HV Substation Design: Applications and Considerations

Dominik Pieniazek, P.E.

IEEE CED – Houston Chapter
October 2-3, 2012

IEEE Houston Section

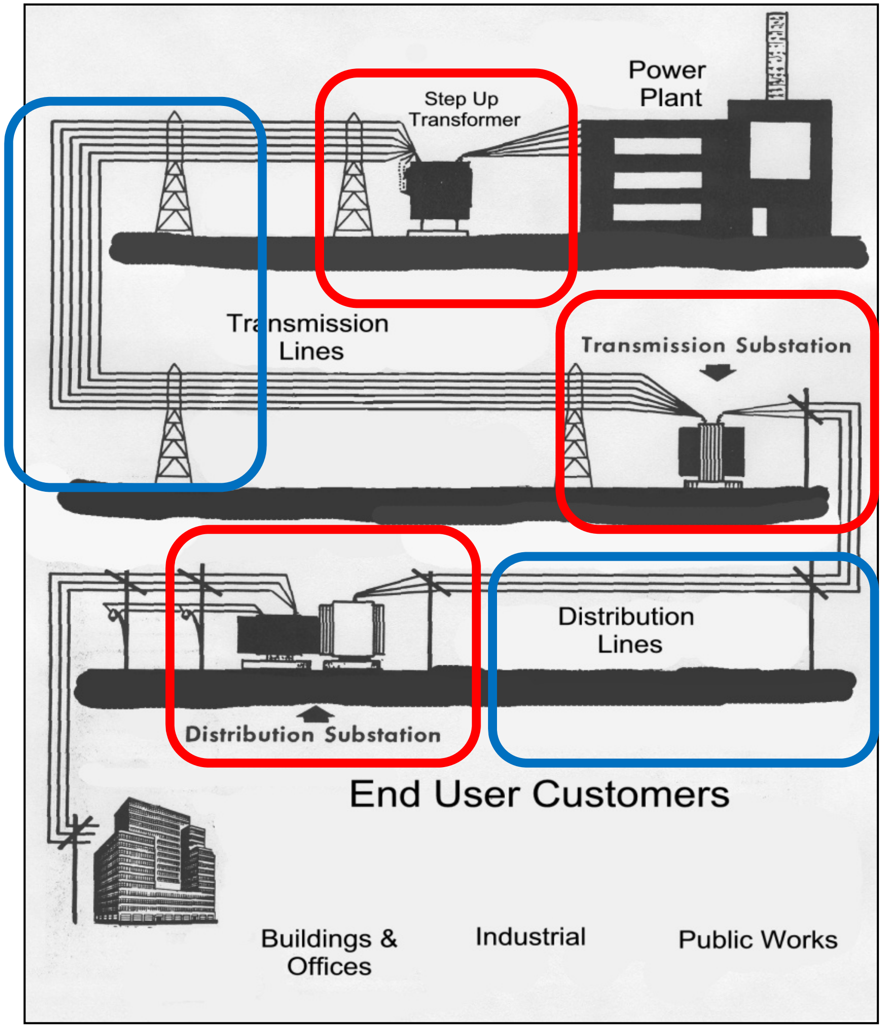
HV
Engineering
www.hv-eng.com

Agenda

- Substation Basics
- Electrical Configuration
- Physical Design
- Protection and Controls
- Design and Construction Coordination

Electrical System

- Substation - A set of equipment reducing the high voltage of electrical power transmission to that suitable for supply to consumers.
- Switching Station - A set of equipment used to tie together two or more electric circuits.

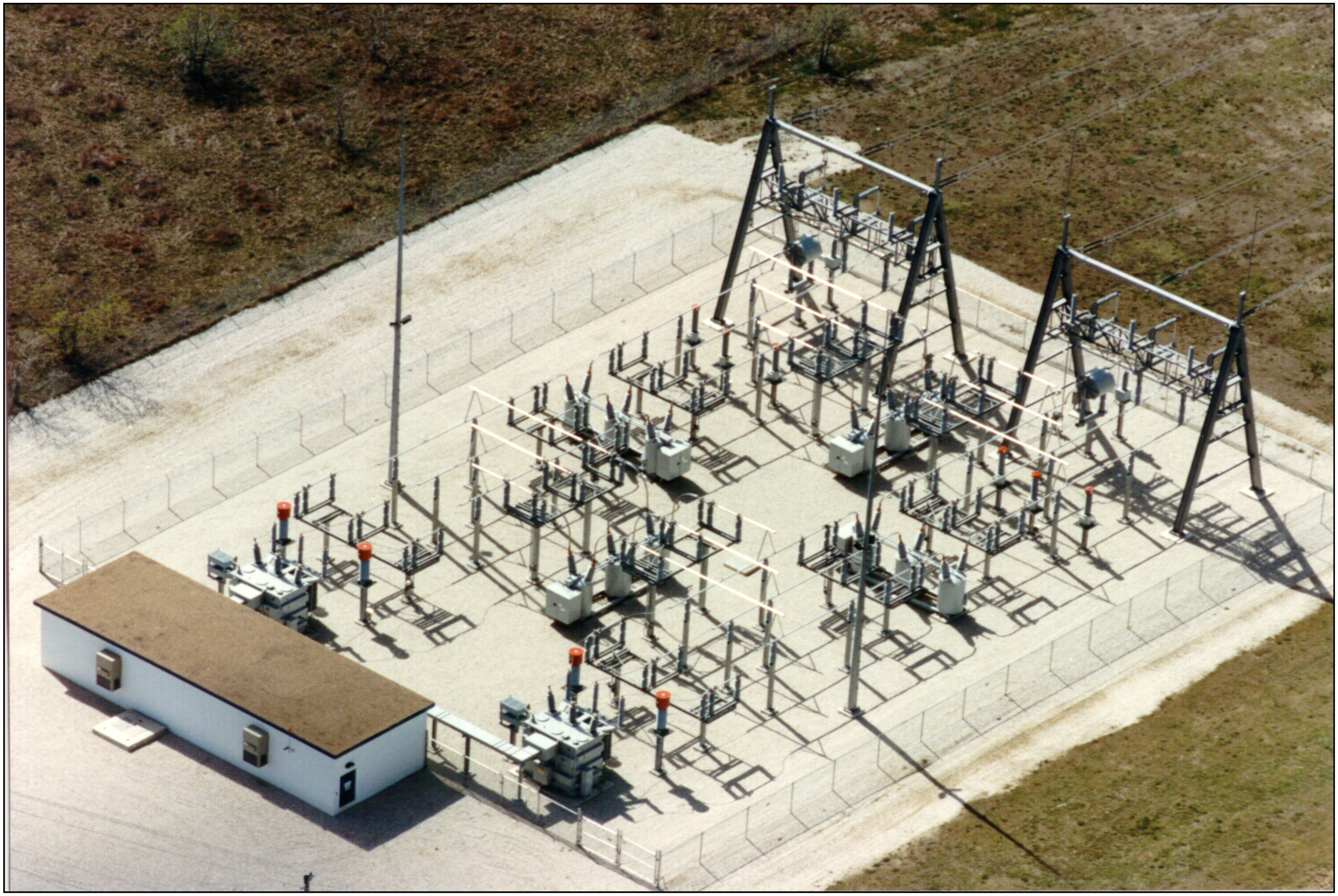


TRANSMISSION LEVEL VOLTAGES

765 kV
500 kV
345 kV
230 kV
161 kV
138 kV
115 kV

DISTRIBUTION LEVEL VOLTAGES

69 kV
46 kV
34.5 kV
23 kV
15 kV
4.16 kV
480 V



Typical 138 kV Substation – Four (4) Breaker Ring Bus w/ Oil Circuit Breakers

Typical 138 kV Substation

Typical 138 kV Substation

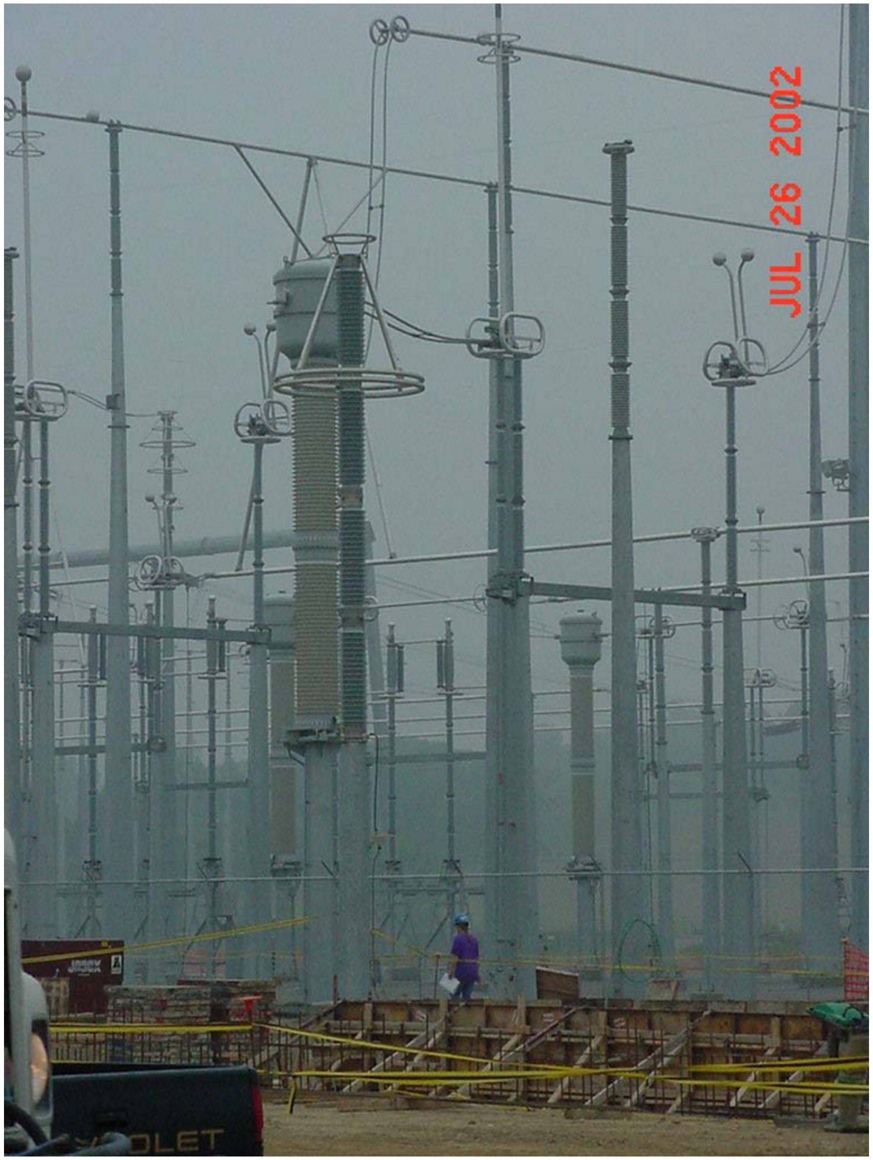
230 kV Generating Substation – Built on the side of a mountain

230 kV Indoor Generating Substation

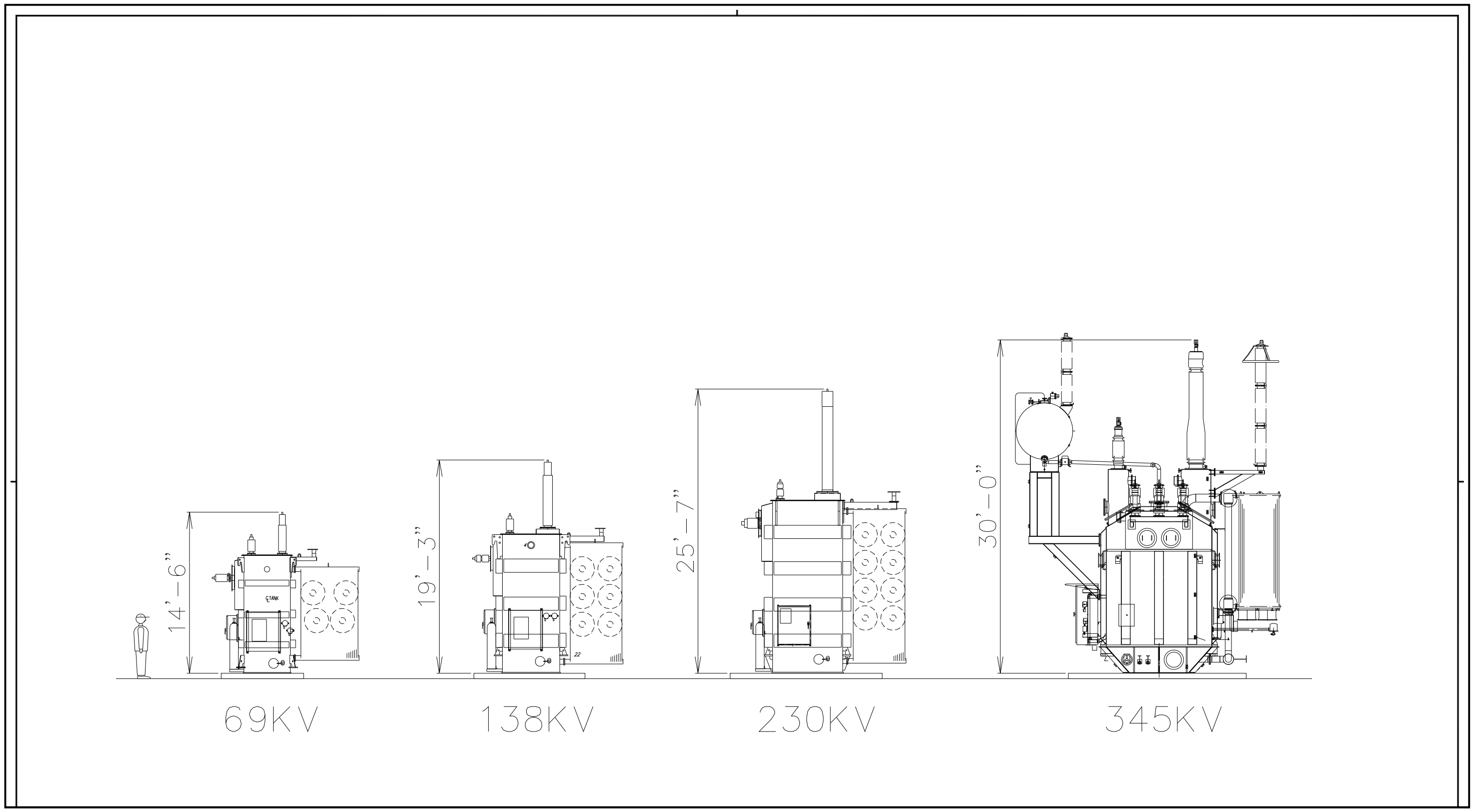
765 kV Generating Substation – Four (4) Breaker Ring Bus w/ Live Tank GCBs

