test devices:

a.   A circuit breaker operation analyzer such as one manufactured by the Cincinnati Clock and Instrument Co. for breakers having a common operating shaft between poles such as is the case with oil circuit breakers.

b.   A multi-channel oscillograph for air blast and most SF$_6$ circuit breakers. This oscillograph has to have sufficient channels so as to provide one channel for every main contact and every

resistor contact, and also for event marking such as time of energization of the operating circuit. In all, probably a 24-channel unit is required. The unit should have a frequency response of l50 to 5000 cycles per second.

19.3.12 Motion Analyzer Test

The motion analyzer test is conducted to verify the good condition and proper adjustment of the mechanical operating linkages of a circuit breaker. A graphical representation of the elapsed time versus distance traveled is plotted. Any wear or poor adjustment will result in a non-uniform curve. Conduct this test in conjunction with the timing test.

19.3.12.1   Equipment Required: Circuit breaker operation analyzer as manufactured by the Cincinnati Clock and Instrument Company, M & G Instrument Company, or Barnes Engineering Company.

19.3.13 Series Overcurrent Test

Test all reclosers and low-voltage power circuit breakers having series trip devices periodically to verify the calibration and proper operation of the device. Perform the test at a number of current levels so as to verify the current versus time operating characteristics and the minimum instantaneous trip current level, if applicable.

19.3.13.1   Equipment Required: Test equipment similar to that manufactured by Multi Amp Corporation, General Electric Company, EIL Laboratories, etc., is required to provide a single-phase calibrated current source.

19.3.14 Turns Ratio Test

Periodically perform a turns ratio test as an aid in detecting turn-to-turn short circuits in power and instrument transformers. When evaluating the initial test results, give proper consideration to manufacturing tolerances.

19.3.14.1   Equipment Required: A turn ratio test set as manufactured by the Biddle Company is a convenient device. The test methods outlined in ANSI standards require less specialized equipment.

19.3.15 Polarity Test

Perform polarity tests on all power and instrument transformers after installation and again after any removal and replacement of a unit.

19.3.15.1   Equipment Required: Same as indicated for the turns ratio test or a battery and a d'Arsonval Meter.

19.3.16 Protective Relay System Tests

Subject all protective relays and each protective relaying scheme as a whole to operational tests at least once per year. The test will vary depending on the particular scheme and component relays; however, the test should in all cases be of the type where actual abnormal operating conditions are simulated and the proper operation of all components is checked.

Use multi-phase current and potential sources where applicable, rather than attempting to test multi-phase devices with single-phase sources.

Whenever possible, use an oscillograph or other type of multi-input events recorder for timing of the various components.

Refer to particular instruction books for specific test values, settings, and other pertinent data.

19.3.16.1   Equipment Required

    a.   Test set, as manufactured by AVO International or equal
    b.   Phase shifter, as manufactured by AVO International or equal
    c.   Auxiliary current and instrument transformers
    d.   Portable meters

19.3.17 Meter Calibration Tests

Test indicating instruments by comparison with a portable instrument that is connected into the same circuit as the instrument being tested. Test switches are usually provided for this purpose on the front of the panel.

Energy meter testing is usually performed in the cooperative's meter shop and thus is not provided for at the substation site.

19.3.17.1   Equipment Required: Many test methods are employed, each of which requires different equipment. Typically, one of the following methods is used:

    a.   Portable standard loads
    b.   Portable rotating standard
    c.   Single-phase series tests
    d.   Element balance tests
    e.   When calibrating meters, the following loads should be used:
           10% load at 1.0 pf.
           100% load at 0.5 pf.
           100% load at 1.0 pf.

19.3.18 Capacitance Test

Verify the capacitance coupling capacitors, the condenser section of bushings, and other similar capacitive devices at time of installation. Periodic measurements are usually not made unless a specific reason is incurred.

19.3.18.1   Equipment Required: Schering Bridge or equivalent.

19.3.19   Pressure Test

All high-pressure receivers and associated piping should be subjected to a pressure test at the time of installation and any time thereafter when the system has been subjected to repairs, extensions, alterations, etc. The pressure utilized for this test should be approximately 150 percent of normal pressure in systems

that operate below 100 psi. In higher pressure systems, the normal operating pressure is usually sufficient. In either case, seal the system and monitor the pressure over at least 8 hours (overnight is preferable). The only pressure variations should be those caused by a change in temperature.

19.3.19.1   Equipment Required: The pressure gauge required is normally an integral part of the system being tested.

19.3.20 Ground Grid Resistance Measurement

As noted in Chapter 18, Inspections, the ground grid resistance should be measured periodically to verify that significant changes have not occurred as a result of changes in groundwater levels or other similar natural phenomena. The value obtained should be compared with previously measured values or with design criteria values in the case of a new installation.

19.3.20.1   Equipment Required: Three-probe measuring device similar to Vibroground equipment as manufactured by Associated Research, Inc. or Biddle Company.

19.4   REFERENCES

ASTM Std. D877, "Test Method for Dielectric Breakdown Voltage of Insulating Liquids Using Disk Electrodes."

ASTM Std. D971, "Test Method for Interfacial Tension of Oil Against Water by the Ring Method."

ASTM Std. D974, "Test Method for Acid and Base Number by Color-Indicator Titration."

ASTM Std. D1500, "Test Method for ASTM Color of Petroleum Products (ASTM Color Scale)."

ASTM Std. D1816, "Test Method for Dielectric Breakdown Voltage of Insulating Oils of Petroleum Origin Using VDE Electrodes."

ASTM Std. D2285, "Test Method for Interfacial Tension of Electrical Insulating Oils of Petroleum Origin Against Water by the Drop-Weight Method."

IEEE Std. C57.104, "Guide for Interpretation of Gases Generated in Oil-Immersed Transformers."

IEEE Std. C57.106, "Guide for Acceptance and Maintenance of Insulating Oil in Equipment."

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CHAPTER 20
MAINTENANCE

An effective and efficient maintenance program for substation equipment includes scheduled periodic maintenance as well as corrective procedures that address specific equipment-related problems.