765 kV Generating Substation

765 kV Generating Substation

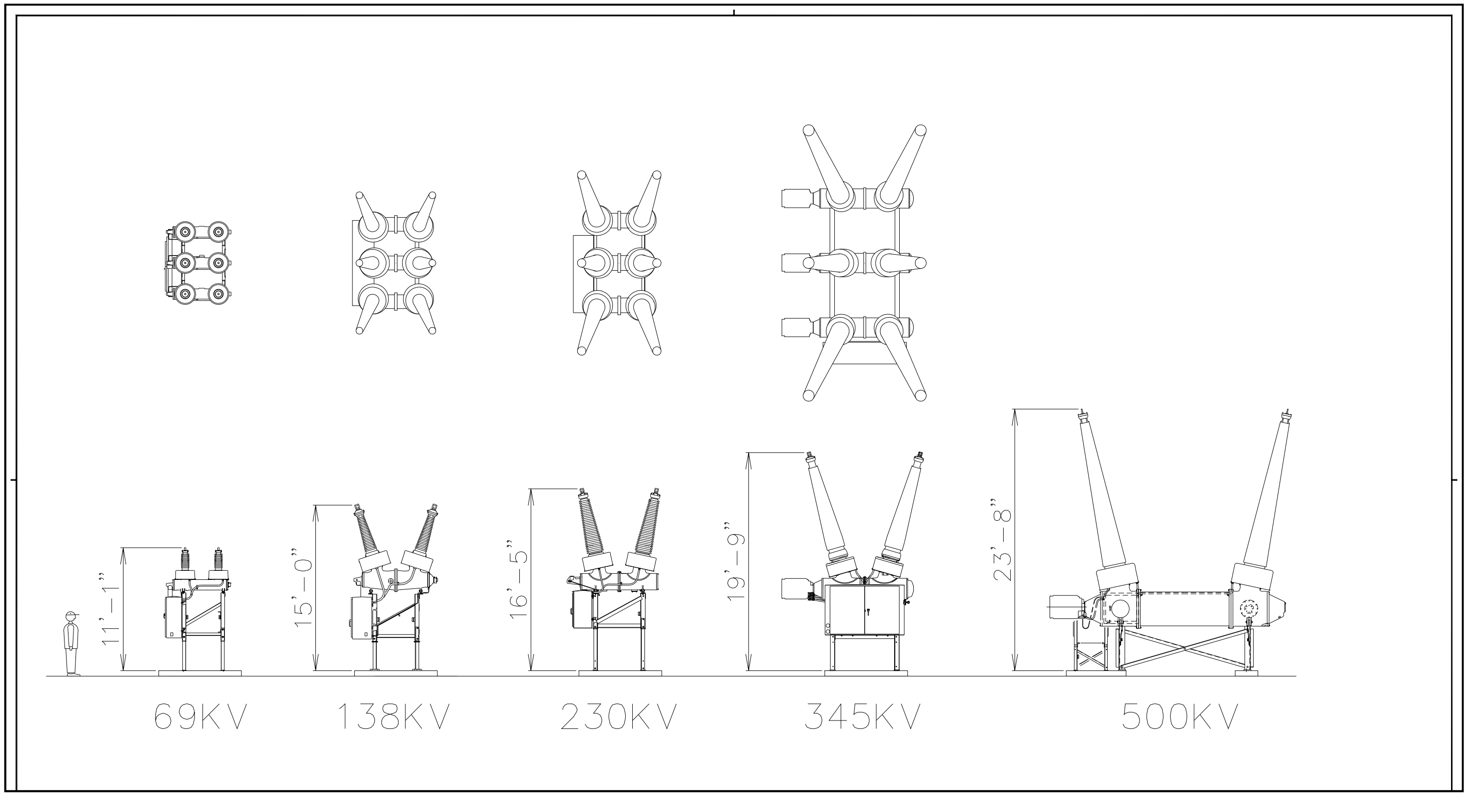


765 kV Generating Substation

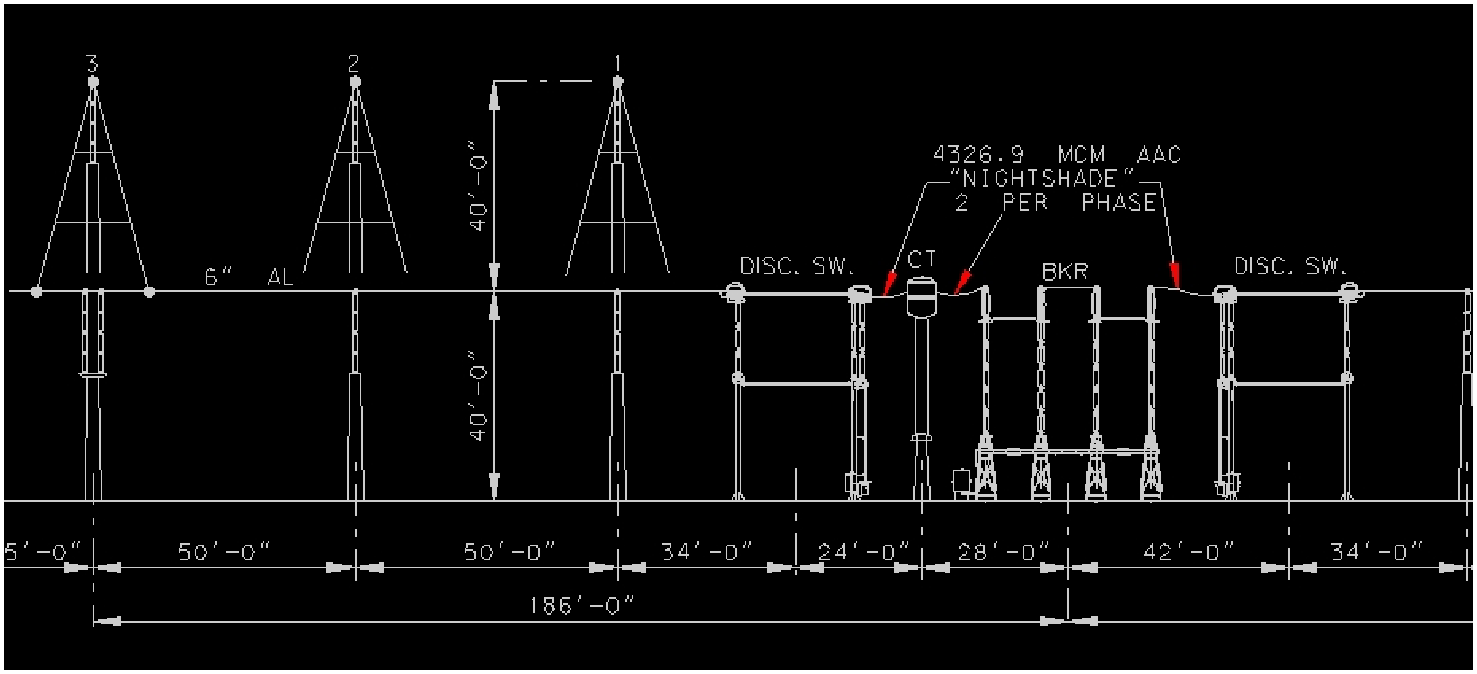


Relative Size of HV Power Transformers

Relative Size of HV and EHV Power Transformers



Relative Size of HV and EHV Gas Circuit Breakers



Dimensions for 765 kV Installation

Where Do I Start My Design?

- Service Conditions?
  - Location, Altitude
  - High and Low Mean Temperatures
  - Temperature Extremes
  - Wind Loading and Ice Loading
  - Seismic Qualifications
  - Area Classification
  - Contamination

Electrical Questions to Address

- Primary System Characteristics?
  - Local Utility
  - Nominal Voltage
  - Maximum Operating Voltage
  - System Frequency
  - System Grounding
  - System Impedance Data

Electrical Questions to Address

- Secondary System Characteristics?
  - Nominal Voltage
  - Maximum Operating Voltage
  - System Grounding

Electrical Questions to Address

- Facility Load/Generation Characteristics?
  - Load Type
  - Average Running Load
  - Maximum Running Load
  - On-Site Generation
  - Future Load Growth
  - Harmonic Loads

Electrical Questions to Address

Equipment Ratings

- Insulation Requirements
  - BIL
  - Insulator and Bushing Creep
  - Minimum Clearances
  - Phase Spacing
  - Arrester Duty
- Current Requirements
  - Rated Continuous Current
  - Maximum 3-Phase Short-Circuit Current
  - Maximum Phase-to-Ground Short-Circuit Current

- Contamination Levels

Multiplier applied to
phase-to-ground voltage

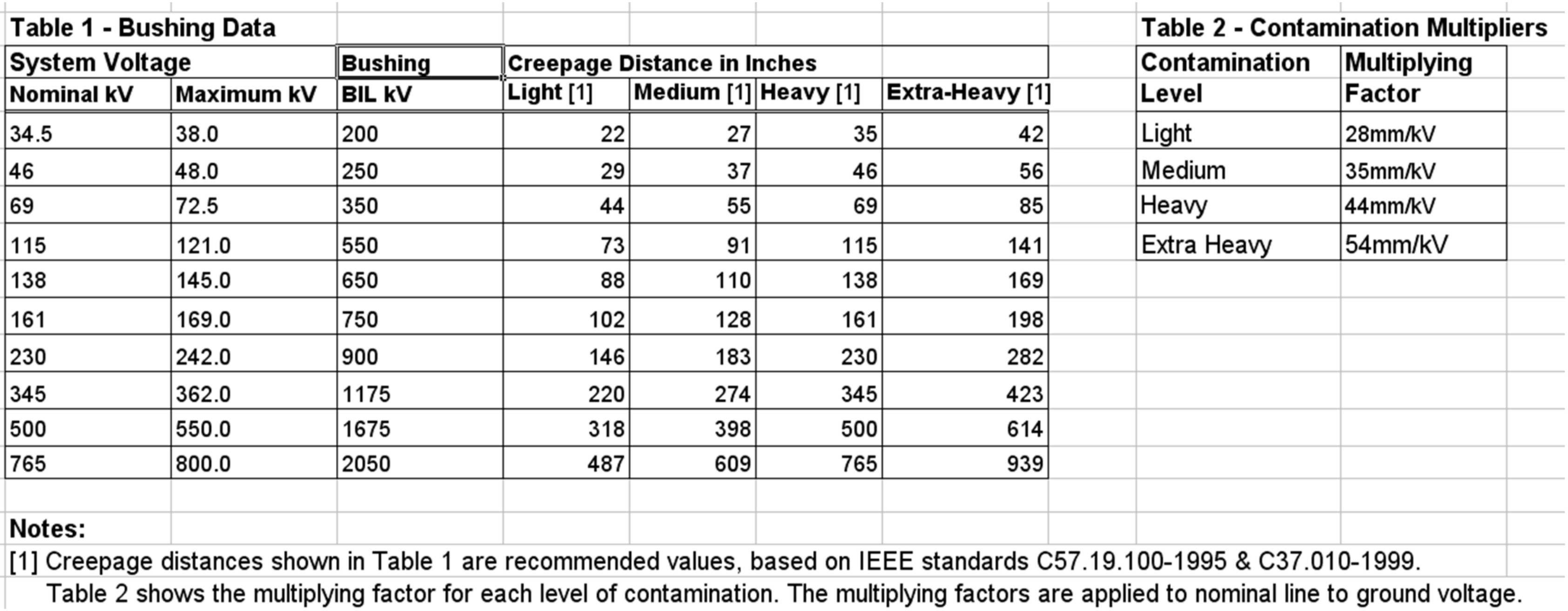


Table 1 - Bushing Data

System Voltage		Bushing	Creepage Distance in Inches			
Nominal kV	**Maximum kV**	**BIL kV**	**Light** [1]	**Medium** [1]	**Heavy** [1]	**Extra-Heavy** [1]
34.5	38.0	200	22	27	35	42
46	48.0	250	29	37	46	56
69	72.5	350	44	55	69	85
115	121.0	550	73	91	115	141
138	145.0	650	88	110	138	169
161	169.0	750	102	128	161	198
230	242.0	900	146	183	230	282
345	362.0	1175	220	274	345	423
500	550.0	1675	318	398	500	614
765	800.0	2050	487	609	765	939

Table 2 - Contamination Multipliers

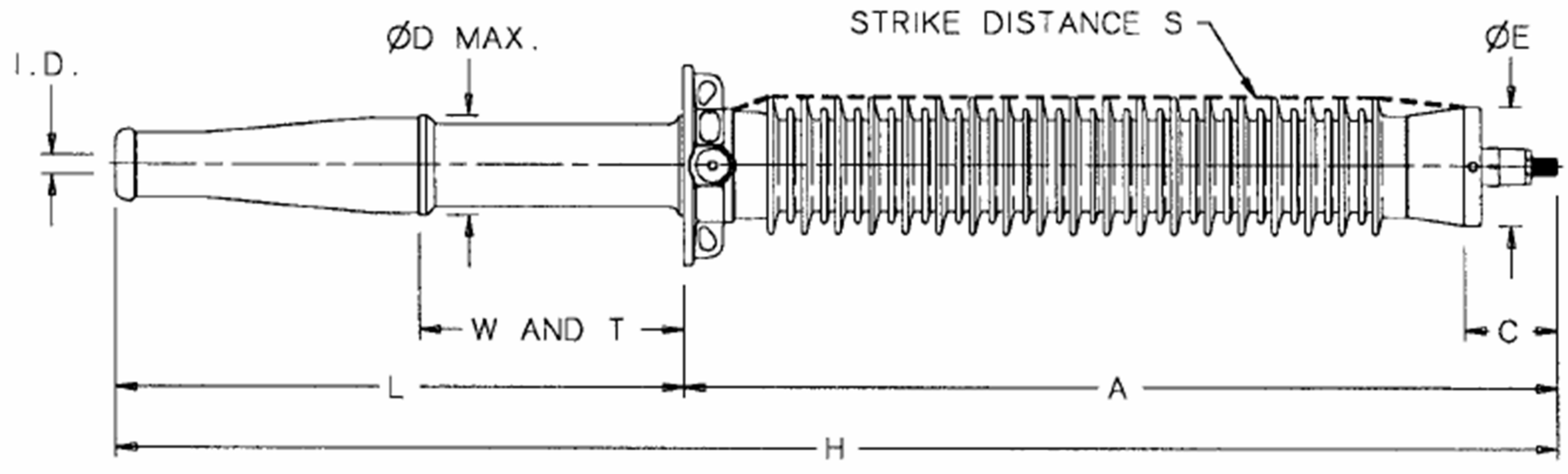
Contamination Level	Multiplying Factor
Light	28mm/kV
Medium	35mm/kV
Heavy	44mm/kV
Extra Heavy	54mm/kV

Notes:

[1] Creepage distances shown in Table 1 are recommended values, based on IEEE standards C57.19.100-1995 & C37.010-1999.
Table 2 shows the multiplying factor for each level of contamination. The multiplying factors are applied to nominal line to ground voltage.

Physical Questions to Address

Typical Draw-Lead Bushing



BUSHING DETAIL

Physical Questions to Address

Electrical Studies

- Power/Load Flow
- Short-Circuit / Device Evaluation
- Device Coordination
- Arc-Flash Hazard Assessment
- Motor Starting, Transient Stability
- Insulation Coordination
- Harmonic Analysis

- Substation Layout Considerations?
  - Available Real Estate
  - Substation Configuration
  - Necessary Degree of Reliability and Redundancy
  - Number of Incoming Lines
  - Proximity to Transmission Lines and Loads

Physical Questions to Address

- Utility Requirements?
  - Application of Utility Specifications
  - Application of Utility Standards
  - Application of Utility Protection and Control Schemes
  - SCADA/RTU Interface
  - Metering Requirements
- Communication/Monitoring Requirements
  - Manned or Unmanned
  - Power Management/Trending
  - Fault Recording
  - Local & Remote Annunciation
  - Local & Remote Control
  - Automation
  - Communication Protocol

Other Questions to Address

- Other Studies / Field Tests
  - Soil Boring Results – Foundation Design
  - Soil Resistivity – Ground Grid Design
  - Spill Prevention, Control, and Countermeasure (SPCC) Plans - Contamination
  - Stormwater Pollution Prevention Plan (SWPPP) - Runoff During Construction
  - Stormwater Management – Detention Pond Requirements

Other Questions to Address

- Budgeted Capital for Substation
- Required Power (1 MVA, 10 MVA, 100 MVA)
- Effect of Power Loss on Process and/or Safety
- Associated Outage Cost (Lost Revenue)
- Future Growth Considerations
- Reliability Study
    - Estimate Cost of Alternate Designs
    - Determine Lost Revenue During Outages
    - Calculate Probability of Outage Based on Design
    - Compare Cost, Lost Revenues, and Outage Probabilities

Major Factors in Substation Selection

Electrical Configuration

- Single Breaker Arrangements
    - Tap Substation
    - Single Breaker Single Bus
    - Operating/Transfer Bus
- Multiple Breaker Arrangements
    - Ring Bus
    - Breaker and a Half
    - Double Breaker Double Bus

Configuration	Relative Cost Comparison
Single Breaker-Single Bus	100% 120% (with sect. breaker)
Main-Transfer Bus	140%
Ring Bus	125%
Breaker and Half	145%
Double Breaker-Double Bus	190%

Reference: IEEE 605-2008

It should be noted that these figures are estimated for discussion purposes. Actual costs vary depending on a number of variables, including:

- Real Estate Costs
- Complexity of Protective Relaying Schemes
- Raw material costs
- Local Labor Costs

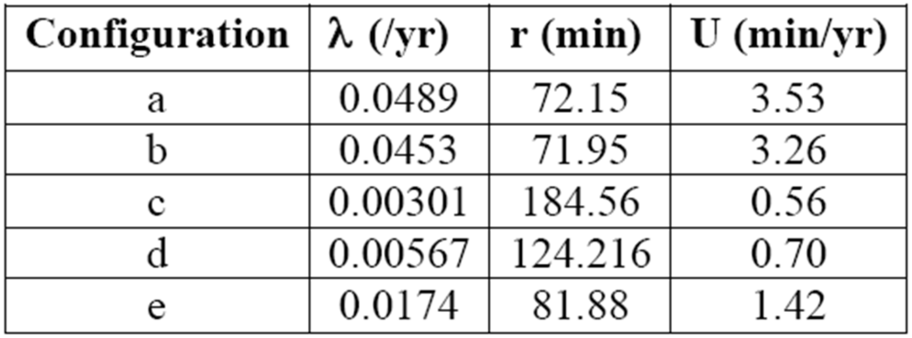
λ = Annual Fail Rate

r = Annual Outage Time

U = Average Outage Time

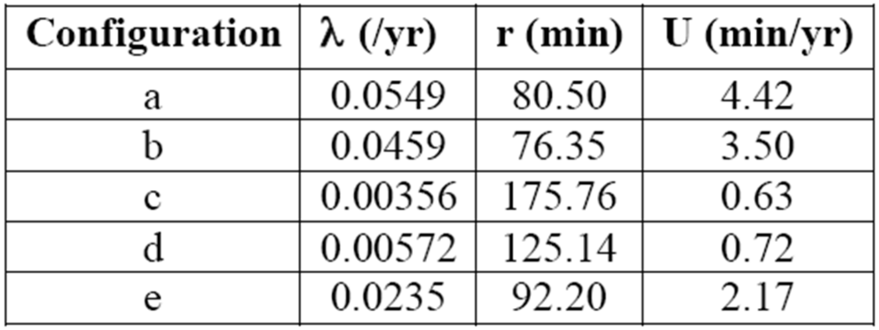
a. Single bus
b. Sectionalized single bus
c. Breaker-and-a-half
d. Double breaker-double bus
e. Ring bus

Table 3: Substation Reliability Indices (Ignoring Line Failure)



Configuration	λ (/yr)	r (min)	U (min/yr)
a	0.0489	72.15	3.53
b	0.0453	71.95	3.26
c	0.00301	184.56	0.56
d	0.00567	124.216	0.70
e	0.0174	81.88	1.42

Table 4: Substation Reliability Indices (Including Line Failures)



Configuration	λ (/yr)	r (min)	U (min/yr)
a	0.0549	80.50	4.42
b	0.0459	76.35	3.50
c	0.00356	175.76	0.63
d	0.00572	125.14	0.72
e	0.0235	92.20	2.17

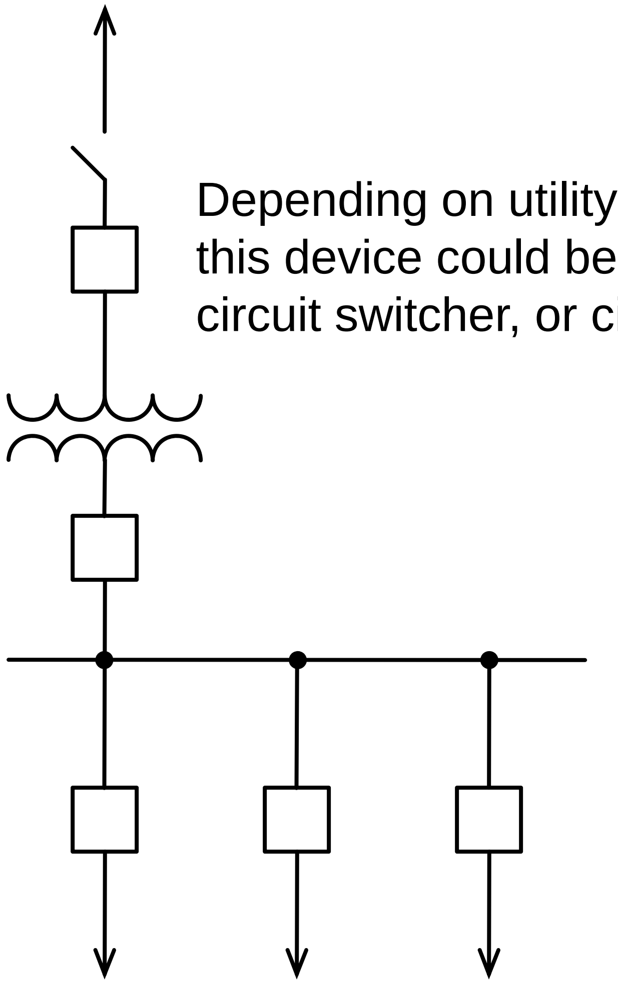
Reference: “Reliability of Substation Configurations”, Daniel Nack, Iowa State University, 2005

Reliability Models

- IEEE Gold Book
- For high voltage equipment data is a “generic” small sample set
- Sample set collected in minimal certain conditions (i.e. what really caused the outage)
- Calculated indices may not represent reality…

A great reference is John Propst’s 2000 PCIC Paper "IMPROVEMENTS IN MODELING AND EVALUATION OF ELECTRICAL POWER SYSTEM *RELIABILITY*"

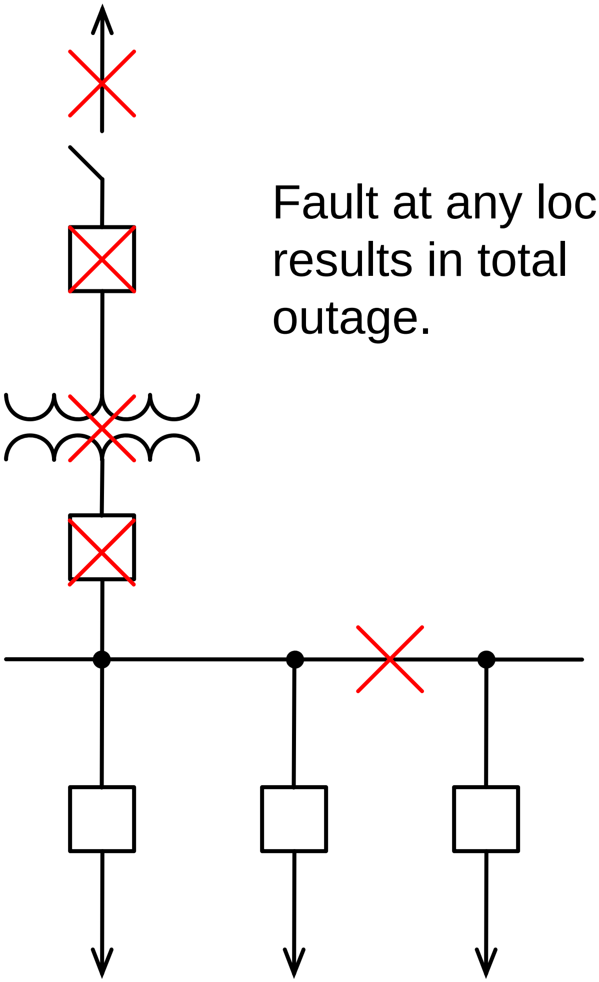
- Most Basic Design
- Tapped Line is Source of Power
- Interrupting Device Optional but Recommended
- No Operating Flexibility



Depending on utility voltage, this device could be a fuse, circuit switcher, or circuit breaker

Tap Substation

- Most Basic Design
- Tapped Line is Source of Power
- Interrupting Device Optional but Recommended
- No Operating Flexibility



Fault at any location results in total outage.

Tap Substation

Tap Substation

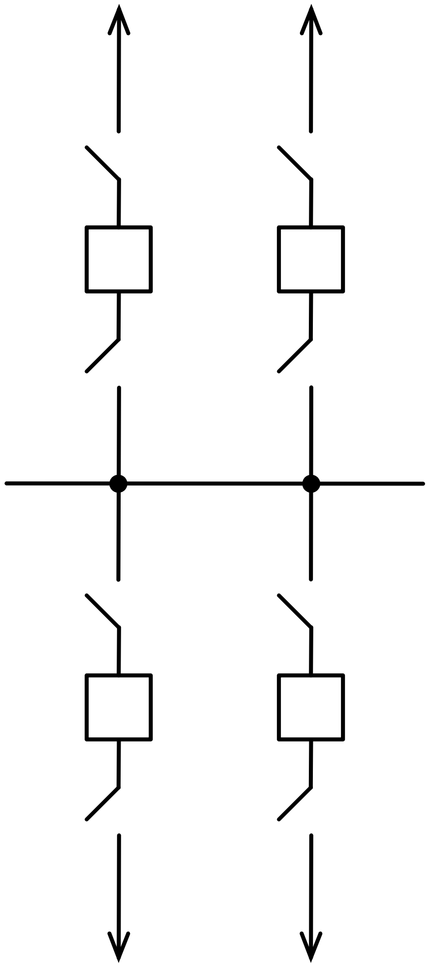
Pros

- Small Plot Size
- Low Initial Cost
- Low Maintenance Costs

Cons

- Line Operations Result in Plant Outages
- Multiple Single Points of Failure
- Failure Points are in Series
- Outages Expected
- Line Faults Cleared by Others
- Low Maintainability

Single Breaker Single Bus Substation



- Basic Design
- One Circuit Breaker per Circuit
- One Common Bus
- No Operating Flexibility
- Widely Used at Distribution Level
- Limited Use at High Voltage

Pros

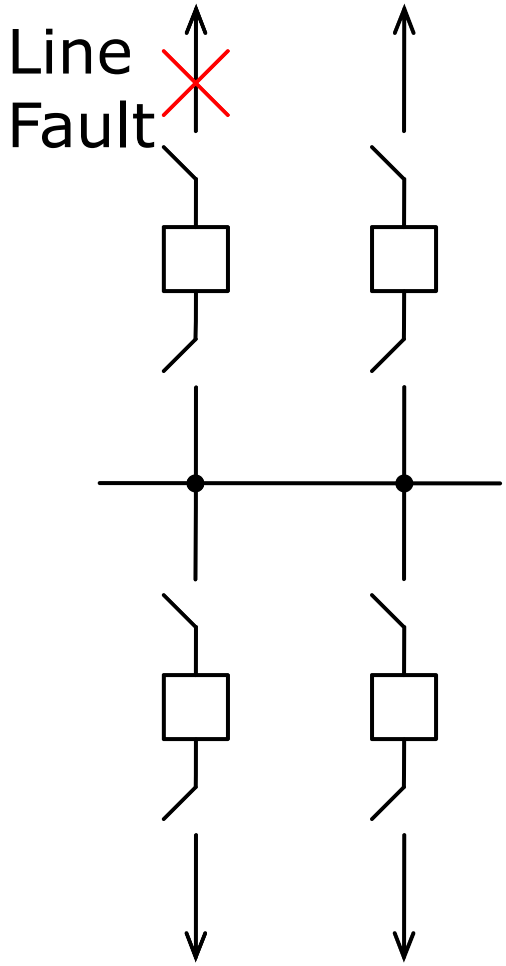
- Each Circuit has Breaker
- Only One Set of VTs Required
- Simple Design

Cons

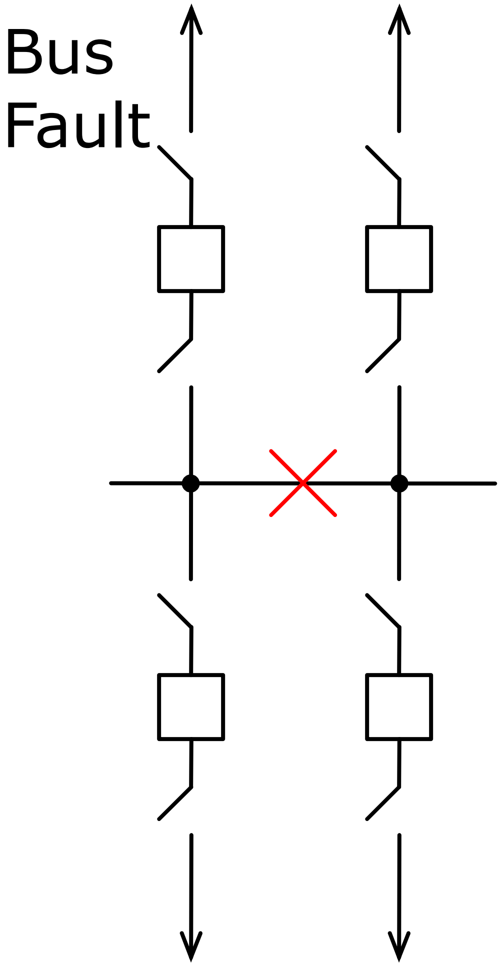
- Circuit Breaker Maintenance Requires Circuit Outage
- Bus Fault Clears all Circuits
- Breaker Failure Clears all Circuits
- Single Points of Failure Between Circuits are in Series
- Expansion requires complete station outage

Single Breaker Single Bus

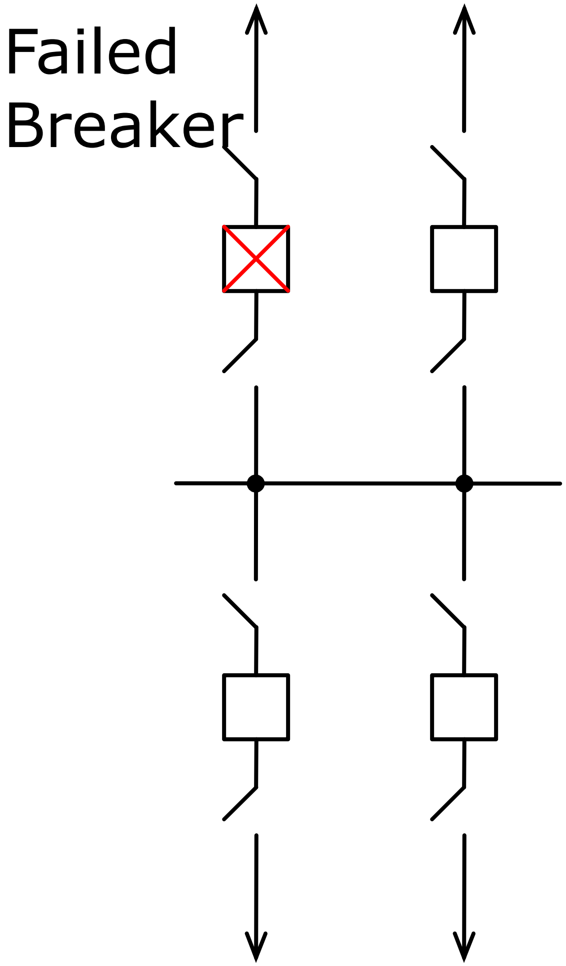
Single Breaker Single Bus



Line
Fault



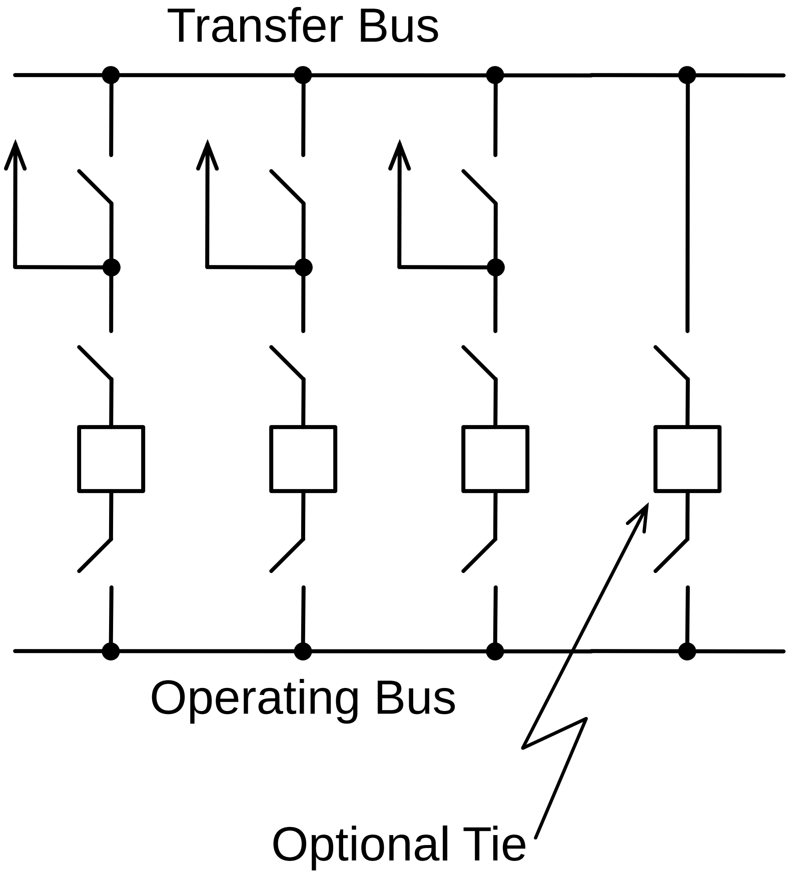
Bus
Fault



Failed
Breaker

Operating/Transfer Buses with Single Breaker

- Similar to Single Breaker Single Bus
- Add Transfer Bus
- Transfer Bus Switches Normally Open
- Only 1 Circuit Operated From Transfer Bus
- Widely Used in Outdoor Distribution Applications



Operating/Transfer Buses with Single Breaker

Pros

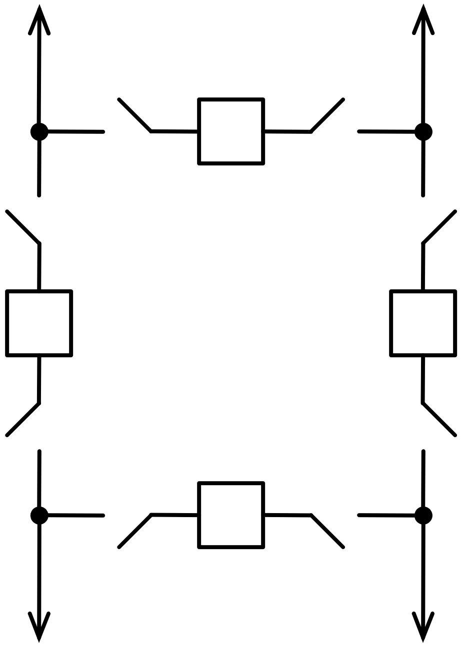
- Breaker Maintenance w/o Circuit Interruption
- Only One Set of VTs Required

Cons

- More Costly with Addition of Transfer Bus
- Adaptable Protection is Necessary
- If Not Adaptable, Protection Compromise During Maintenance
- Normal Operation Is Single Breaker Single Bus

Ring Bus

- Popular at High Voltage
- Circuits and Breakers Alternate in Position
- No Buses per se



Pros

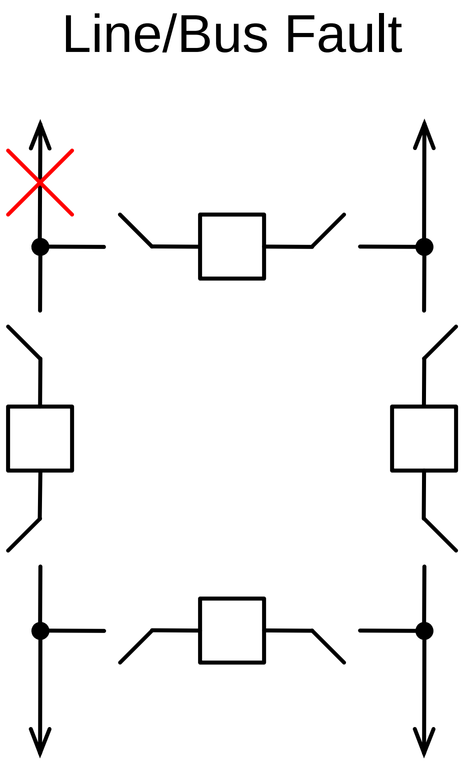
- High Flexibility with Minimum of Breakers
- Dedicated Bus Protection not Required
- Highly Adaptable
- Failed Circuit Does Not Disrupt Other Circuits
- Breaker Maintenance w/o Circuit Interruption

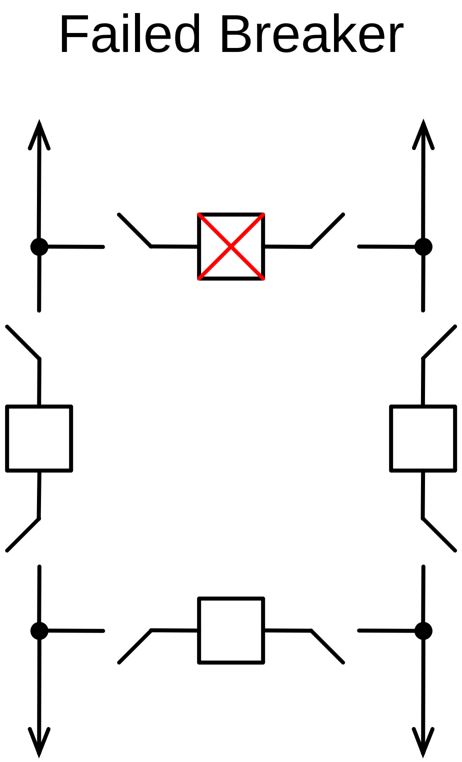
Cons

- Failed Breaker May Result in Loss of Multiple Circuits
- Physically Large With 6 or More Circuits

Ring Bus

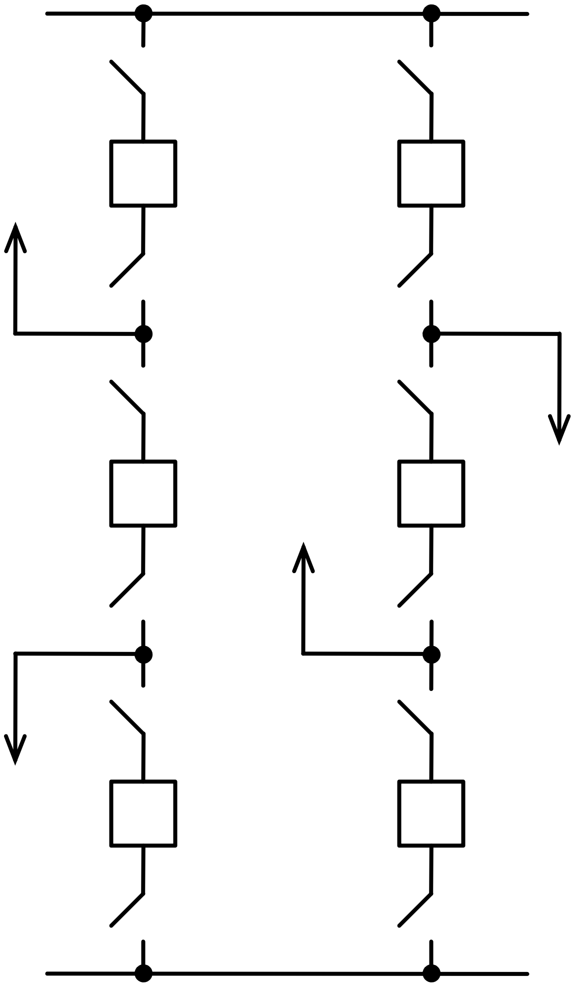
Ring Bus


Line/Bus Fault


Failed Breaker

Breaker-And-A-Half

- More Operating Flexibility than Ring Bus
- Requires 3 Breakers for Every Two Circuits
- Widely Used at High Voltage, Especially Where Multiple Circuits Exist (e.g. Generating Plants)