20.1   GENERAL

Periodic or time interval-based maintenance procedures, more commonly referred to as preventive maintenance, are developed and instituted in an attempt to minimize unscheduled service interruptions. The degree of success of such procedures is generally reflected by the cooperative's ability to balance system reliability with accepted levels of risk of failure or system outage.

Periodic maintenance procedures are generally performed in conjunction with normally scheduled inspection and testing programs, which are outlined in Chapters 18, Inspection, and 19, Tests.

Specific details for the performance of periodic maintenance vary considerably depending on the make, model, age, load profile, etc. of the specific equipment. In addition, a maintenance program developed for substation equipment should consider site environmental conditions, site location and access, and priority of the substation equipment to overall system reliability.

Refer to manufacturers' instruction books for all equipment requirements.

20.1.1   Records

Maintain a record of inspection and test results that indicate the condition of equipment and the maintenance history, as outlined in Chapter 18, Inspection, in an electronic database. In addition to the details contained therein, include at least the following information in these records:

1. A description or outline of the basis for the specific maintenance program
2. The date when maintenance was performed and the latest date when it should again be performed
3. The condition of the equipment after the inspection or maintenance
4. Any requirements for special follow-up work

20.1.2   Safety

Certain maintenance procedures may be performed with the equipment in service while other procedures require that the equipment be de-energized. Scheduled outages closely coordinated with power plant or transmission line maintenance quite frequently afford the best opportunity for maintenance. When it is necessary to remove a piece of equipment from service without de-energizing the total substation, maintain minimum safety clearances as specified in Chapter 18. Install temporary barriers to isolate the equipment being worked on from adjacent energized equipment.

20.2   PERIODIC MAINTENANCE

Periodic maintenance programs should consider original equipment manufacturers' (OEM) recommendations with respect to details of the maintenance performed and to its frequency. OEM

recommendations for maintenance are typically conservative. Cooperatives should look for ways to perform equipment maintenance based on actual conditions. A study of all industries shows that overly conservative maintenance based on OEM recommendations can lead to more failures of equipment that might otherwise be functional. Common maintenance procedures and their frequencies are indicated in Table 20-l.

Table 20-1: Recommendations for Periodic Maintenance

Equipment	Clean Exposed Porcelain	Clean, Lubricate & Adjust Mech.	Clean or Replace and Align Contacts	Tighten Connections	Major Overhaul	Clean & Burnish Contacts	Lubricate Aux. Motors	Replace Dehydrator in Breather	Change Oil in Gear Boxes	Check Liquid Levels
Transformers, Inert Gas Cushioned	12			12			6			
Regulators	12			12						
Oil Circuit Breakers	12	12		12	*					
Air Circuit Breakers	12	12		12	*					
Vacuum Circuit Breakers	12	12		12	*					
SF$_6$ Circuit Breakers	12	12		12	*					
Air Blast Circuit Breakers	12	12		12	*					
PTs	12			12						
CTs	12			12						
CCPDs	12			12						
Surge Arresters	12			12						
Disconnects and Air Break Switches	12	12	12	12			6		24	
Vacuum Switches	12		12	12						
Circuit Switches	12		12	12						
Capacitors	12			12						
Metal-Clad Switchgear		12		12						
Relays				12		12				
Transformer Tap Changer Mech.					*					
Transformer, Conservator Type	12			12					6	
Station Battery										2

Number indicates recommended interval of time (in calendar months) between maintenance times. Asterisk (*) indicates that the requirement for maintenance is a function of the number and/or type of operations.

20.2.1 **Specific Requirements**

In addition to those items of maintenance listed in Table 20-l, the following maintenance tasks should be performed at the time regular visual inspections are made:

1. Eliminate any low spots that have developed in the substation yard.
2. Remove trash from the area.
3. Replace all burned-out lamps.
4. Remove bird nests and other items from the vicinity of energized parts.
5. Clean and refinish defects in paint and galvanizing.
6. Periodically remove vegetation. If chemical application for removal of vegetation is required, consult the local farm extension agency or governing authority for proper methods and chemicals.

Exercise extreme caution if maintenance is performed near energized equipment.

20.2.2 Painting

Periodically, depending on the geographic location, local environment, etc., equipment, fences, and structures have to be repainted. The following should be considered as minimum requirements:

20.2.2.1 Equipment and Other Painted Items

a. Thoroughly remove all loose paint, blisters, and scale. Where the condition of the finish is poor remove the paint entirely. Wire brushing, sand papering, or scraping is desirable where only partial surface cleaning is necessary. Paint removers will soften and aid in removal. However, neutralize the paint remover before attempting to paint. For removal of oil and dirt, use weak solvents such as mineral spirits, other petroleum thinners, or turpentine substitutes.

b. Paint as soon as possible after cleaning. Cover all bare metal with a primer. Where only chalking has occurred, one finish coat is sufficient. Primer and finish paints may be obtained from most equipment manufacturers and sometimes from local sources. A zinc chromate alkyd resin primer followed by an alkyd base paint is a suitable air-dry combination for exterior surfaces. Allow the primer coat to air-dry thoroughly and follow it with two finish coats with sufficient time allowed between coats for drying.

20.2.2.2 Galvanized Structures and Fences

The protective coating produced by the galvanizing process is normally a long-lived coating; however, the coating will eventually fail and rust will appear. It has been observed that Class II hot-dipped galvanizing on chain link fences in rural locations will normally furnish adequate protection for many years. The life of the coating on structural steel used in substations should generally be longer than 12 years, except possibly for upper flat surfaces of horizontal members. Any failure of the coating will usually occur in spots rather than over an entire surface. The following procedure is recommended:

a. Clean the surface with a wire brush or by other mechanical means to remove rust and dirt. If the surface is contaminated with grease or oil, use a solvent to remove those contaminants. Mineral spirits or a weak solution of trisodium phosphate can be used as the solvent. A solution of 1 ounce of trisodium phosphate to 1 gallon of warm water is suggested for cleaning the metal. In the event that it is uneconomical or impractical to remove all rust, a reasonably satisfactory job can be obtained by deactivating the rust through chemical treatment. A weak solution of phosphoric acid is suggested for deactivating rust. Use proper skin and eye protection.

b. Apply a priming coat to the clear dry surface using a good zinc dust–zinc oxide paint. Allow ample time for the paint to dry before applying the finish coats.

c. Apply two finish coats using the same type of paint as was used for priming. Allow ample drying time between finish coats. One finish coat is needed for areas on which the galvanized coating remains intact. The color of the paint is gray, but colors in oil may be added to the finish coats to obtain other shades. Other paints normally used as final coats for metal (such as aluminum paint) may be used as the final coat in place of the zinc dust–zinc oxide paint.

It is recommended that painting of outdoor metal work be done only when the temperature is above 7.2°C (45°F) and when the relative humidity is below 80 percent.

The durability of paint coating depends on thickness, cohesion, and continuity. Generally 5 mils (0.005 inch) is an adequate thickness. The thickness should be uniform, and paint should not be easily scraped off the metal. Pay particular attention to welds, edges, and other hard-to-coat areas.

20.3   UNSCHEDULED MAINTENANCE

Any abnormal conditions that are noted during any inspection of the substation yard or equipment may need to be corrected as soon as possible, depending on the severity of the condition. In some cases, the equipment has to be removed from service prior to beginning maintenance. Some abnormal conditions and possible corrective measures may include the following:

1. **Loose or Corroded Connections.** Tighten or replace, depending on condition.
2. **Contaminated Bushings.** Clean all exposed surfaces, including casing, porcelain, and oil gauges.
3. **Leaking or Damaged Bushings.** Repair or replace.
4. **Deteriorated Insulating Oil.** Recondition or reclaim depending on situation (see IEEE Std. C57.106 and Chapter 19 of this bulletin).
5. **Low Pressure of Inert Gas Cushion.** Replace gas cylinder if required and check gas system for leaks, etc.
6. **Pressure Relief Device Operated.** Reset device and determine cause for operation.
7. **Oil Leaks.** Repair, tighten, weld, etc., as required.
8. **Sludge or Carbon Deposits in Tank.** Remove deposits and clean. Determine cause for deposit, i.e., deteriorated oil, internal faults, etc.
9. **Damaged Items.** In addition to the items contained in the previous paragraphs, it can be anticipated that certain abnormal items will be noted that can only be remedied by replacement of the damaged item. These include:

   a. Damaged potheads, high-voltage cable, porcelain (bushings, surge arresters, insulators, etc.), and other items subject to high electric stress.

   b. Failing capacitors, as evidenced by insulating fluid leaks around bushings or bases, bulging tanks, blown fuses on individual units or groups of units, etc.

NOTE: It may be necessary to de-magnetize the core in current transformers if they have been subjected to very high magnitude currents that have resulted in saturating the core. Modern high-accuracy current transformers show relatively little change in accuracy as a result of magnetization. However, should a current transformer core become magnetized by surges as a result of opening the primary circuit under heavy load or any other means, it may be conveniently demagnetized by several methods.

One reliable method requires connection of a variable ac source to the secondary of the current transformer to be demagnitized after the power circuit has been de-energized. During the test, the primary of the current transformer is left open-circuited. The secondary winding current is slowly increased from 0 to 5 amperes, and then steadily reduced to 0 again before disconnecting the test source from the secondary winding.

It is important to note that, when demagnetizing high-impedance current transformers, it may require up to 450 volts or higher across the secondary terminals. Appropriate caution is required.

20.4   RELIABILITY-CENTERED MAINTENANCE

As equipment in substations deteriorates and degrades over time, the probability of service interruptions as a result of component failure is increasing at the very time that competitive pressures demand higher levels of power quality and reliability. Some utilities are working to proactively address these issues by implementing a condition-based, predictive substation maintenance program using the concepts of reliability-centered maintenance.

Reliability is defined as the probability that a system will perform a given function satisfactorily for a specified time under specified operating conditions.

The fundamental goals of reliability-centered maintenance are to preserve the function or operation of a system and to schedule all preventive maintenance tasks. The system function that has to be preserved in substations is the delivery of safe, reliable electric power to customers.

There are four fundamental principles of pure reliability-centered maintenance theory:

1. The primary objective of reliability-centered maintenance is to preserve system function.
2. A good reliability-centered maintenance program should identify specific failure modes to define loss of function or functional failure.
3. A reliability-centered maintenance program should prioritize the importance of the failure modes.
4. A reliability-centered maintenance program should identify effective and applicable preventive maintenance tasks.

20.4.1   <u>Methods</u>

A reliability-centered maintenance program may be used to identify the appropriate application of the four traditional methods of asset maintenance performed today. The four methods of equipment maintenance are corrective, preventive, proactive, and predictive.

Corrective maintenance is a reactive form of maintenance that uses a system failure as a signal to perform a repair task. For non-critical components or components that do not permit cost-effective maintenance, corrective maintenance is acceptable. However, a run-to-failure approach is not acceptable if the system function is lost or the cost of the maintenance task that would have prevented failure is reasonable relative to the cost of the outage.

Preventive maintenance is a time interval- or usage rate-based maintenance method. Anthony Smith, author of *Reliability Centered Maintenance*, has identified ten common maintenance problems encountered in traditional preventive maintenance programs for industry in general that support the need for a better method of performing preventive maintenance:

1. Insufficient proactive maintenance because most effort is in corrective maintenance (i.e., responding or reacting to problems)
2. Frequent problem repetition because there is only time to restore a system to operation and no time or effort spent to determine the cause and repair the root of the problem
3. Erroneous maintenance work that leads to a plant outage
4. Proven maintenance practices that are not communicated, taught, or implemented
5. Unnecessary and conservative preventive maintenance that does not contribute to overall plant reliability and contributes to human error

6. Unclear rationale for preventive maintenance with undocumented procedures that have no logical background or theoretical basis
7. Maintenance programs that lack good record keeping or a method to track the decision making process
8. Use and acceptance of OEM recommendations for maintenance practices that do not apply to specific site conditions and that may be conservative so as to protect the OEM's warranties
9. Lack of standard practices among similar facilities
10. Lack of quality, practical, predictive maintenance tools and procedures

Two key questions have to be answered in a traditional preventive maintenance program: (1) What tasks have to be performed? (2) When should they be performed?

Reliability-centered maintenance not only asks what preventive maintenance task should be performed and when it should be performed, but it answers "why" a preventive maintenance task is needed.