Pros

- Robust
- Highly Expandable
- Failed Outer Breakers Result in Loss of One Circuit Only
- Breaker Maintenance w/o Circuit Interruption

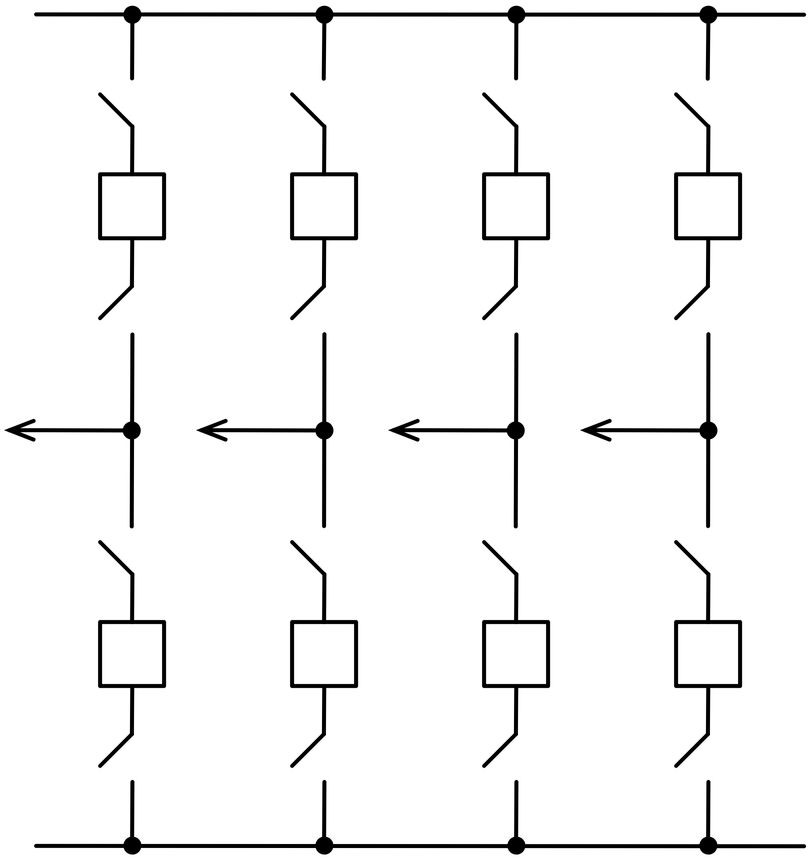
Cons

- Cost
- Physically Large
- Failed Center Breaker Results in Loss of Two Circuits

Breaker-And-A-Half

Double Breaker Double Bus

- Highly Flexible Arrangement
- Two Buses, Each Separated by Two Circuit Breakers
- Two Circuit Breakers per Circuit
- All Breakers Normally Closed



Pros

- Bus Faults Do Not Interrupt Any Circuit
- Circuit Faults Do Not Interrupt Any Buses or Other Circuits
- Failed Breaker Results in Loss of One Circuit Only
- Breaker Maintenance w/o Circuit Interruption
- Highly Expandable
- Robust

Cons

- Cost – Two Breakers & Four Switches per Circuit
- Physical Size

Double Breaker Double Bus

Physical Arrangement

- NEMA SG-6
    - Withdrawn, but still used by many
    - BIL Based
    - Provides
        - Bus spacings
        - Horn Gap Spacings
        - Side Break Switch Spacings
        - Minimum Metal-to-Metal
        - Minimum Phase-to-Ground

Spacing & Clearances

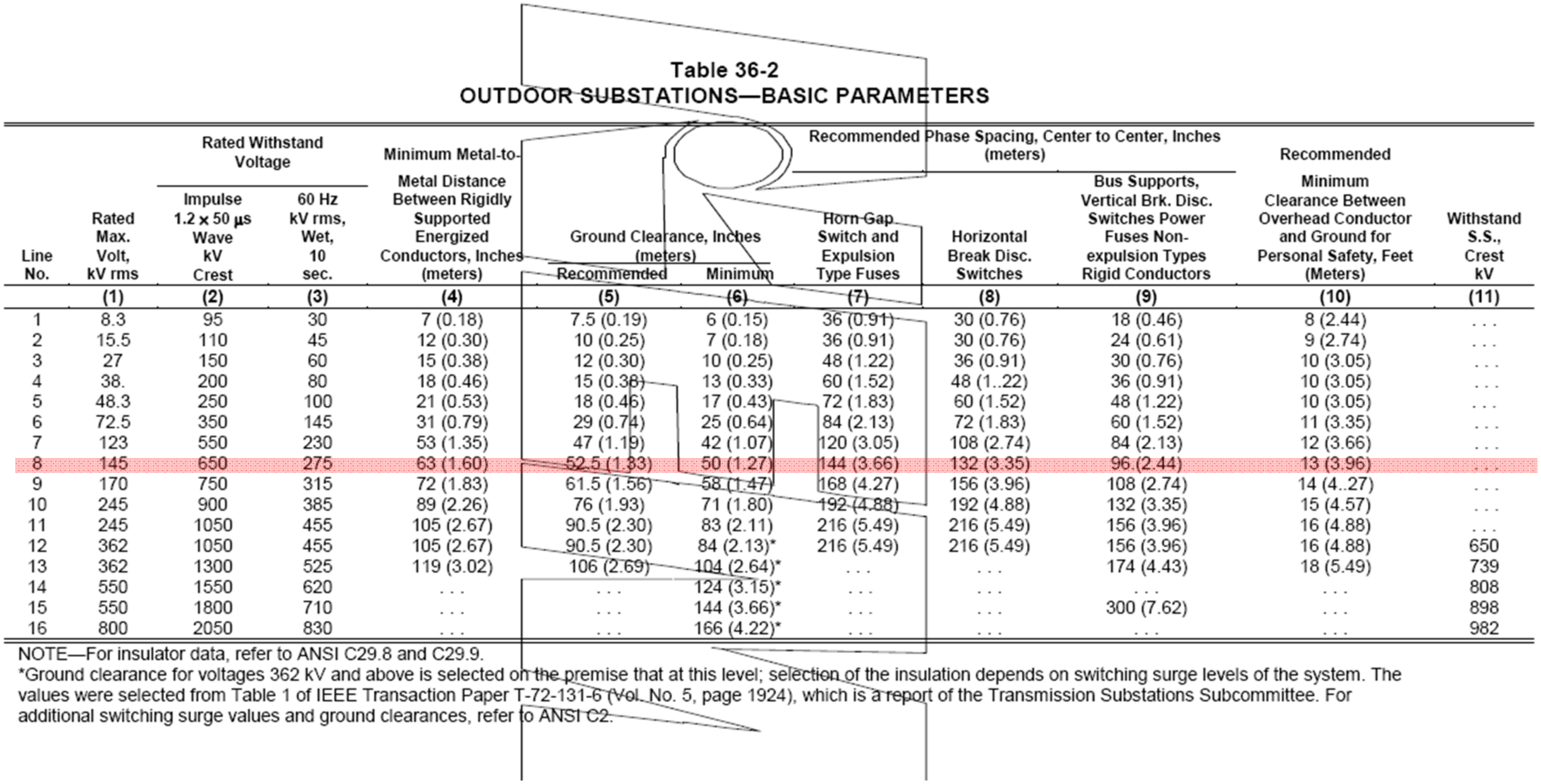


Table 36-2

OUTDOOR SUBSTATIONS—BASIC PARAMETERS

Line No.	Rated Max. Volt, kV rms	Rated Withstand Voltage		Minimum Metal-to-Metal Distance Between Rigidly Supported Energized Conductors, Inches (meters)	Ground Clearance, Inches (meters)		Recommended Phase Spacing, Center to Center, Inches (meters)			Recommended Minimum Clearance Between Overhead Conductor and Ground for Personal Safety, Feet (Meters)	Withstand S.S., Crest kV
		Impulse 1.2 × 50 µs Wave kV Crest	60 Hz kV rms, Wet, 10 sec.		Recommended	Minimum	Horn Gap Switch and Expulsion Type Fuses	Horizontal Break Disc. Switches	Bus Supports, Vertical Brk. Disc. Switches Power Fuses Non-expulsion Types Rigid Conductors		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	8.3	95	30	7 (0.18)	7.5 (0.19)	6 (0.15)	36 (0.91)	30 (0.76)	18 (0.46)	8 (2.44)	. . .
2	15.5	110	45	12 (0.30)	10 (0.25)	7 (0.18)	36 (0.91)	30 (0.76)	24 (0.61)	9 (2.74)	. . .
3	27	150	60	15 (0.38)	12 (0.30)	10 (0.25)	48 (1.22)	36 (0.91)	30 (0.76)	10 (3.05)	. . .
4	38.	200	80	18 (0.46)	15 (0.38)	13 (0.33)	60 (1.52)	48 (1..22)	36 (0.91)	10 (3.05)	. . .
5	48.3	250	100	21 (0.53)	18 (0.46)	17 (0.43)	72 (1.83)	60 (1.52)	48 (1.22)	10 (3.05)	. . .
6	72.5	350	145	31 (0.79)	29 (0.74)	25 (0.64)	84 (2.13)	72 (1.83)	60 (1.52)	11 (3.35)	. . .
7	123	550	230	53 (1.35)	47 (1.19)	42 (1.07)	120 (3.05)	108 (2.74)	84 (2.13)	12 (3.66)	. . .
8	145	650	275	63 (1.60)	52.5 (1.33)	50 (1.27)	144 (3.66)	132 (3.35)	96 (2.44)	13 (3.96)	. . .
9	170	750	315	72 (1.83)	61.5 (1.56)	58 (1.47)	168 (4.27)	156 (3.96)	108 (2.74)	14 (4..27)	. . .
10	245	900	385	89 (2.26)	76 (1.93)	71 (1.80)	192 (4.88)	192 (4.88)	132 (3.35)	15 (4.57)	. . .
11	245	1050	455	105 (2.67)	90.5 (2.30)	83 (2.11)	216 (5.49)	216 (5.49)	156 (3.96)	16 (4.88)	. . .
12	362	1050	455	105 (2.67)	90.5 (2.30)	84 (2.13)*	216 (5.49)	216 (5.49)	156 (3.96)	16 (4.88)	650
13	362	1300	525	119 (3.02)	106 (2.69)	104 (2.64)*	. . .	. . .	174 (4.43)	18 (5.49)	739
14	550	1550	620	. . .	. . .	124 (3.15)*	. . .	. . .	. . .	. . .	808
15	550	1800	710	. . .	. . .	144 (3.66)*	. . .	. . .	300 (7.62)	. . .	898
16	800	2050	830	. . .	. . .	166 (4.22)*	. . .	. . .	. . .	. . .	982

NOTE—For insulator data, refer to ANSI C29.8 and C29.9.

*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. No. 5, page 1924), which is a report of the Transmission Substations Subcommittee. For additional switching surge values and ground clearances, refer to ANSI C2.

Spacing & Clearances

- IEEE 1427-2006 – Guide for Electrical Clearances & Insulation Levels in Air Insulated Electrical Power Substations
  - BIL/BSL Based
  - Rec. Phase-to-Phase
  - Min. Metal-to-Metal
  - Min. Phase to Ground
  - Rec. Bus Spacings including Horn Gap

Spacing & Clearances

Spacing & Clearances

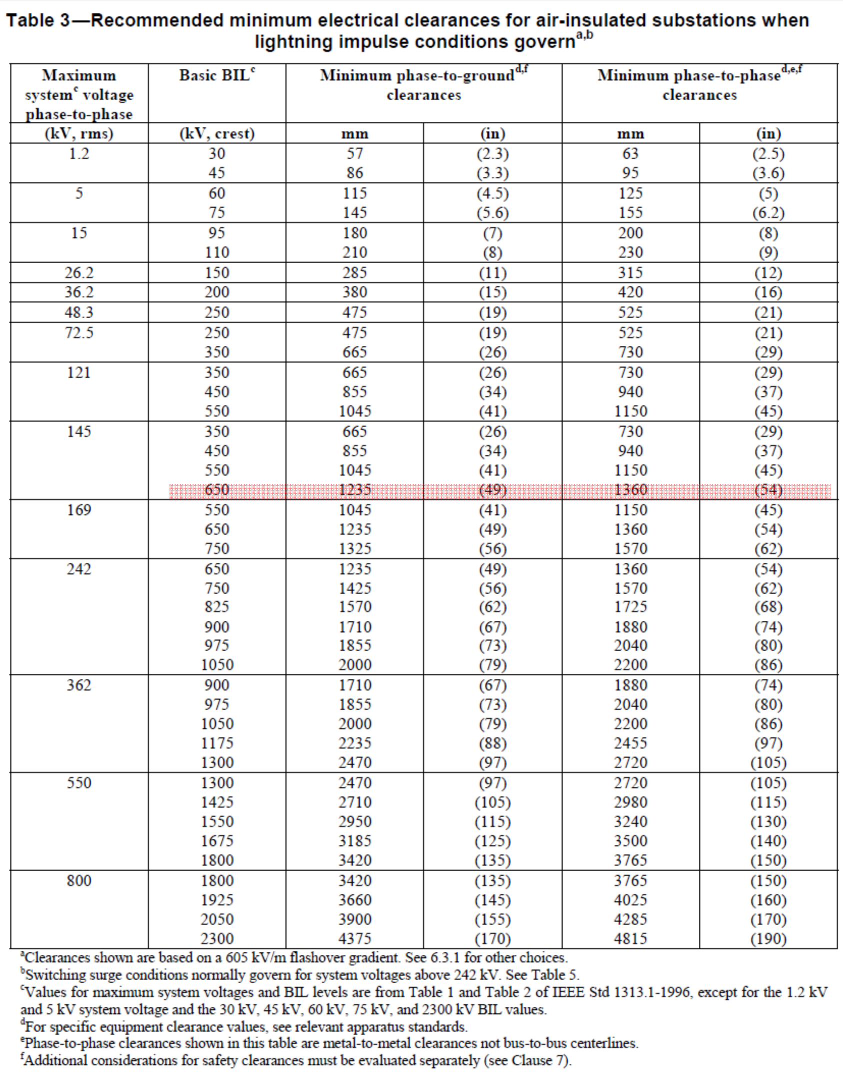


Table 3—Recommended minimum electrical clearances for air-insulated substations when lightning impulse conditions govern[a,b]

Maximum system[c] voltage phase-to-phase	Basic BIL[c]	Minimum phase-to-ground[d,f] clearances		Minimum phase-to-phase[d,e,f] clearances	
(kV, rms)	(kV, crest)	mm	(in)	mm	(in)
1.2	30	57	(2.3)	63	(2.5)
	45	86	(3.3)	95	(3.6)
5	60	115	(4.5)	125	(5)
	75	145	(5.6)	155	(6.2)
15	95	180	(7)	200	(8)
	110	210	(8)	230	(9)
26.2	150	285	(11)	315	(12)
36.2	200	380	(15)	420	(16)
48.3	250	475	(19)	525	(21)
72.5	250	475	(19)	525	(21)
	350	665	(26)	730	(29)
121	350	665	(26)	730	(29)
	450	855	(34)	940	(37)
	550	1045	(41)	1150	(45)
145	350	665	(26)	730	(29)
	450	855	(34)	940	(37)
	550	1045	(41)	1150	(45)
	650	1235	(49)	1360	(54)
169	550	1045	(41)	1150	(45)
	650	1235	(49)	1360	(54)
	750	1325	(56)	1570	(62)
242	650	1235	(49)	1360	(54)
	750	1425	(56)	1570	(62)
	825	1570	(62)	1725	(68)
	900	1710	(67)	1880	(74)
	975	1855	(73)	2040	(80)
	1050	2000	(79)	2200	(86)
362	900	1710	(67)	1880	(74)
	975	1855	(73)	2040	(80)
	1050	2000	(79)	2200	(86)
	1175	2235	(88)	2455	(97)
	1300	2470	(97)	2720	(105)
550	1300	2470	(97)	2720	(105)
	1425	2710	(105)	2980	(115)
	1550	2950	(115)	3240	(130)
	1675	3185	(125)	3500	(140)
	1800	3420	(135)	3765	(150)
800	1800	3420	(135)	3765	(150)
	1925	3660	(145)	4025	(160)
	2050	3900	(155)	4285	(170)
	2300	4375	(170)	4815	(190)

[a] Clearances shown are based on a 605 kV/m flashover gradient. See 6.3.1 for other choices.
[b] Switching surge conditions normally govern for system voltages above 242 kV. See Table 5.
[c] Values for maximum system voltages and BIL levels are from Table 1 and Table 2 of IEEE Std 1313.1-1996, except for the 1.2 kV and 5 kV system voltage and the 30 kV, 45 kV, 60 kV, 75 kV, and 2300 kV BIL values.
[d] For specific equipment clearance values, see relevant apparatus standards.
[e] Phase-to-phase clearances shown in this table are metal-to-metal clearances not bus-to-bus centerlines.
[f] Additional considerations for safety clearances must be evaluated separately (see Clause 7).

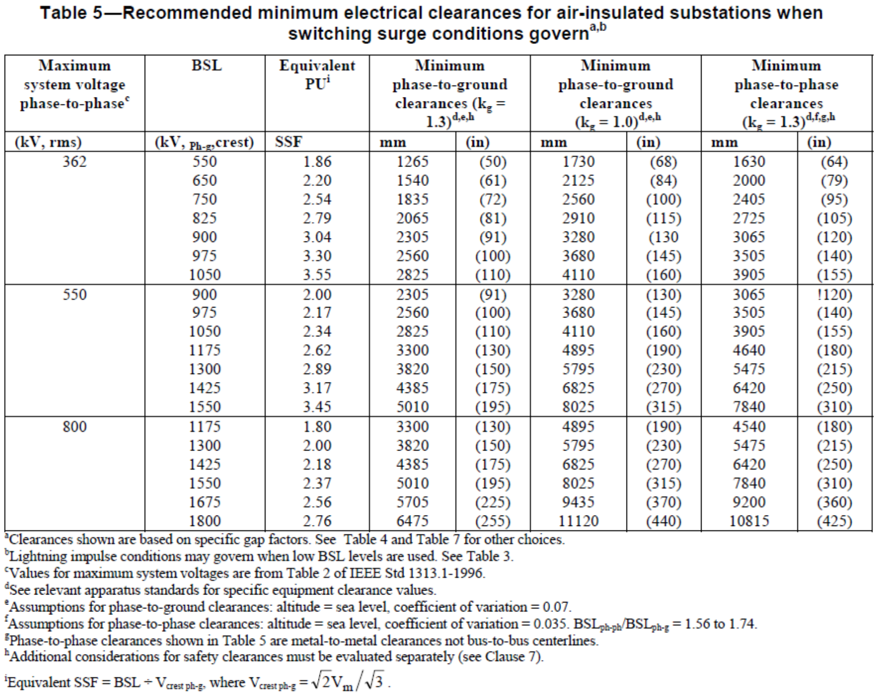


Table 5—Recommended minimum electrical clearances for air-insulated substations when switching surge conditions govern[a,b]

Maximum system voltage phase-to-phase[c]	BSL	Equivalent PU[i]	Minimum phase-to-ground clearances (k_g = 1.3)[d,e,h]		Minimum phase-to-ground clearances (k_g = 1.0)[d,e,h]		Minimum phase-to-phase clearances (k_g = 1.3)[d,f,g,h]	
(kV, rms)	(kV, $_{Ph-g}$, crest)	SSF	mm	(in)	mm	(in)	mm	(in)
362	550	1.86	1265	(50)	1730	(68)	1630	(64)
	650	2.20	1540	(61)	2125	(84)	2000	(79)
	750	2.54	1835	(72)	2560	(100)	2405	(95)
	825	2.79	2065	(81)	2910	(115)	2725	(105)
	900	3.04	2305	(91)	3280	(130	3065	(120)
	975	3.30	2560	(100)	3680	(145)	3505	(140)
	1050	3.55	2825	(110)	4110	(160)	3905	(155)
550	900	2.00	2305	(91)	3280	(130)	3065	!120)
	975	2.17	2560	(100)	3680	(145)	3505	(140)
	1050	2.34	2825	(110)	4110	(160)	3905	(155)
	1175	2.62	3300	(130)	4895	(190)	4640	(180)
	1300	2.89	3820	(150)	5795	(230)	5475	(215)
	1425	3.17	4385	(175)	6825	(270)	6420	(250)
	1550	3.45	5010	(195)	8025	(315)	7840	(310)
800	1175	1.80	3300	(130)	4895	(190)	4540	(180)
	1300	2.00	3820	(150)	5795	(230)	5475	(215)
	1425	2.18	4385	(175)	6825	(270)	6420	(250)
	1550	2.37	5010	(195)	8025	(315)	7840	(310)
	1675	2.56	5705	(225)	9435	(370)	9200	(360)
	1800	2.76	6475	(255)	11120	(440)	10815	(425)

[a] Clearances shown are based on specific gap factors. See Table 4 and Table 7 for other choices.
[b] Lightning impulse conditions may govern when low BSL levels are used. See Table 3.
[c] Values for maximum system voltages are from Table 2 of IEEE Std 1313.1-1996.
[d] See relevant apparatus standards for specific equipment clearance values.
[e] Assumptions for phase-to-ground clearances: altitude = sea level, coefficient of variation = 0.07.
[f] Assumptions for phase-to-phase clearances: altitude = sea level, coefficient of variation = 0.035. $BSL_{ph\text{-}ph}/BSL_{ph\text{-}g}$ = 1.56 to 1.74.
[g] Phase-to-phase clearances shown in Table 5 are metal-to-metal clearances not bus-to-bus centerlines.
[h] Additional considerations for safety clearances must be evaluated separately (see Clause 7).

[i] Equivalent SSF = BSL ÷ $V_{crest\ ph\text{-}g}$, where $V_{crest\ ph\text{-}g} = \sqrt{2}V_m / \sqrt{3}$.

<u>650 kV BIL Ex:</u>	SG-6	IEEE 1427
Min Ph-Gnd	50”	49”
Rec. Ph-Gnd	52.5”	N/A
Min Ph-Ph	63”	54”

BIL/Voltage Ratio

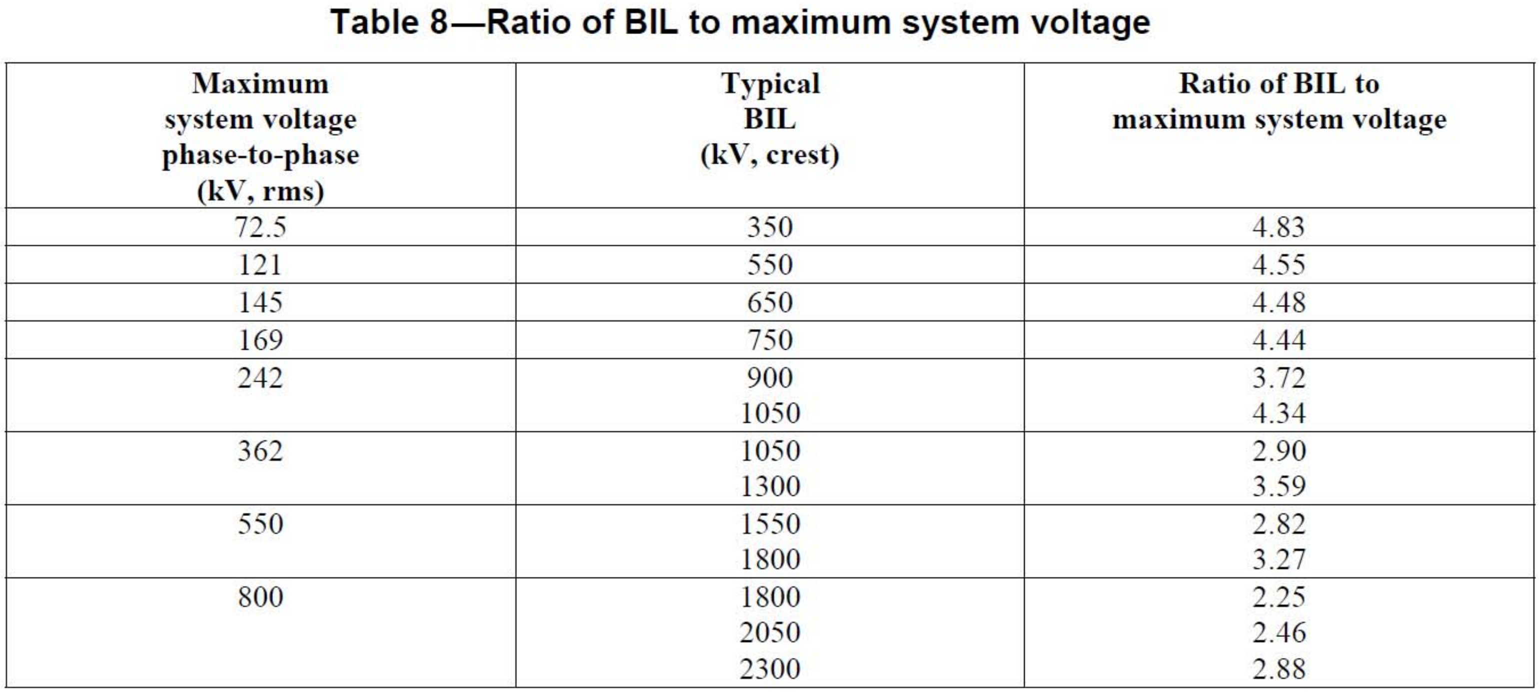


Table 8—Ratio of BIL to maximum system voltage

Maximum system voltage phase-to-phase (kV, rms)	Typical BIL (kV, crest)	Ratio of BIL to maximum system voltage
72.5	350	4.83
121	550	4.55
145	650	4.48
169	750	4.44
242	900 1050	3.72 4.34
362	1050 1300	2.90 3.59
550	1550 1800	2.82 3.27
800	1800 2050 2300	2.25 2.46 2.88

Table 8 shows the comparison between various maximum system voltages and BILs associated with these voltages. The comparison is intended ***ONLY*** to illustrate the ratio has decreased with use of higher system voltages.

Spacing & Clearances

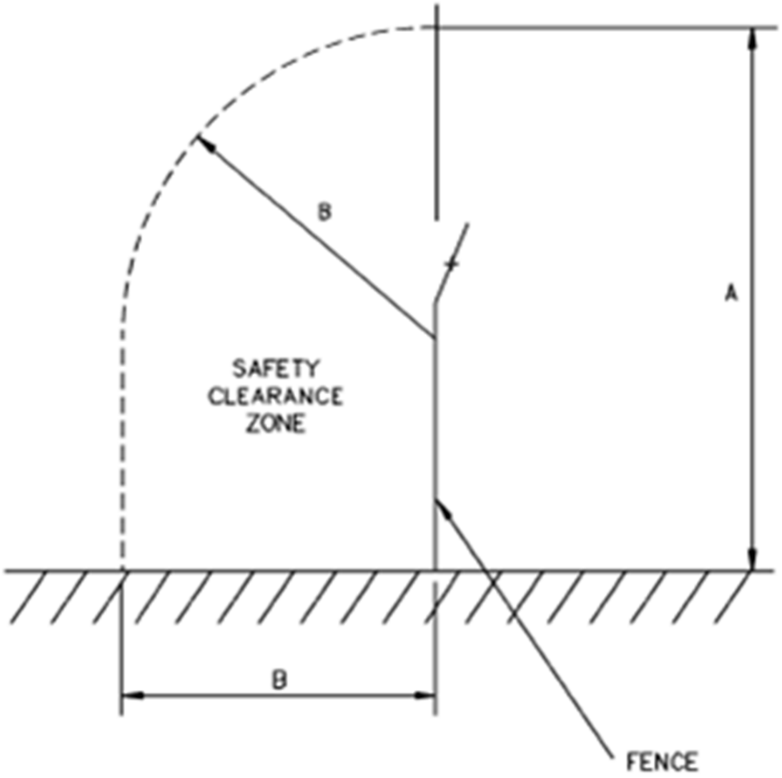
- IEEE 1427-2006 – What It Doesn’t Address
    - Uprating (Discussion Only)
    - Wildlife Conservation
    - Shielding Effects
    - Contamination
    - Hardware & Corona
    - Arcing During Switch Operation
    - Mechanical Stress Due to Fault Currents
    - Safety

Spacing & Clearances

- NESC (ANSI/IEEE C2)
  - Safety Based
  - Standard Installation and Maintenance Requirements
    - Stations
    - Aerial Lines
    - Underground Circuits
  - Grounding Methods
- NFPA 70E
  - Safe Working Clearances for Low and Medium-Voltage Equipment

Spacing & Clearances

- NESC Fence Safety Clearance



Spacing & Clearances

IEEE C37.32

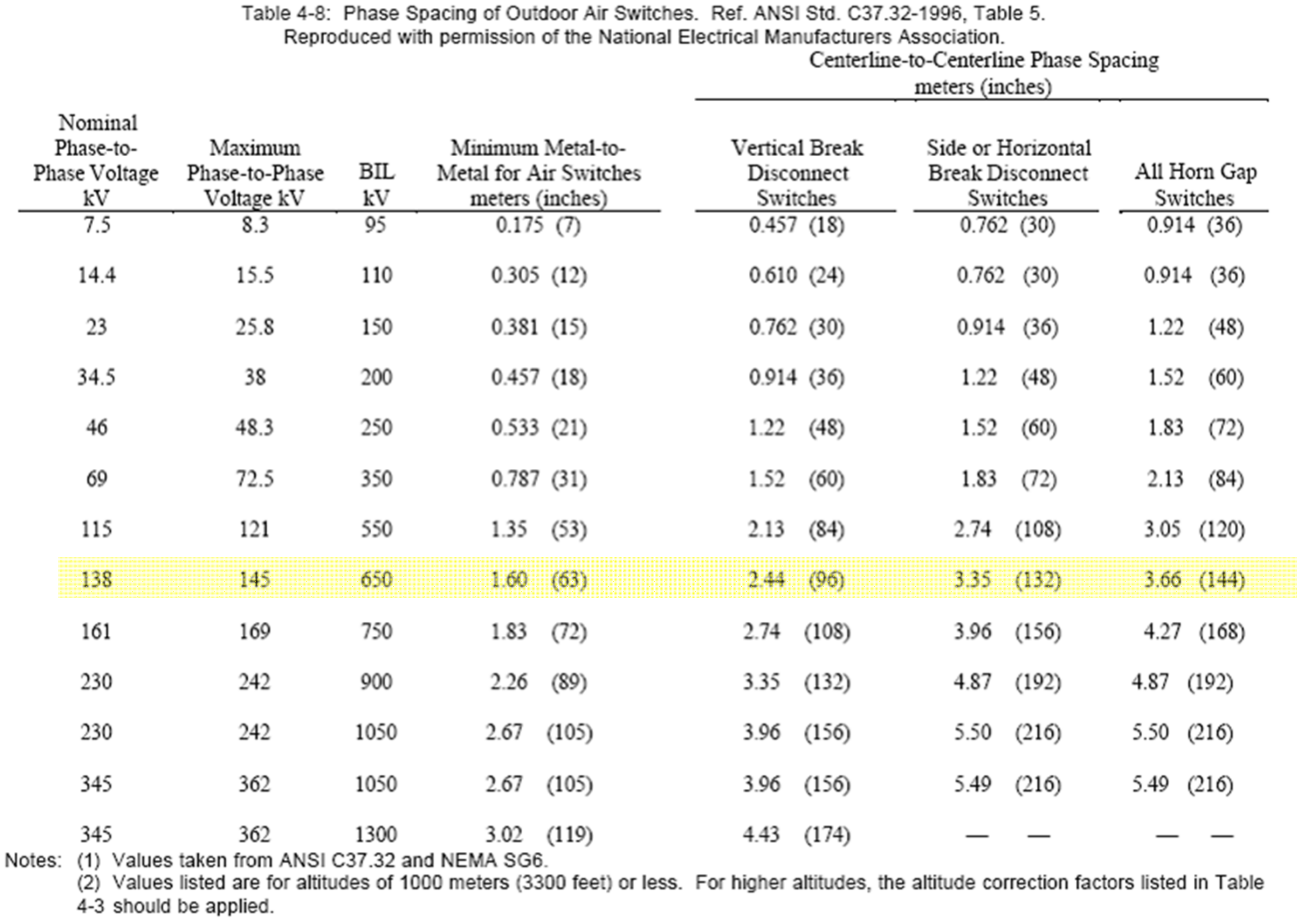
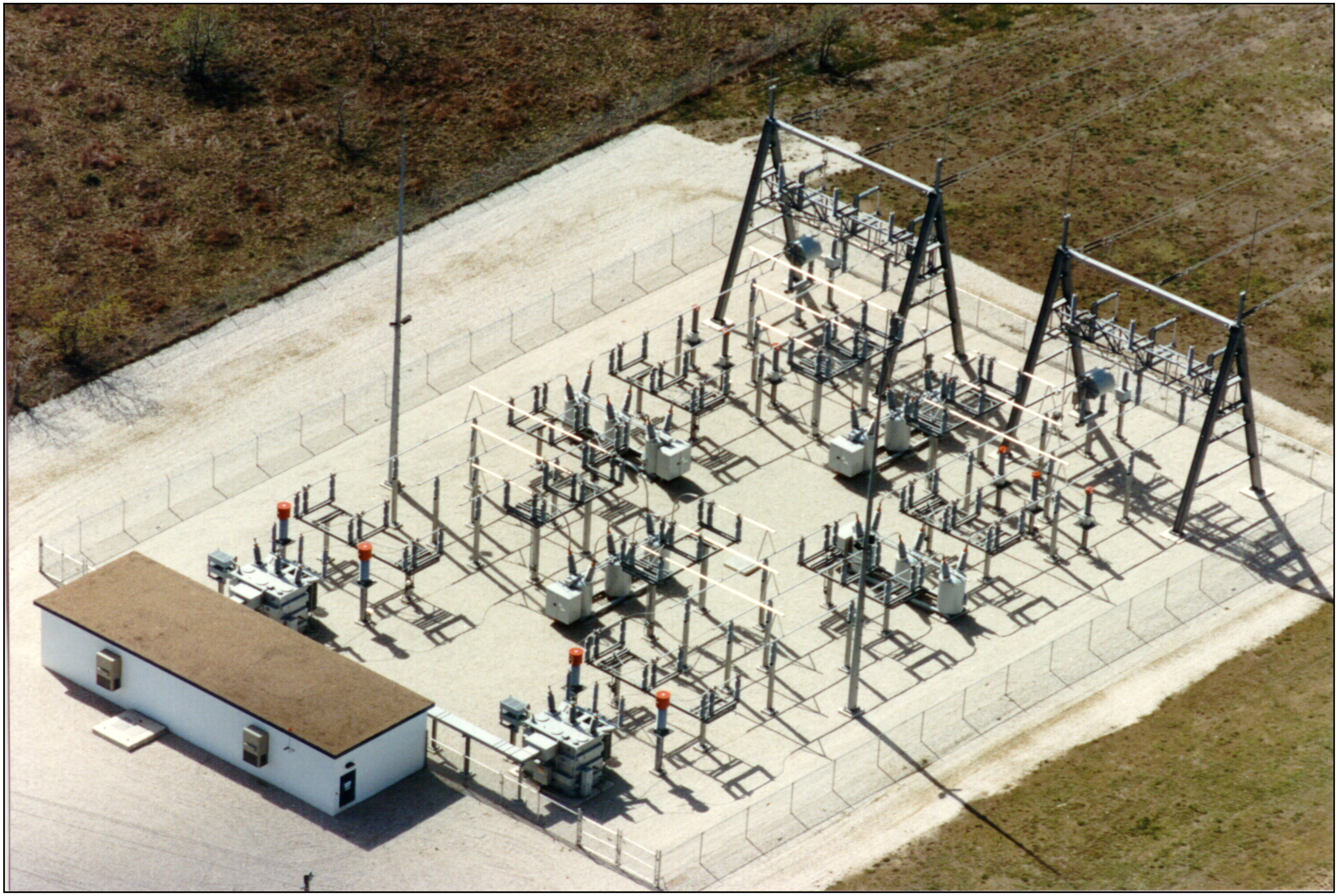


Table 4-8: Phase Spacing of Outdoor Air Switches. Ref. ANSI Std. C37.32-1996, Table 5.
Reproduced with permission of the National Electrical Manufacturers Association.