Reliability-centered maintenance uses a process known as age exploration to determine preventive maintenance intervals for components in which there is no determinable age–reliability relationship. If the regular preventive maintenance interval reveals no signs of degradation or incipient failure, the interval to the next preventive maintenance overhaul or inspection is increased by 10 percent. If again there are no signs of degradation or incipient failure, the process is repeated, adding 10 percent to the interval each time until the component requires attention or replacement. The maintenance interval is then reduced by 10 percent and that interval becomes the final task interval.

Reliability-centered maintenance clearly defines and documents reasons for how and why each preventive maintenance task is selected.

Proactive maintenance is the upgrade or redesign of components that consistently fail under normal design loading criteria or that violate safety codes, regulations, or guidelines. Proactive maintenance tasks typically result from the need to perform corrective maintenance because of system functional failure.

Predictive maintenance is based on the operating condition of a component. No component should have preventive maintenance performed on it unless its actual condition warrants the task. Predictive maintenance gives a snapshot in time of the actual operating condition of a component without interrupting the function of the component. A predictive maintenance approach allows the preventive maintenance task to be scheduled and reduces overall operations and maintenance costs by dramatically reducing corrective maintenance tasks.

Of the four traditional methods of maintenance, the predictive maintenance approach seems to be the most sensible. The ability to predict system failure and act precludes corrective maintenance. Knowing the actual operating condition of equipment provides the user the reason why any preventive maintenance should be performed. Proactive maintenance can be considered as more of a function of engineering analysis due to a consistent failure of a part or component. As a result, there is a growing number of predictive maintenance approaches for substation equipment on the market today.

20.4.2 Application

The best approaches adapt reliability-centered maintenance theory in a practical, understandable manner to 1) prioritize assets, 2) assess the condition of the equipment based on known failure modes, and 3) identify and schedule effective preventive maintenance.

The application of reliability-centered maintenance to substations requires a careful and detailed prioritization of where the next maintenance dollars will be spent in order to improve system reliability of those prioritized assets that have the greatest impact on system function. The diverse attributes that contribute to this process include:

- Substation voltage
- Equipment age
- The number of sensitive customers directly or indirectly served by the circuits out of the substation
- The total number of breaker operations to date
- The total number of extended outages to date

Maintenance logs and system operations logs will provide this operational information. Each parameter is weighed according to relative importance as determined by engineering judgment, with a heavy emphasis placed on customers served and outage history. The parameters and weightings can be entered into a spreadsheet to calculate system priorities. Each parameter will be multiplied by its assigned weighting, and all the parameters for each substation will be summed to provide an overall score.

A sensitivity analysis can be made to vary the weightings as needed. The spreadsheet can then sort the substations in ascending order, providing the user with the first substations that deserve a detailed predictive assessment.

Assessing the condition of the parts and components of a high-priority substation starts with a detailed assessment of existing maintenance activities. Interview key personnel from top to bottom of the maintenance organization to discover what maintenance practices are perceived to occur and what practices actually occur. This discovery process helps to define the culture of a maintenance organization and identifies the current approach to substation maintenance. In addition, conduct a thorough review of maintenance records to identify and document specific problem equipment and recent corrective maintenance activity at the selected substation. The assessment may reveal the lack of information or the need to better manage the information.

The next step in the assessment of the parts and components of a high-priority substation is the performance of a Detailed Inspection Procedure and Online Equipment Evaluation.

The Detailed Inspection Procedure guides an experienced field inspector through the step-by-step inspection of major substation equipment by identifying specific failure modes for equipment that can be verified by visual observation or examination of the maintenance records. Inspect each major electrical and structural component of a substation: transformers, breakers, arrestors, circuit switches, disconnect switches, capacitor banks, batteries, relays, switchgear, insulators, terminations, buswork, current and potential devices, grounding, support structures, concrete foundations and control trench, control building, and site civil conditions.

The Detailed Inspection Procedure prompts the inspector to provide a percentage condition adjustment factor based on a recommended condition range for each major substation component. The percentage condition adjustment rewards or penalizes components based on visible failure modes that can impact the function of the component or the entire substation. The percentage condition adjustment is an attempt to prioritize preventive maintenance tasks and provide guidance for subsequent inspections on the visible, external aspects of a substation and is not an attempt to quantify the projected functional life of a component. For additional information on inspection, see Chapter 18, Inspection.

Once the Detailed Inspection Procedure and Online Equipment Evaluation are complete, it is important to report on prioritized action items for scheduled preventive maintenance. The substation components with the greatest negative percentage condition adjustment (e.g., component function is heavily impacted by visible incipient failure modes) receive the highest priority for scheduled preventive maintenance.

In addition, occurrence reports based on the results of the Online Equipment Evaluation prioritize the need for scheduled preventive maintenance on the internal components of substation equipment. High inaudible noise levels, unusual temperature differentials, slow breaker operations, or contaminated oil samples provide good reasons why preventive maintenance should be scheduled. Lack of any unusual characteristics in the Online Equipment Evaluation may indicate that there is no reason to perform routine preventive maintenance because of the actual operating condition of the equipment.

Repeat this Detailed Inspection Procedure and the Online Equipment Evaluation process for the second highest priority substation. Set regular inspection intervals using age exploration.

As the concepts of reliability-centered maintenance are implemented for each substation on the system, the user can expect to know why preventive maintenance tasks are performed and can expect to achieve the following results:

1. Better system availability and reliability
2. Increased worker safety
3. Extended equipment life
4. Improved long-range planning for asset management
5. More cost-effective preventive maintenance as a result of scheduling men and equipment
6. Reduced O&M expenses due to reduced corrective maintenance costs

The results of a Detailed Inspection Procedure and Online Equipment Evaluation identify the highest priority "accidents waiting to happen" so that corrective measures can be immediately scheduled to maintain system function. As a result, the cost of corrective maintenance in the form of scheduled preventive maintenance may initially increase substation maintenance budgets. However, over time, the application of reliability-centered maintenance improves system reliability and reduces O&M expenses.

20.4.3 Conclusion

The fundamental goal of reliability-centered maintenance is to preserve the function or operation of a system. Specifically, the function that has to be preserved for electric substations is the delivery of safe, reliable electric power to customers. The concepts of reliability-centered maintenance that have been used so effectively in other industries can be applied to electric substations in a viable and effective maintenance approach that proactively addresses the challenges of improving system reliability and controlling costs in an increasingly competitive energy delivery market.

20.5 REFERENCES

IEEE Std. C57.106, "Guide for Acceptance and Maintenance of Insulating Oil in Equipment."

IEEE Std. P1266, "Trial-Use Guide for Evaluation and Development of Substation Life Extension Programs."

Smith, Anthony M., *Reliability Centered Maintenance*, New York: McGraw-Hill, 1993. ISBN 0-07-059046-X.

CHAPTER 21
UPRATING AND EXPANDING EXISTING SUBSTATIONS

21.1 APPLICABILITY

All substation design and construction including uprating and expanding has to be based on sound practices to ensure safe, reliable operation. While it may not always be practical in uprating to attain every desired recommended clearance and spacing, minimums where established in this bulletin or other applicable national or local standards have to be met or exceeded.

Modern practice requires that certain environmental and safety issues be addressed in any substation uprating or expansion project, even though the existing substation may not have been designed with such issues in mind. Seismic criteria for the area of installation have to be considered. A suitable oil spill prevention plan, possibly including oil containment facilities, has to be implemented. Fire protection methods (including physical separation, barrier walls, and sprinkler systems) should be weighed against the safety concerns and the costs of fire insurance to arrive at an appropriate design. Several other environmental issues should be considered, as applicable: noise abatement, aesthetics, disposal and containment of hazardous materials, and containment of electromagnetic fields.

21.2 FEASIBILITY

Cost is usually a primary factor when determining a course of action: construction of a new facility versus uprating and/or expanding an existing facility. Prepare construction cost estimates for the schemes under consideration. Generally choose the plan with the most favorable cost/benefit ratio, provided that such action is consistent with the near- and long-range system plan.

With facility expansion or new construction, include in cost estimates potential impacts due to underground obstructions and environmental concerns.

Consider substation uprating as an alternative where increased capacity is required and routine expansion is hindered due to lack of land area. During the initial planning of an uprating program, it may become apparent, after discussions with manufacturers, that such a program is not cost-effective. In this case, expansion or new construction is usually the most desirable course of action.

21.3 SUBSTATION UPRATING

In uprating substation equipment, the cooperation of the equipment manufacturer is usually required. Although an agent or distributor for the equipment vendor may initially be contacted, obtain final determinations from the manufacturer's headquarters engineering staff as to technical feasibility of the uprating, the cost of such work, and where the work can be done—field or manufacturing plant. It may be necessary for the work to be performed at the manufacturer's facilities or by its field service personnel to obtain proper warranty of the uprated equipment.

When equipment uprating is being considered, only the capacity is increased. The voltage level remains the same. Normally the location of incoming or outgoing circuits remains the same although they may be reconductored for increased capacity.

21.3.1   Major Equipment Uprating

21.3.1.1   Power Transformer: In the initial phase of a planned substation uprating, furnish the power transformer manufacturer with complete nameplate data. Additionally, supply original purchase information, such as purchase order number and date. This information will make it possible for the manufacturer to retrieve the original design calculations to determine the possible additional capacity.

If the original design was conservative, some additional capacity may be possible. A loading history may be necessary to confirm this. If the unit is oil insulated, self-cooled, the addition of radiators and fans should provide added capacity. If the unit is fan-cooled, additional or larger fans or radiators may add to available capacity. Insulating oil pumping, or additional pumping, may be necessary to further increase the rating. In some cases, internal leads may require inspection, testing, and even replacement.

There are variations between manufacturers but, in general, a 15 to 20 percent increase in MVA capacity may be possible.

21.3.1.2   Oil Circuit Breaker: Increasing the MVA capacity of a substation may necessitate increased circuit breaker ratings. Breakers may be inadequately rated for increased continuous and momentary currents and interrupting duty. Consequently, determine the fault and continuous current requirements of all associated breakers.

The existing oil circuit breakers may be adequate for the increased full load current but inadequate for the interrupting duty to be imposed.

Give the manufacturer of the breakers complete nameplate and purchase data together with the ultimate full load current and asymmetrical fault current expected from the uprating program.

From this data the feasibility of the program can be determined as far as the breakers are concerned.

New contacts and bushings may possibly overcome any full load current deficiency. Replacement of interrupter units could safely handle the increased interrupting duty.

Application of capacitors on a substation bus causes severe capacitive current switching duty. Compare rated capacitive switching current for the existing breakers with the anticipated duty to determine the need for breaker mechanism modifications. Consult the breaker manufacturer to determine the need for such modifications.

21.3.1.3   Current Transformer (CT): Current transformers should be evaluated for thermal rating under the uprate program by the equipment manufacturer when the apparatus is being assessed. If determined inadequate, replacement will be necessary. Next determine the ratio suitability. For example, a 3000/5 multi-ratio CT, being operated on the 1200/5 tap, can be reconnected for 2000/5 service.

Application of multi-ratio CTs on lower rated taps results in less accuracy and can lead to saturation of the CTs (with associated error) under heavy fault conditions. Consider these features in the CT evaluation when fault currents are increased.

21.3.1.4   Wave Trap: Since a wave trap or line trap is a current-rated device, it is undesirable to operate such equipment above the nameplate rating. In most cases of uprating, wave traps will require replacement.

21.3.1.5   Coupling Capacitor Voltage Transformer (CCVT): A CCVT is a voltage-rated device as is the associated line coupling tuner when the CCVT is equipped with carrier current accessories. Replacement will not be required for a capacity uprating program unless the addition of new metering or relaying exceeds the loading limits of the device.

21.3.1.6   Voltage Transformer (VT): A VT is in the same category as a CCVT relative to uprating.

21.3.1.7   Bus System: Two factors enter the uprating considerations regarding the substation bus system:

1.   Current-carrying capacity of the conductors and connections
2.   Fault current capability of the conductor support systems

An increase in bus current is directly proportional to the increase in substation MW capacity. However, the increase in bus heating is proportional to the current squared (I^2R). This heat increase has to be considered. Additional heat may, by conduction, affect connected apparatus. Also, it becomes progressively more difficult to maintain good bolted joints, free from deterioration, as the temperature increases. For these reasons, good practice generally indicates rating the bus for a 30°C (54°F) rise over a 40°C (104°F) ambient under full load conditions. Under emergency conditions consider a 25 percent maximum bus current increase. These loadings should, however, be limited to a couple of days' duration.