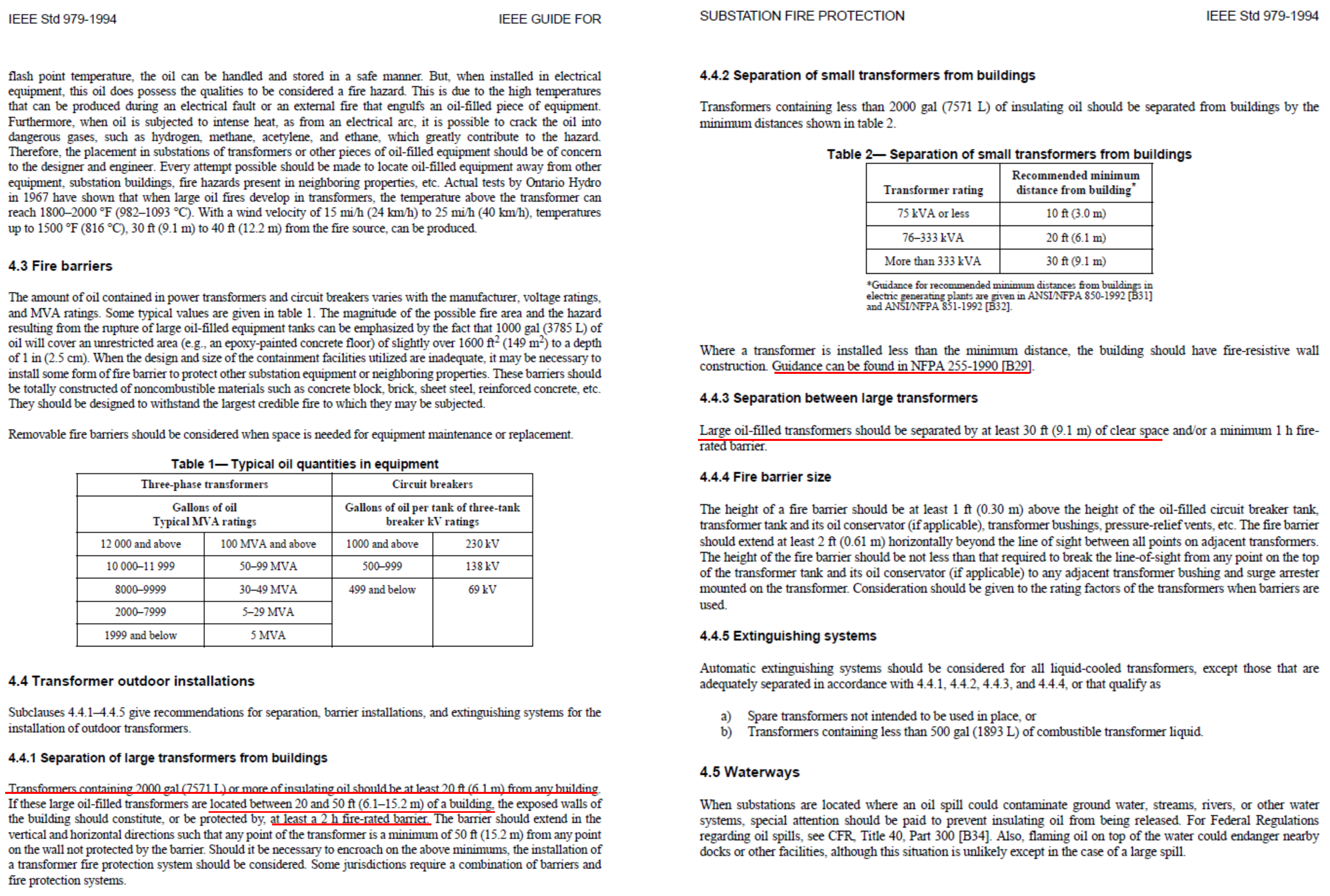
Nominal Phase-to-Phase Voltage kV	Maximum Phase-to-Phase Voltage kV	BIL kV	Minimum Metal-to-Metal for Air Switches meters (inches)	Centerline-to-Centerline Phase Spacing meters (inches) Vertical Break Disconnect Switches	Side or Horizontal Break Disconnect Switches	All Horn Gap Switches
7.5	8.3	95	0.175 (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.

Spacing & Clearances



Typical 138 kV Substation – Four (4) Breaker Ring Bus w/ Oil Circuit Breakers



IEEE Std 979-1994 IEEE GUIDE FOR

flash point temperature, the oil can be handled and stored in a safe manner. But, when installed in electrical equipment, this oil does possess the qualities to be considered a fire hazard. This is due to the high temperatures that can be produced during an electrical fault or an external fire that engulfs an oil-filled piece of equipment. Furthermore, when oil is subjected to intense heat, as from an electrical arc, it is possible to crack the oil into dangerous gases, such as hydrogen, methane, acetylene, and ethane, which greatly contribute to the hazard. Therefore, the placement in substations of transformers or other pieces of oil-filled equipment should be of concern to the designer and engineer. Every attempt possible should be made to locate oil-filled equipment away from other equipment, substation buildings, fire hazards present in neighboring properties, etc. Actual tests by Ontario Hydro in 1967 have shown that when large oil fires develop in transformers, the temperature above the transformer can reach 1800–2000 °F (982–1093 °C). With a wind velocity of 15 mi/h (24 km/h) to 25 mi/h (40 km/h), temperatures up to 1500 °F (816 °C), 30 ft (9.1 m) to 40 ft (12.2 m) from the fire source, can be produced.

4.3 Fire barriers

The amount of oil contained in power transformers and circuit breakers varies with the manufacturer, voltage ratings, and MVA ratings. Some typical values are given in table 1. The magnitude of the possible fire area and the hazard resulting from the rupture of large oil-filled equipment tanks can be emphasized by the fact that 1000 gal (3785 L) of oil will cover an unrestricted area (e.g., an epoxy-painted concrete floor) of slightly over 1600 ft^2 (149 m^2) to a depth of 1 in (2.5 cm). When the design and size of the containment facilities utilized are inadequate, it may be necessary to install some form of fire barrier to protect other substation equipment or neighboring properties. These barriers should be totally constructed of noncombustible materials such as concrete block, brick, sheet steel, reinforced concrete, etc. They should be designed to withstand the largest credible fire to which they may be subjected.

Removable fire barriers should be considered when space is needed for equipment maintenance or replacement.

Table 1— Typical oil quantities in equipment

Three-phase transformers		Circuit breakers	
Gallons of oil	Typical MVA ratings	Gallons of oil per tank of three-tank	breaker kV ratings
12 000 and above	100 MVA and above	1000 and above	230 kV
10 000–11 999	50–99 MVA	500–999	138 kV
8000–9999	30–49 MVA	499 and below	69 kV
2000–7999	5–29 MVA		
1999 and below	5 MVA		

4.4 Transformer outdoor installations

Subclauses 4.4.1–4.4.5 give recommendations for separation, barrier installations, and extinguishing systems for the installation of outdoor transformers.

4.4.1 Separation of large transformers from buildings

Transformers containing 2000 gal (7571 L) or more of insulating oil should be at least 20 ft (6.1 m) from any building. If these large oil-filled transformers are located between 20 and 50 ft (6.1–15.2 m) of a building, the exposed walls of the building should constitute, or be protected by, at least a 2 h fire-rated barrier. The barrier should extend in the vertical and horizontal directions such that any point of the transformer is a minimum of 50 ft (15.2 m) from any point on the wall not protected by the barrier. Should it be necessary to encroach on the above minimums, the installation of a transformer fire protection system should be considered. Some jurisdictions require a combination of barriers and fire protection systems.

SUBSTATION FIRE PROTECTION IEEE Std 979-1994

4.4.2 Separation of small transformers from buildings

Transformers containing less than 2000 gal (7571 L) of insulating oil should be separated from buildings by the minimum distances shown in table 2.

Table 2— Separation of small transformers from buildings

Transformer rating	Recommended minimum distance from building*
75 kVA or less	10 ft (3.0 m)
76–333 kVA	20 ft (6.1 m)
More than 333 kVA	30 ft (9.1 m)

*Guidance for recommended minimum distances from buildings in electric generating plants are given in ANSI/NFPA 850-1992 [B31] and ANSI/NFPA 851-1992 [B32].

Where a transformer is installed less than the minimum distance, the building should have fire-resistive wall construction. Guidance can be found in NFPA 255-1990 [B29].

4.4.3 Separation between large transformers

Large oil-filled transformers should be separated by at least 30 ft (9.1 m) of clear space and/or a minimum 1 h fire-rated barrier.

4.4.4 Fire barrier size

The height of a fire barrier should be at least 1 ft (0.30 m) above the height of the oil-filled circuit breaker tank, transformer tank and its oil conservator (if applicable), transformer bushings, pressure-relief vents, etc. The fire barrier should extend at least 2 ft (0.61 m) horizontally beyond the line of sight between all points on adjacent transformers. The height of the fire barrier should be not less than that required to break the line-of-sight from any point on the top of the transformer tank and its oil conservator (if applicable) to any adjacent transformer bushing and surge arrester mounted on the transformer. Consideration should be given to the rating factors of the transformers when barriers are used.

4.4.5 Extinguishing systems

Automatic extinguishing systems should be considered for all liquid-cooled transformers, except those that are adequately separated in accordance with 4.4.1, 4.4.2, 4.4.3, and 4.4.4, or that qualify as

a) Spare transformers not intended to be used in place, or
b) Transformers containing less than 500 gal (1893 L) of combustible transformer liquid.

4.5 Waterways

When substations are located where an oil spill could contaminate ground water, streams, rivers, or other water systems, special attention should be paid to prevent insulating oil from being released. For Federal Regulations regarding oil spills, see CFR, Title 40, Part 300 [B34]. Also, flaming oil on top of the water could endanger nearby docks or other facilities, although this situation is unlikely except in the case of a large spill.

Spacing & Clearances

Dielectric Fluids

COOPER Power Systems

NEC® Requirement Guidelines 2011 Code Options for the Installation of Listed Less-Flammable Liquid-Filled Transformers

Reference Information

R900-20-13

Less-flammable liquids for transformers: fire point > 300 deg C

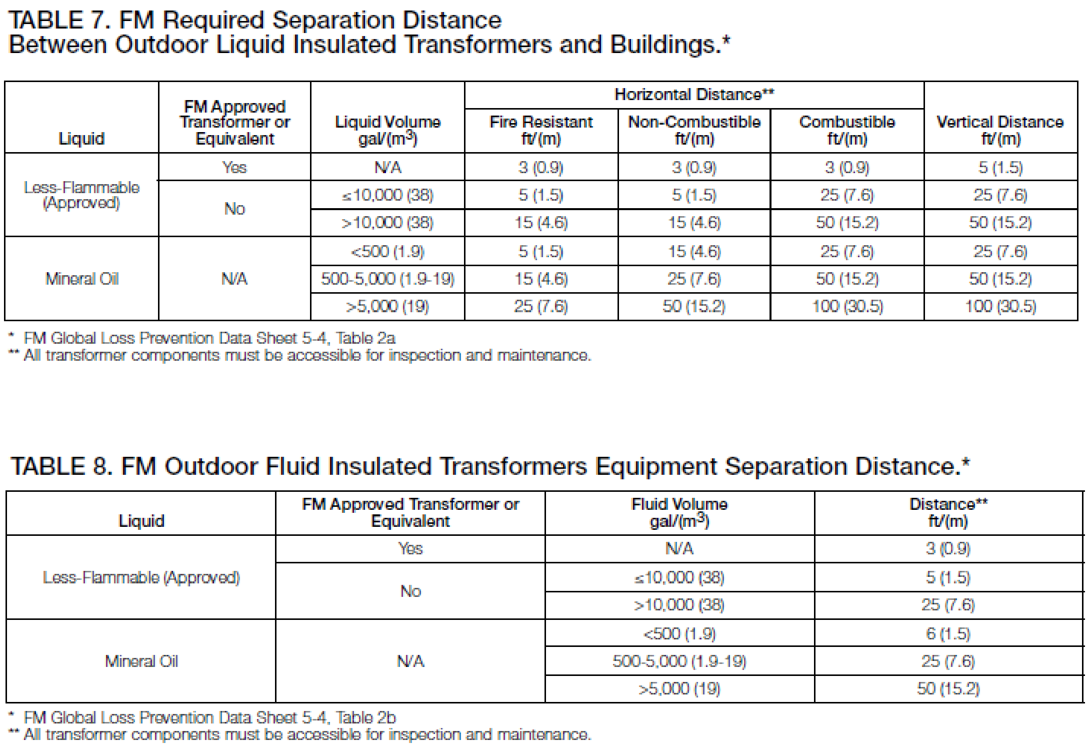


TABLE 7. FM Required Separation Distance
Between Outdoor Liquid Insulated Transformers and Buildings.*

Liquid	FM Approved Transformer or Equivalent	Liquid Volume gal/(m^3)	Horizontal Distance** Fire Resistant ft/(m)	Horizontal Distance** Non-Combustible ft/(m)	Horizontal Distance** Combustible ft/(m)	Vertical Distance ft/(m)
Less-Flammable (Approved)	Yes	N/A	3 (0.9)	3 (0.9)	3 (0.9)	5 (1.5)
	No	≤10,000 (38)	5 (1.5)	5 (1.5)	25 (7.6)	25 (7.6)
		>10,000 (38)	15 (4.6)	15 (4.6)	50 (15.2)	50 (15.2)
Mineral Oil	N/A	<500 (1.9)	5 (1.5)	15 (4.6)	25 (7.6)	25 (7.6)
		500-5,000 (1.9-19)	15 (4.6)	25 (7.6)	50 (15.2)	50 (15.2)
		>5,000 (19)	25 (7.6)	50 (15.2)	100 (30.5)	100 (30.5)

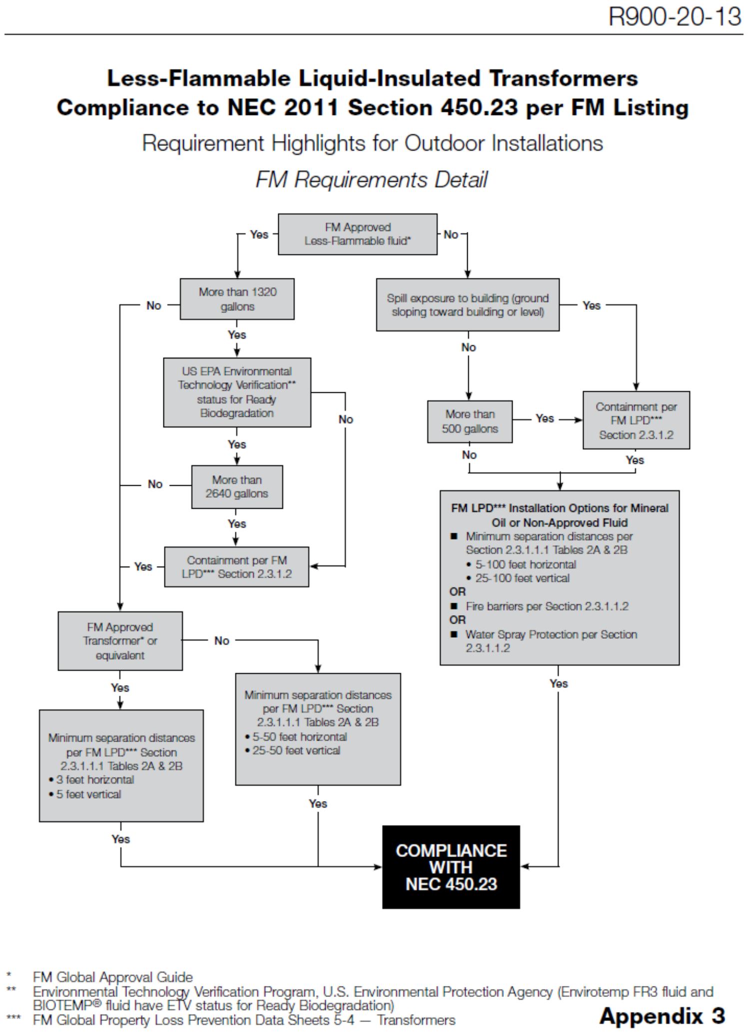
* FM Global Loss Prevention Data Sheet 5-4, Table 2a
** All transformer components must be accessible for inspection and maintenance.

TABLE 8. FM Outdoor Fluid Insulated Transformers Equipment Separation Distance.*

Liquid	FM Approved Transformer or Equivalent	Fluid Volume gal/(m^3)	Distance** ft/(m)
Less-Flammable (Approved)	Yes	N/A	3 (0.9)
	No	≤10,000 (38)	5 (1.5)
		>10,000 (38)	25 (7.6)
Mineral Oil	N/A	<500 (1.9)	6 (1.5)
		500-5,000 (1.9-19)	25 (7.6)
		>5,000 (19)	50 (15.2)

* FM Global Loss Prevention Data Sheet 5-4, Table 2b
** All transformer components must be accessible for inspection and maintenance.