For heat rise computations, the necessary data and mathematical relations are available from conductor manufacturers and industry associations. An excellent publication of this nature, *Aluminum Electrical Conductor Handbook*, is available from The Aluminum Association, 750 Third Avenue, New York, NY 10017.

Once the thermal considerations of the uprated bus have been calculated, decide if the existing conductor should remain or be replaced. If strain bus, possibly only the drops need changing to a larger size. If the substation uprating is a measure to buy time prior to a more extensive program to serve load growth, possibly the bus need not be replaced.

The fault currents associated with a substation, in the case of rigid bus mounted with apparatus insulators on structures, cause stress in the insulators and structures. With the added capacity and consequent increase of the fault current, calculate these stresses be to determine if insulators or structures are adequate. Methods of calculation are described in Chapters 4 and 7.

The insulator cantilever strength will most likely be the weak element under the uprated condition. Several courses are open to remedy this situation. Insulators of increased cantilever strength can be installed on the center phase only. However, it may be necessary to change all insulators to higher strength, depending on the calculated forces. Additional bus structures to reduce bus span length may be an answer, although probably a costly solution. An alternative solution may be the addition of interphase, fiberglass insulators. Coordination with manufacturers is necessary to find a device that will work properly. Calculations are needed to verify that the additional weight that would be added to the bus is acceptable to the existing design.

21.3.1.8   Disconnecting Switches: The increased current of the uprated substation will require that the disconnecting switches be examined for full load rating. This can be done from the substation records or the switch nameplates. Also check the momentary current capability. If either the full load or momentary currents are found inadequate, consult the original equipment manufacturer. It may be

possible to uprate the switches by additions or replacement of the current-carrying parts and insulators. If this is not possible or the switch vendor no longer manufactures this product, replace the units.

21.3.1.9   Surge Arresters: Since the voltage level or substation BIL is not usually increased in the uprating program, the surge (lightning) arresters need not be changed. However, if the existing units are of old and outdated design, it is advisable to replace, in particular, those positioned for power transformer protection. Generally, silicon carbide arresters should be replaced with metal oxide arresters for the improved protection characteristics that are available.

21.3.1.10   Raceway System: Essentially, the only changes in the raceway system would be provisions for additional transformer fan and oil pump circuits. If the system is underground and spare raceways or ducts have not been provided, new direct burial plastic conduits can be installed above or beside existing duct banks, thus using the present routing.

21.3.1.11   Auxiliary Systems: In an uprating program the essential addition to the auxiliary systems will probably include new ac circuits for transformer fans and oil pumps. Consider these circuits as critical or essential loads and assign them a 100 percent demand factor. It is doubtful that the auxiliary system transformers, panelboards, and service conductors will need increasing in size. Normally these are specified conservatively. In addition, the operating history of the substation may indicate that the existing loads were assigned a demand factor in excess of the true factor. However, check the auxiliary system capacity nevertheless for adequacy. An additional panelboard may be required to provide for additional circuits. Consider fault current ratings of equipment downstream of an uprated auxiliary system transformer.

The most important equipment check to make of the ac system in an uprating program is the capacity of the automatic transfer switch. This switch may have to be replaced with a unit having a larger rating, both full load and momentary.

It is unlikely that the battery and charger system will be affected by a substation uprating, but also check these components to verify their adequacy.

21.3.1.12   Relaying and Metering: Unless the relaying scheme is being changed concurrently with the substation uprating program, the changes to existing relays will usually consist of revising the settings. Higher fault current ratings may result in the need for complete re-coordination of feeder and bus relaying. Some current transformers may have to be reconnected or replaced for different ratios both for relaying and metering. Since there is usually no voltage change in an uprating program, potential transformers and other voltage devices generally can remain the same.

21.4   SUBSTATION EXPANSION

21.4.1   General

Substation expansion is the addition of transmission, subtransmission, or distribution circuits to existing substations. These additional circuits may be required on the primary or secondary side. In some cases modifications to the switching scheme may be necessary or desirable. At the same time, capacity may be increased with the installation of an additional transformer(s). Figure 21-1 shows a substation expansion adding 69 kV line, a 69/12 kV transformer, and a 12 kV distribution structure to an existing substation consisting of 69 kV line, a 69/34.5 kV transformer, and a 34.5 kV distribution structure.

20' Gate

Enlarged to show detail below

Cø
Circuit Switcher
69kV Bø
Aø
Transformer
Bank #1

Cø
Bø 34.5kV
Aø

AC/DC
Load Center

Shielding
Pole

Cø
Future
Circuit Switcher
Future Light
69kV Bø
Aø
Future
Transformer
Bank #2

Cø
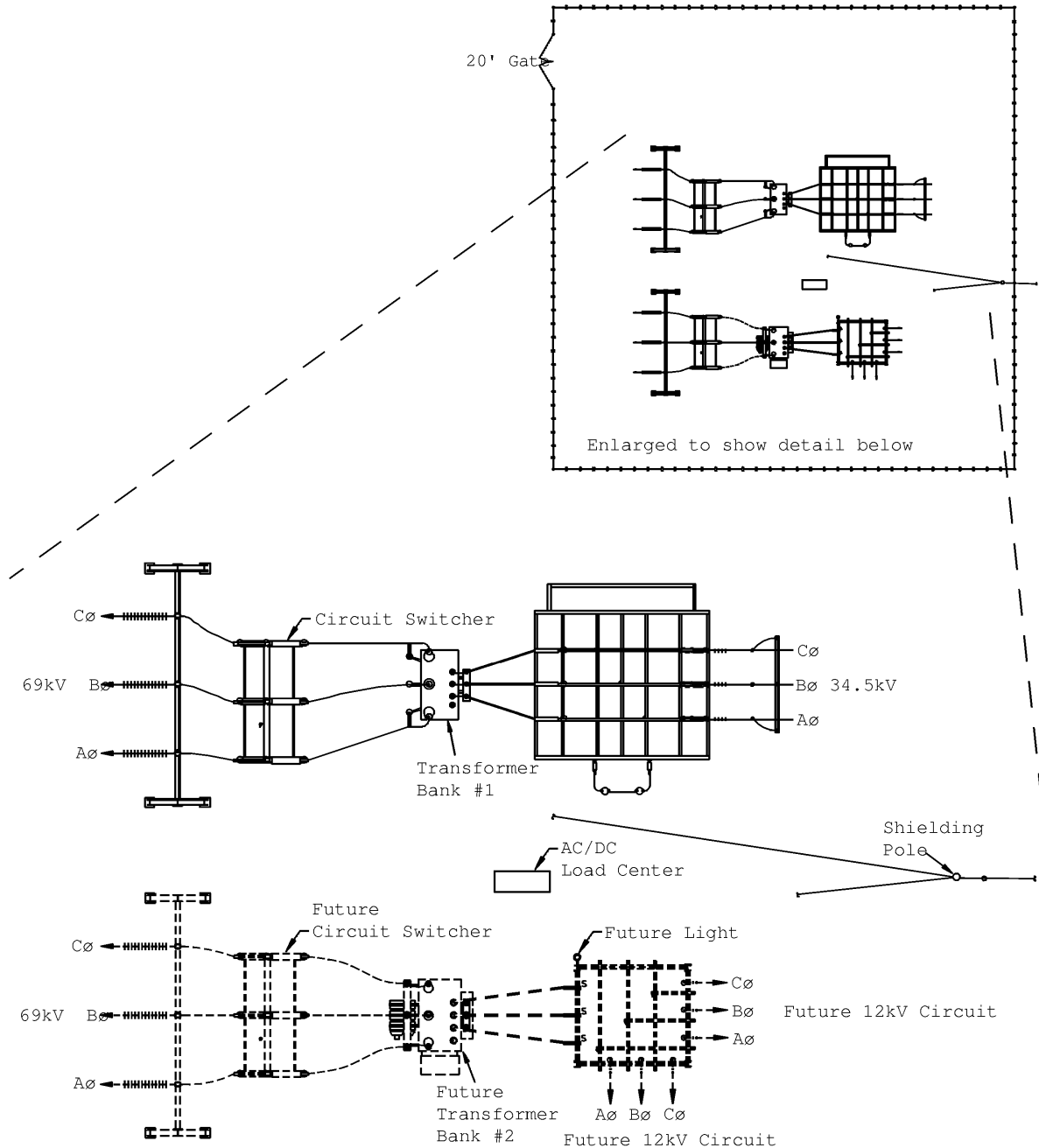Bø Future 12kV Circuit
Aø

Aø Bø Cø
Future 12kV Circuit

Figure 21-1: Substation Expansion

A planned expansion is also the time to consider the possibility of a different voltage level, for example, whether the expansion of a 115 kV substation be designed for future 230 kV. Phase-to-phase rigid bus spacing is nominally 2.13 meters (7 feet) and 3.35 meters (11 feet), respectively. Installing structures and buswork for a higher voltage spacing and clearance with operation at the present voltage may be warranted when the long-range system plan indicates increasing the voltage at a later date. When the expansion goes to the higher voltage, this portion could be coupled to the existing voltage through a suitable transformer or completely divorced from the lower voltage installation, depending on system configuration.

If a higher voltage construction is decided for the expansion and the higher voltage is contemplated within the near term (less than 10 years), design and install foundations for the higher voltage equipment. The advantages of the monolithic pour over the modification of a smaller foundation at a later date far outweigh the higher cost.

Reasonable equipment dimensions and weights for the higher voltage equipment are readily available from equipment manufacturers. The trend is to smaller, not larger, equipment so this risk is reasonable.

If future bus extensions are anticipated, it may be advantageous to install disconnect switches on the ends of the bus to facilitate the future construction with minimal outages. With the switches open, future bus extensions can be made on the dead side of the switch without de-energizing the existing bus.

When land availability is a concern, gas-insulated substations (GIS) are a compact, though costly, solution to restricted space requirements. Typically, such installations become more economical in the 230 kV and higher voltages, but contact equipment vendors to determine applicability for a given installation.

21.4.2   Site Work

If the expansion land area was originally set aside for a lower voltage, it has to be enlarged to accommodate the future higher voltage.

Obtain additional soil data in the expansion area. It would be an invalid assumption to take for granted that conditions in the existing site carried on to the expansion area.

Other criteria for site work are covered in Chapter 6, Site Design.

21.4.3   Grounding

Take ground resistivity measurements in the expansion area. These can often be obtained along with the soil data.

A reasonable estimate of ground fault current can be calculated for the proposed higher voltage. Design the grounding system for this higher voltage using the methods described in Chapter 9, Grounding.

21.4.4   Raceway System

If the existing substation employs an underground duct system, this does not in itself mandate the expansion to this method.

As described in Chapter 10, cable trench has certain advantages over ducts. A large handhole can be designed to interface the existing ducts to a trench and the advantages of trench used throughout the expansion area. If the expansion area is later separated from the existing area, the handhole becomes an ideal point of electrical separation.

When the higher voltage level is built, the trench can be paralleled with the other trench for the increased cable requirements with segregation usually occurring at this level.

In substations 230 kV and above, there may be concern with shielding of control cables. Make an effort to provide appropriate shielding and segregation of cables routed in cable trench beneath the high-voltage buses.

21.4.5   Control House

Unless substation expansion was planned in the original design and the control house sized accordingly, it will probably require enlarging. Design the enlargement with the higher, future voltage in mind.

Expansion of the existing control house may or may not be feasible because of physical obstructions or limitations in the construction methods originally used. It may be necessary to build a separate control house, interconnected with the original house by the necessary cable and raceway. Expansion of the existing control house is the preferred method, since it allows for all controls within the same building. Layout of the house should take into consideration the optimum arrangement of control panels to facilitate operations.

21.4.6   Equipment

21.4.6.1   Bus System: Make a conservative estimate of expected fault currents at the higher voltage level and establish the bus BIL along with ground clearances to personnel, roads, and fencing. Following the methods outlined in other chapters, design the bus and insulators at this level taking into account contemplated full load bus current.