Spacing & Clearances



R900-20-13

Less-Flammable Liquid-Insulated Transformers Compliance to NEC 2011 Section 450.23 per FM Listing

Requirement Highlights for Outdoor Installations

FM Requirements Detail

FM Approved Less-Flammable fluid*

More than 1320 gallons

US EPA Environmental Technology Verification** status for Ready Biodegradation

More than 2640 gallons

Containment per FM LPD*** Section 2.3.1.2

FM Approved Transformer* or equivalent

Minimum separation distances per FM LPD*** Section 2.3.1.1.1 Tables 2A & 2B
- 3 feet horizontal
- 5 feet vertical

Minimum separation distances per FM LPD*** Section 2.3.1.1.1 Tables 2A & 2B
- 5-50 feet horizontal
- 25-50 feet vertical

Spill exposure to building (ground sloping toward building or level)

More than 500 gallons

Containment per FM LPD*** Section 2.3.1.2

FM LPD* Installation Options for Mineral Oil or Non-Approved Fluid**
- ■ Minimum separation distances per Section 2.3.1.1.1 Tables 2A & 2B
  - 5-100 feet horizontal
  - 25-100 feet vertical

OR
- ■ Fire barriers per Section 2.3.1.1.2

OR
- ■ Water Spray Protection per Section 2.3.1.1.2

COMPLIANCE WITH NEC 450.23

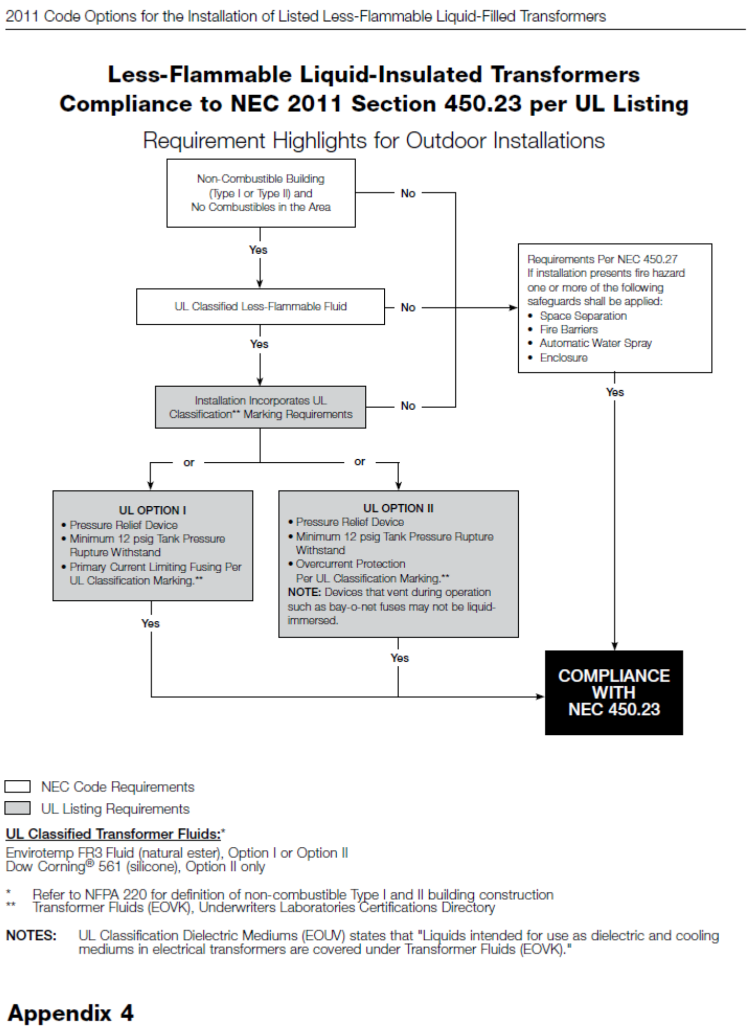
---

* FM Global Approval Guide

** Environmental Technology Verification Program, U.S. Environmental Protection Agency (Envirotemp FR3 fluid and BIOTEMP® fluid have ETV status for Ready Biodegradation)

*** FM Global Property Loss Prevention Data Sheets 5-4 — Transformers

Appendix 3



2011 Code Options for the Installation of Listed Less-Flammable Liquid-Filled Transformers

Less-Flammable Liquid-Insulated Transformers Compliance to NEC 2011 Section 450.23 per UL Listing

Requirement Highlights for Outdoor Installations

Non-Combustible Building (Type I or Type II) and No Combustibles in the Area

UL Classified Less-Flammable Fluid

Installation Incorporates UL Classification** Marking Requirements

UL OPTION I
- Pressure Relief Device
- Minimum 12 psig Tank Pressure Rupture Withstand
- Primary Current Limiting Fusing Per UL Classification Marking.**

UL OPTION II
- Pressure Relief Device
- Minimum 12 psig Tank Pressure Rupture Withstand
- Overcurrent Protection Per UL Classification Marking.**

NOTE: Devices that vent during operation such as bay-o-net fuses may not be liquid-immersed.

Requirements Per NEC 450.27
If installation presents fire hazard one or more of the following safeguards shall be applied:
- Space Separation
- Fire Barriers
- Automatic Water Spray
- Enclosure

COMPLIANCE WITH NEC 450.23

☐ NEC Code Requirements

▨ UL Listing Requirements

UL Classified Transformer Fluids:*

Envirotemp FR3 Fluid (natural ester), Option I or Option II
Dow Corning® 561 (silicone), Option II only

* Refer to NFPA 220 for definition of non-combustible Type I and II building construction

** Transformer Fluids (EOVK), Underwriters Laboratories Certifications Directory

NOTES: UL Classification Dielectric Mediums (EOUV) states that "Liquids intended for use as dielectric and cooling mediums in electrical transformers are covered under Transformer Fluids (EOVK)."

Appendix 4

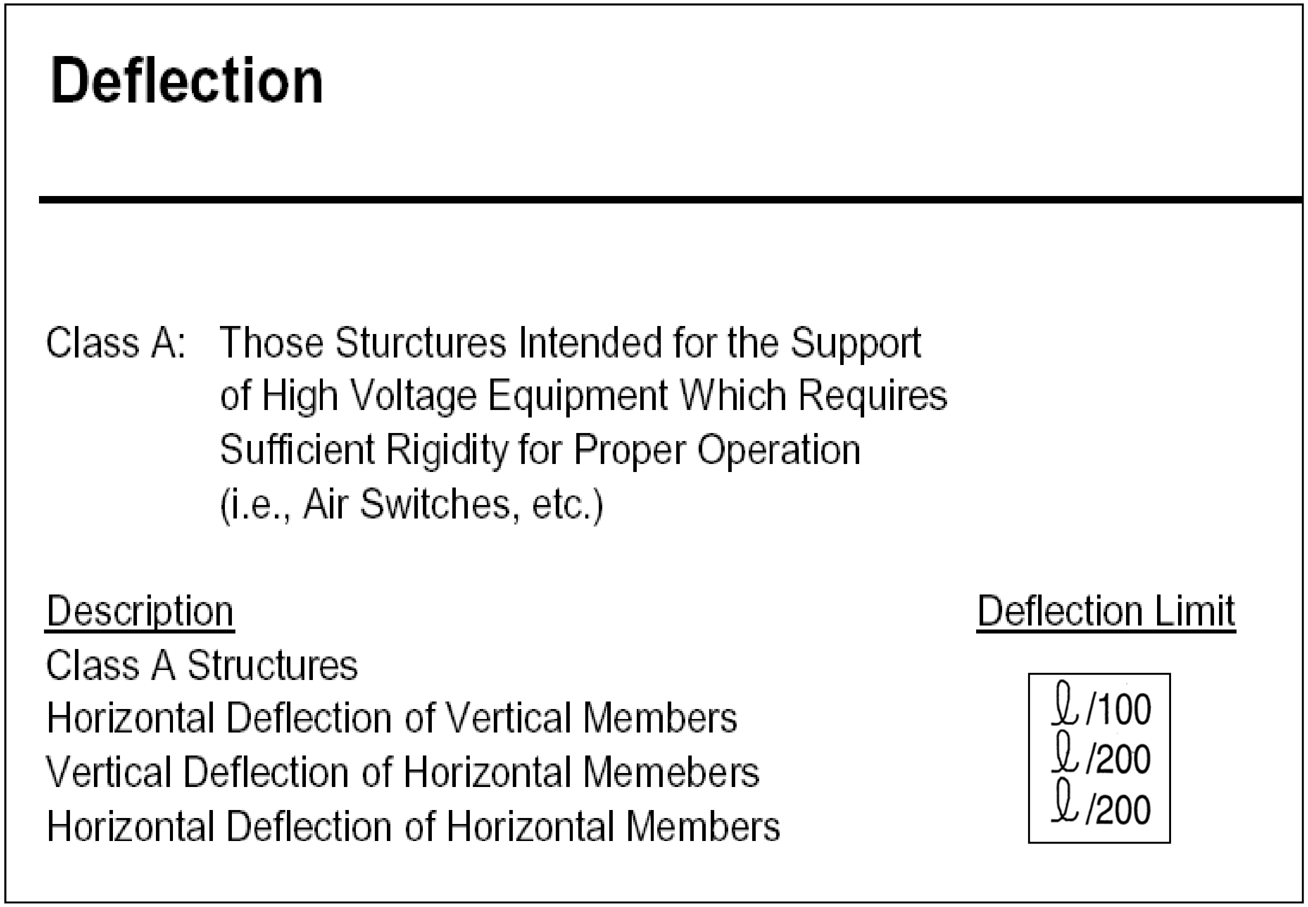
Spacing & Clearances

Spacing Affects Structural Design

Spacing & Clearances

- Applied Forces
    - Wind
    - Ice
    - Forces from Short-Circuit Faults ←
- Design Considerations
    - Insulator strength to withstand forces from short-circuit faults
    - Structural steel strength under short-circuit fault forces (moments)
    - Foundation design under high moments
    - Ice loading, bus bar strength, and bus spans
    - Thermal expansion and use of expansion joints
- IEEE 605 – IEEE Guide for Design of Substation Rigid-Bus Structures

Structural Requirements

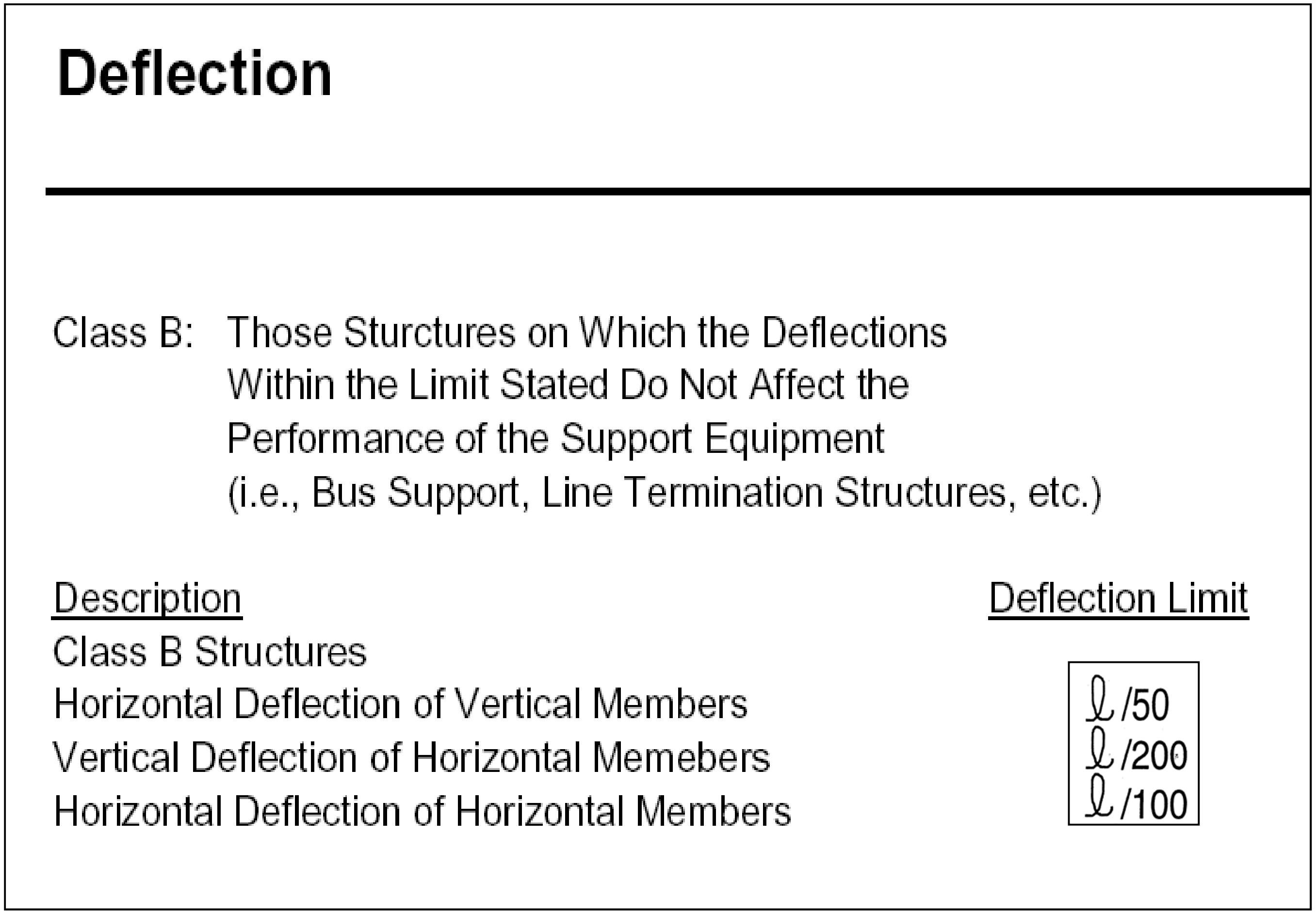


Deflection

Class A: Those Sturctures Intended for the Support of High Voltage Equipment Which Requires Sufficient Rigidity for Proper Operation (i.e., Air Switches, etc.)

Description	Deflection Limit
Class A Structures	
Horizontal Deflection of Vertical Members	$\ell/100$
Vertical Deflection of Horizontal Memebers	$\ell/200$
Horizontal Deflection of Horizontal Members	$\ell/200$

Structural Design



Deflection

Class B: Those Sturctures on Which the Deflections Within the Limit Stated Do Not Affect the Performance of the Support Equipment (i.e., Bus Support, Line Termination Structures, etc.)

Description	Deflection Limit
Class B Structures	
Horizontal Deflection of Vertical Members	$\ell/50$
Vertical Deflection of Horizontal Memebers	$\ell/200$
Horizontal Deflection of Horizontal Members	$\ell/100$

Structural Design

- Bus Supports
  - Short-Circuit Forces
  - Wind Loading
  - Ice Loading
  - Seismic Forces

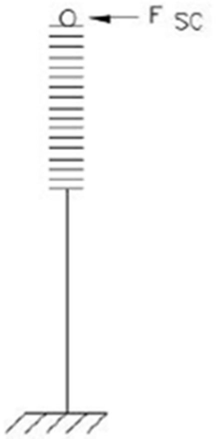
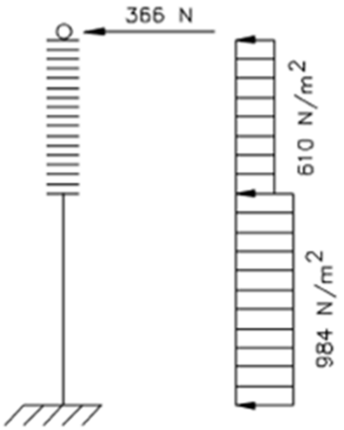


Figure 7-2: Tubular Structure—Short-Circuit Loading



Structural Design

Short-Circuit Forces

$$F(t)=\frac{\mu}{4\pi r^2} i_1(t) i_2(t) \left[d_1 \otimes (u_r \otimes d_2) \right]$$

where

μ	is the magnetic permeability equal to $4\pi \times 10^{-7}$ V-s/(A-m)
r	is the distance between the two conductor segments
u_r	is the unit directional vector in the direction r
d_1	is a vector of length d_1 in the direction of the current flow in conductor segment 1
d_2	is a vector of length d_2 in the direction of the current flow in conductor segment 2

NOTE—The symbol ⊗ is the vectorial cross product.

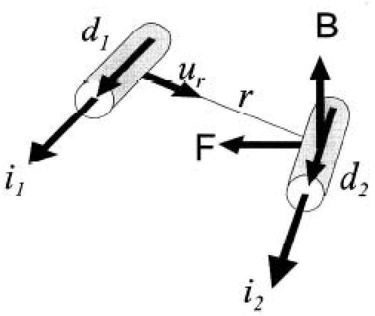
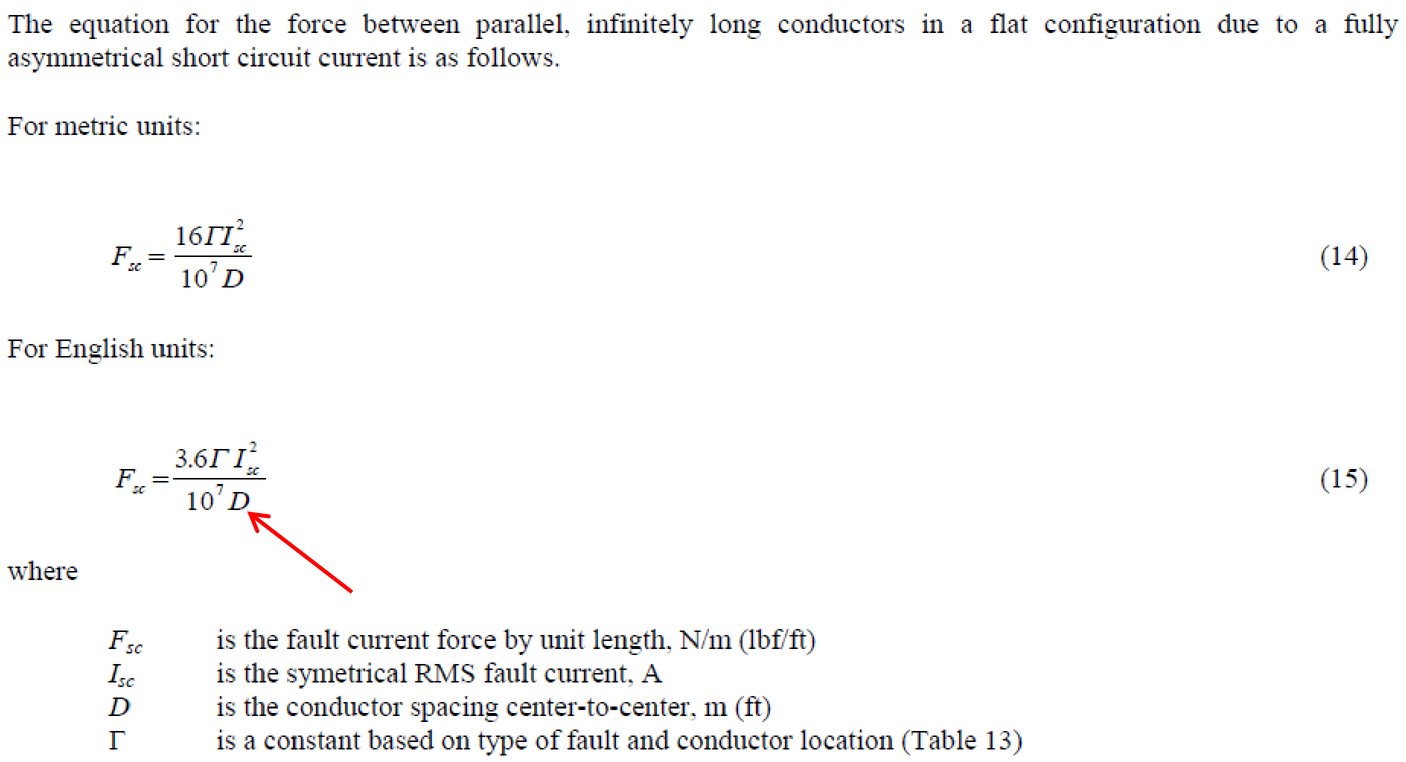


Figure 19 —Illustration of two conductor segments carrying electric current

Structural Design

Short-Circuit Forces



The equation for the force between parallel, infinitely long conductors in a flat configuration due to a fully asymmetrical short circuit current is as follows.