21.4.6.2   Transformers and Circuit Breakers: The selection of transformers and circuit breakers together with their associated isolating switches is detailed in other chapters of this guide. Specify this equipment for the operating voltage. Design foundations and switch structures for the higher, future voltage. When the higher voltage becomes a reality, cutover will be more orderly and less time-consuming. Specify disconnecting switches with the phase spacing of the higher level.

21.4.6.3   Carrier Equipment, Surge Arresters, and Voltage Devices: Specify this equipment at the operating voltage. However, foundations and supporting structures can and should be designed for the higher voltage for the reasons set forth previously.

21.4.6.4   Auxiliary Systems: Check and possibly revise or increase in capacity several equipment items in the auxiliary systems to successfully expand an existing substation:

  1. Auxiliary transformer capacity
  2. Throwover switch ratings, full load and momentary
  3. Low-voltage ac and dc panel circuit capacity and adequacy of mains
  4. Low-voltage switchgear circuit capacity
  5. Battery and charger capacity

Redesign or modification of the auxiliary system of the expanded substation is accomplished by summing existing loads with the expansion loads and proceeding as outlined in Chapter 15, AC and DC Auxiliary Systems, for a new installation.

A review of the operating history of the ac system may reveal that the originally assigned demand factors were overly conservative, and the existing capacity may be adequate for the substation expansion.

The same could be true regarding the throwover switch. In the interest of reliability, any deficiency, however slight, indicates replacement of this switch.

Well-designed ac and dc systems should have provided ample spare panel circuits and adequate mains. This may not have been done because no expansion was ever considered possible at the particular installation under consideration. A new panel can be tied directly to the existing panel by doubling the main lugs of the existing unit. Locate the new panel close to the existing and full-ampere capacity cable installed.

Low-voltage switchgear falls into the same category as the panels. Additions can be made in the same way using individual fused switches or circuit breakers.

The dc battery and charger, if not originally specified for equipment additions and/or if found inadequate, should be replaced for the substation expansion.

21.4.6.5   Relaying, Metering and Control: If the same relaying scheme as existing is applied to the substation expansion, the only requirement is the addition of relay panels for the expansion together with associated control panels. In this situation, the metering scheme would undoubtedly remain the same with equipment duplicating the existing equipment.

The different loading conditions of the substation with the expansion may require resetting of the relays of the existing portion. Re-coordination of feeder and bus relaying, as well as evaluation of CT ratios, may be required.

The reason for the expansion program may dictate more complex, sophisticated protective relaying, both for the existing and the expanded substation. A situation such as this is practically identical to a completely new design and should be treated accordingly.

21.5   PLANNING FOR UPRATING OR EXPANSION

All programs involving substation construction require planning. This is especially true of a program of uprating or expansion.

The trend is toward assessment of existing substations and individual equipment to develop a predictive maintenance and substation life extension program. This approach implements a planned program for evaluating substation components and making modifications or individual equipment replacements to improve reliability and extend the overall substation life.

Such a program can be operated in conjunction with uprating or expansion planning to optimize the replacement and maintenance of substation equipment. For instance, major substation uprating or expansion planning might include the replacement of existing electromechanical relays with microprocessor relays for improved substation protection and monitoring.

Reliability analysis is being implemented in many maintenance programs to assess the probability of failures and prioritize modifications based on safety, economics, obsolescence, and power quality.

Maintenance planning should be a part of the early stages of uprating or expansion projects. Such planning includes visual inspections, periodic testing, maintaining of spare parts inventories, logging of equipment test results, and logging of misoperations and maintenance records.

Consider safety issues during the planning stages of any project. Provide and maintain proper tools, personnel protective equipment, safety procedures, and safety training.

A Critical Path Method (CPM) or similar method is recommended for scheduling the actual uprating or expansion activities. Include the detailed activities of engineering, material specification, procurement, manufacturing, and delivery times together with itemized construction activities. The construction work may need to be performed in phases to minimize outage time on particular circuits. Plan required service outages to cause the least revenue loss and customer inconvenience. Factor into the program adequate time to account for contingent delays that can and will occur. Inform customers of forthcoming service outages so they can plan their activities around the outages.

Once the program or plan is developed, assign it to a qualified person to monitor the actual activities, both office and field.

The program will probably require revision as time passes, but with a detailed plan, future problem areas can be detected and appropriate action taken before they become crisis areas.

21.6   COMPARISONS—NEW VS. UPRATING OR EXPANSION

Successful substation uprating will require a high degree of technical cooperation between the cooperative, the engineer, and the manufacturers' staff.

If uprating is just a stop-gap measure to favor a future program, ask the equipment manufacturer to provide a reasonable life estimate of the uprated equipment. This will assist in the priority assignment of the future program.

These comments apply largely to power transformers and, if history of operation shows a minimum of operation above rated temperature, this life estimate can be quite reassuring.

New substation construction obviously causes the least disturbance, electrically, to the customers and the system. In the case of a small installation, expansion can consist of duplicating the existing installation and making a "hot" cutover or otherwise placing the new section in service with minimum outage. In this case, if transformers are being paralleled, other chapters in this guide should be consulted for guidelines.

An expansion to existing facilities is on a par with uprating as to disturbance, but with good planning and management of all phases of the program this can be kept to a minimum.

21.7   SUBSTATION UPGRADING

Substation upgrading by itself is difficult to justify because of the extent and cost of the modifications normally required. However, when coupled with concurrent substation expansion, upgrading can often become the best choice compared with construction of a completely new facility.

Substation modifications or upgrading are warranted when conditions affecting safety or security are evident. Substations, particularly those of early vintage, may not meet current minimum recommended requirements for insulation, electrical clearances, or structural integrity. In these instances, make a thorough examination to determine the most efficient and economical method to improve the situation.

Construction of a new installation with ample provisions for future expansion may be the best choice, particularly if extensive modifications are required.

It should be noted that, because a standards group has lowered permissible operating temperatures or made other standards changes to certain equipment or materials, if no trouble has been experienced and maintenance is properly scheduled on existing equipment installed under the older standards, this equipment need not be arbitrarily replaced.

21.8 REFERENCES

The Aluminum Association, *Aluminum Electrical Conductor Handbook*, New York: The Aluminum Association, 1971.