For metric units:

$$F_{sc} = \frac{16\Gamma I_{sc}^2}{10^7 D} \qquad (14)$$

For English units:

$$F_{sc} = \frac{3.6\Gamma\, I_{sc}^2}{10^7\, D} \qquad (15)$$

where

F_{sc}	is the fault current force by unit length, N/m (lbf/ft)
I_{sc}	is the symetrical RMS fault current, A
D	is the conductor spacing center-to-center, m (ft)
Γ	is a constant based on type of fault and conductor location (Table 13)

Structural Design

Short-Circuit Forces

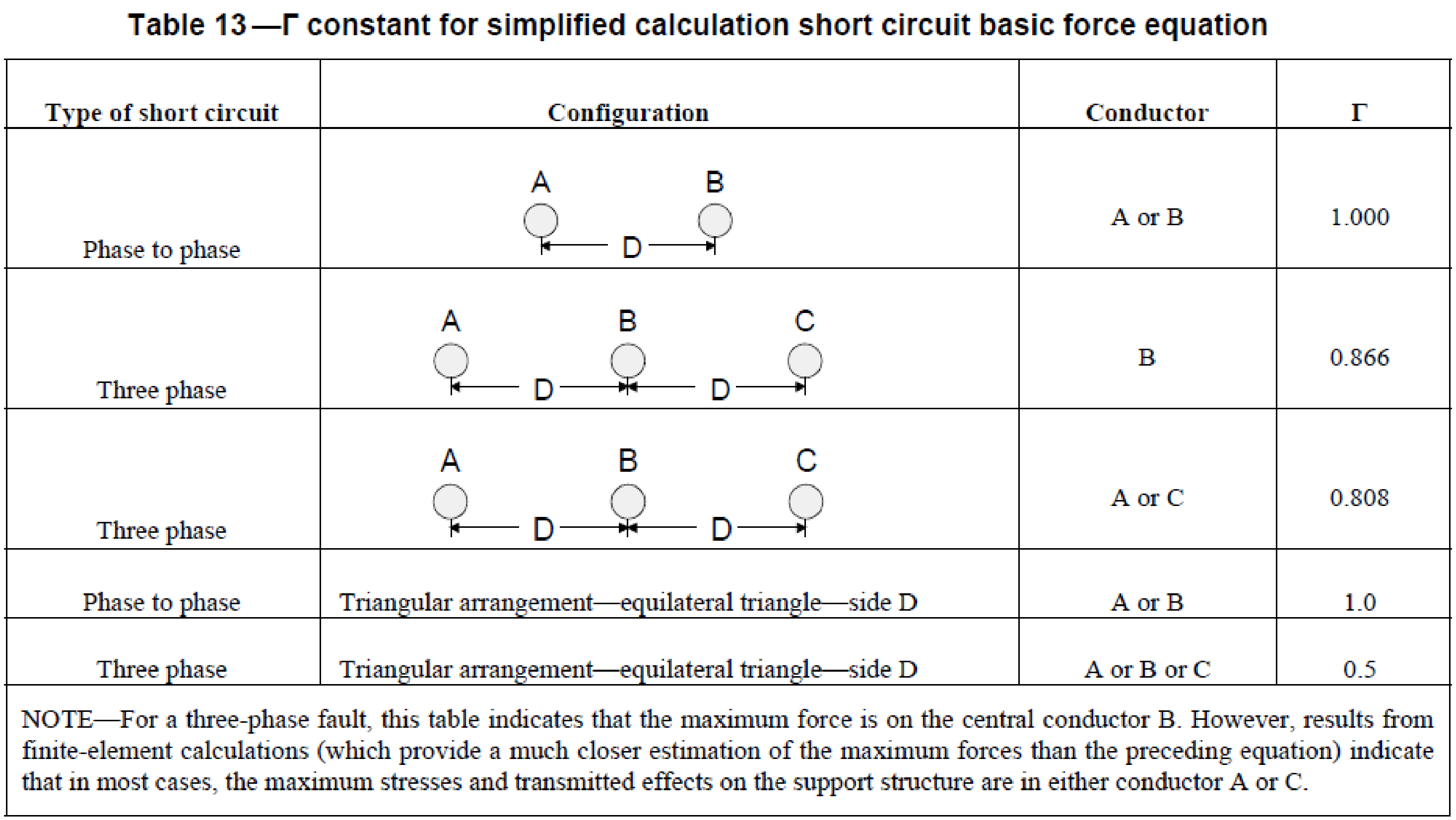


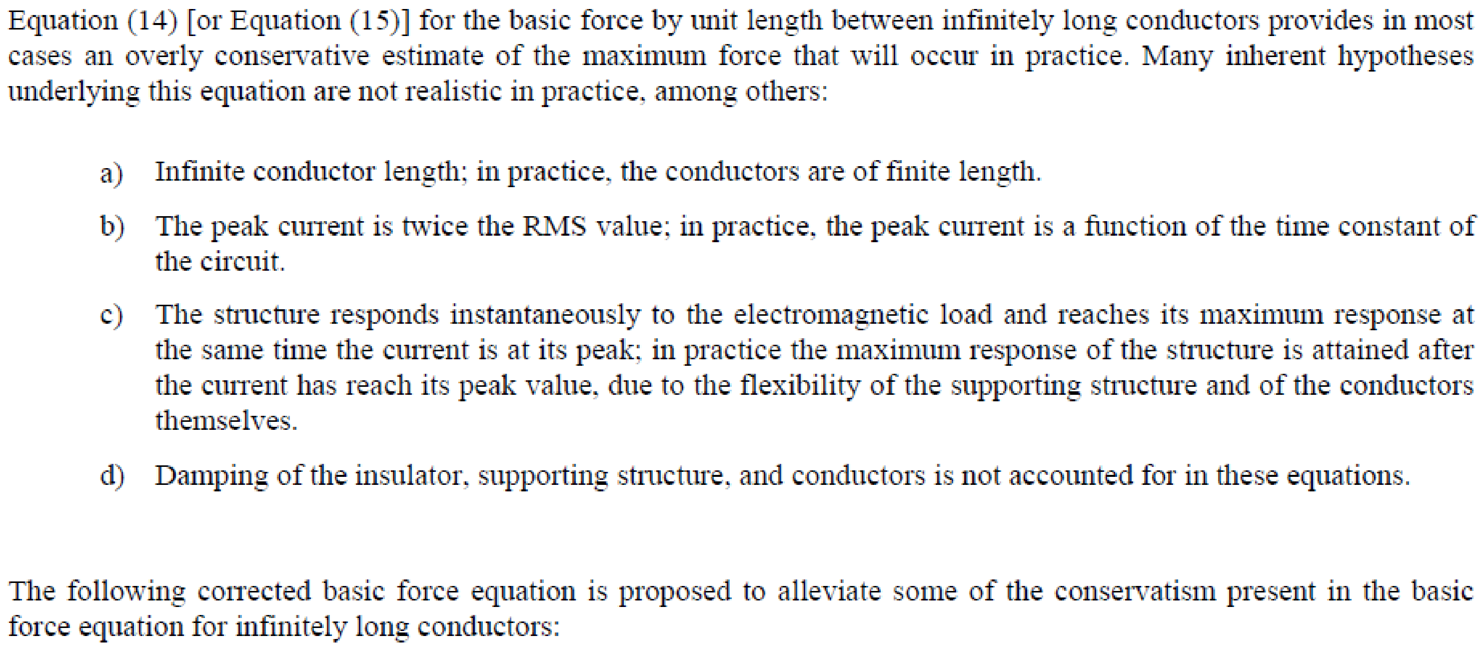
Table 13—Γ constant for simplified calculation short circuit basic force equation

Type of short circuit	Configuration	Conductor	Γ
Phase to phase		A or B	1.000
Three phase		B	0.866
Three phase		A or C	0.808
Phase to phase	Triangular arrangement—equilateral triangle—side D	A or B	1.0
Three phase	Triangular arrangement—equilateral triangle—side D	A or B or C	0.5

NOTE—For a three-phase fault, this table indicates that the maximum force is on the central conductor B. However, results from finite-element calculations (which provide a much closer estimation of the maximum forces than the preceding equation) indicate that in most cases, the maximum stresses and transmitted effects on the support structure are in either conductor A or C.

Structural Design

Short-Circuit Forces



Equation (14) [or Equation (15)] for the basic force by unit length between infinitely long conductors provides in most cases an overly conservative estimate of the maximum force that will occur in practice. Many inherent hypotheses underlying this equation are not realistic in practice, among others:

a) Infinite conductor length; in practice, the conductors are of finite length.

b) The peak current is twice the RMS value; in practice, the peak current is a function of the time constant of the circuit.

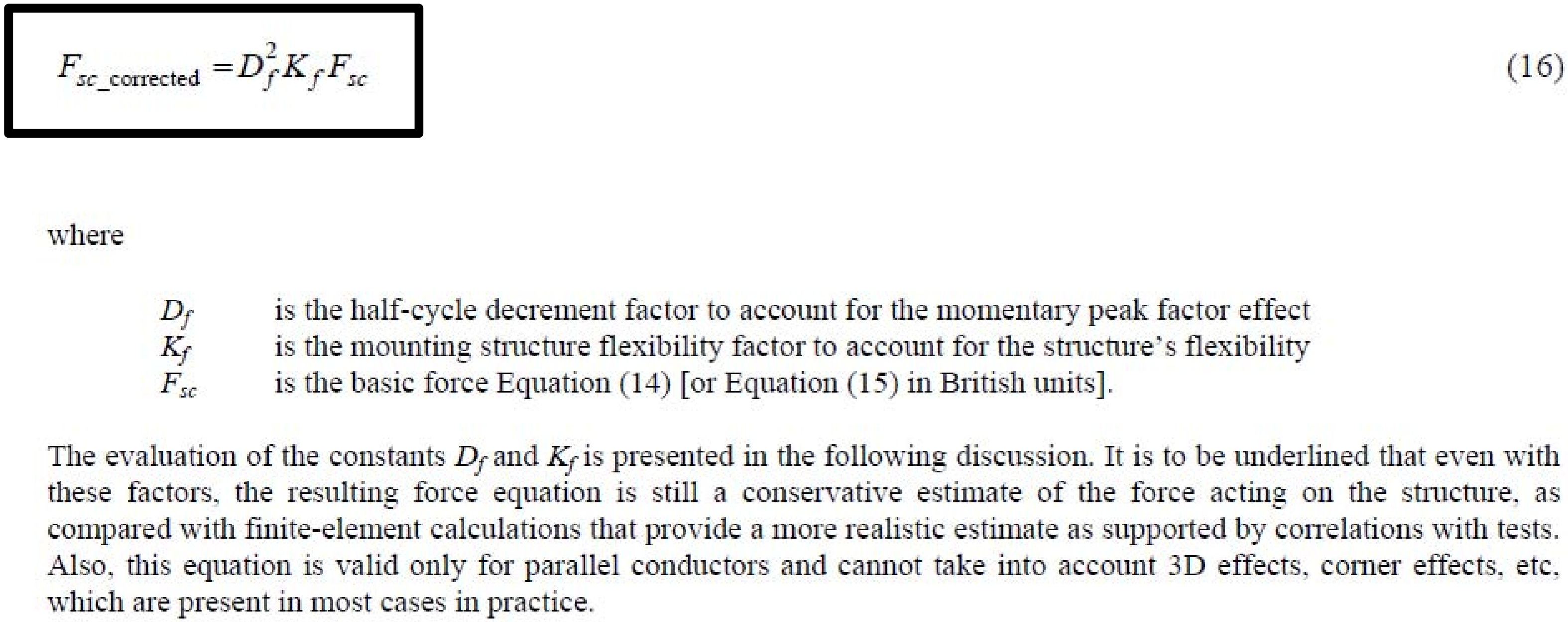
c) The structure responds instantaneously to the electromagnetic load and reaches its maximum response at the same time the current is at its peak; in practice the maximum response of the structure is attained after the current has reach its peak value, due to the flexibility of the supporting structure and of the conductors themselves.

d) Damping of the insulator, supporting structure, and conductors is not accounted for in these equations.

The following corrected basic force equation is proposed to alleviate some of the conservatism present in the basic force equation for infinitely long conductors:

Structural Design

Short-Circuit Forces



$$\boxed{F_{sc\_\mathrm{corrected}} = D_f^2 K_f F_{sc}} \qquad (16)$$

where

D_f	is the half-cycle decrement factor to account for the momentary peak factor effect
K_f	is the mounting structure flexibility factor to account for the structure's flexibility
F_{sc}	is the basic force Equation (14) [or Equation (15) in British units].

The evaluation of the constants D_f and K_f is presented in the following discussion. It is to be underlined that even with these factors, the resulting force equation is still a conservative estimate of the force acting on the structure, as compared with finite-element calculations that provide a more realistic estimate as supported by correlations with tests. Also, this equation is valid only for parallel conductors and cannot take into account 3D effects, corner effects, etc, which are present in most cases in practice.

Structural Design

Short-Circuit Forces

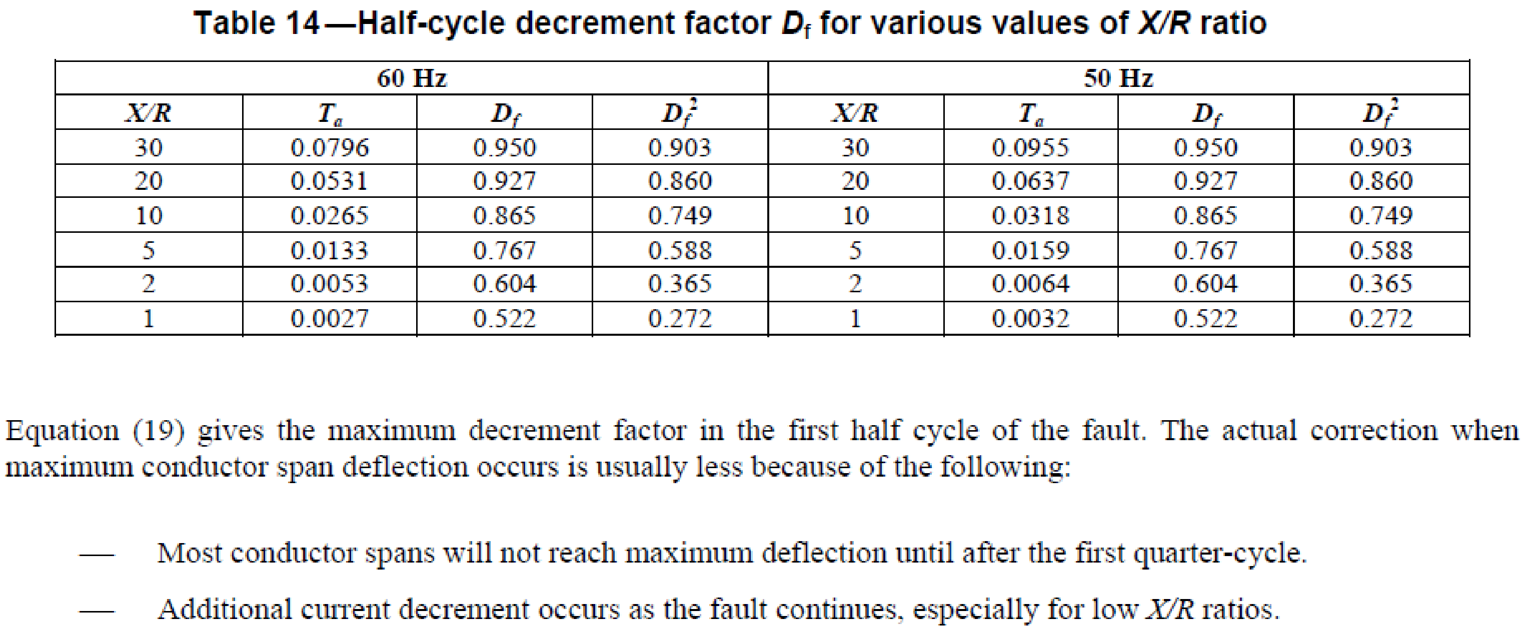


Table 14—Half-cycle decrement factor D_f for various values of X/R ratio

60 Hz				50 Hz			
X/R	T_a	D_f	D_f^2	X/R	T_a	D_f	D_f^2
30	0.0796	0.950	0.903	30	0.0955	0.950	0.903
20	0.0531	0.927	0.860	20	0.0637	0.927	0.860
10	0.0265	0.865	0.749	10	0.0318	0.865	0.749
5	0.0133	0.767	0.588	5	0.0159	0.767	0.588
2	0.0053	0.604	0.365	2	0.0064	0.604	0.365
1	0.0027	0.522	0.272	1	0.0032	0.522	0.272

Equation (19) gives the maximum decrement factor in the first half cycle of the fault. The actual correction when maximum conductor span deflection occurs is usually less because of the following:

- Most conductor spans will not reach maximum deflection until after the first quarter-cycle.
- Additional current decrement occurs as the fault continues, especially for low X/R ratios.

Structural Design

Short-Circuit Forces

Because of their flexibility, the bus and mounting structures are capable of absorbing energy during a fault. Thus, depending on the type of mounting structures and their heights, the effective fault current forces will be lower than the half-cycle maximum value. The effect of the structure flexibility is accounted with the mounting-structure flexibility factor, K_f.

Values of K_f for single-phase mounting structures are given in Figure 20. K_f is usually assumed to be unity for three-phase mounting structures.

NOTE—A, lattice and tubular aluminum; B, tubular and wide-flange steel and wood pole; C, lattice steel; D, solid concrete.

Structural Design

- Rated Continuous Current
- Selected Ambient Base
- Allowable Temperature Rise
- Equipment Limitations
- Interaction with Transmission Lines
- Other Factors
    - Wind
    - Ice Loading
    - Emissivity

Current Ratings

IEEE 605-2008 is a great resource:

- Conductor Physical Properties
- Conductor Electrical Properties
- Examples of Calculations

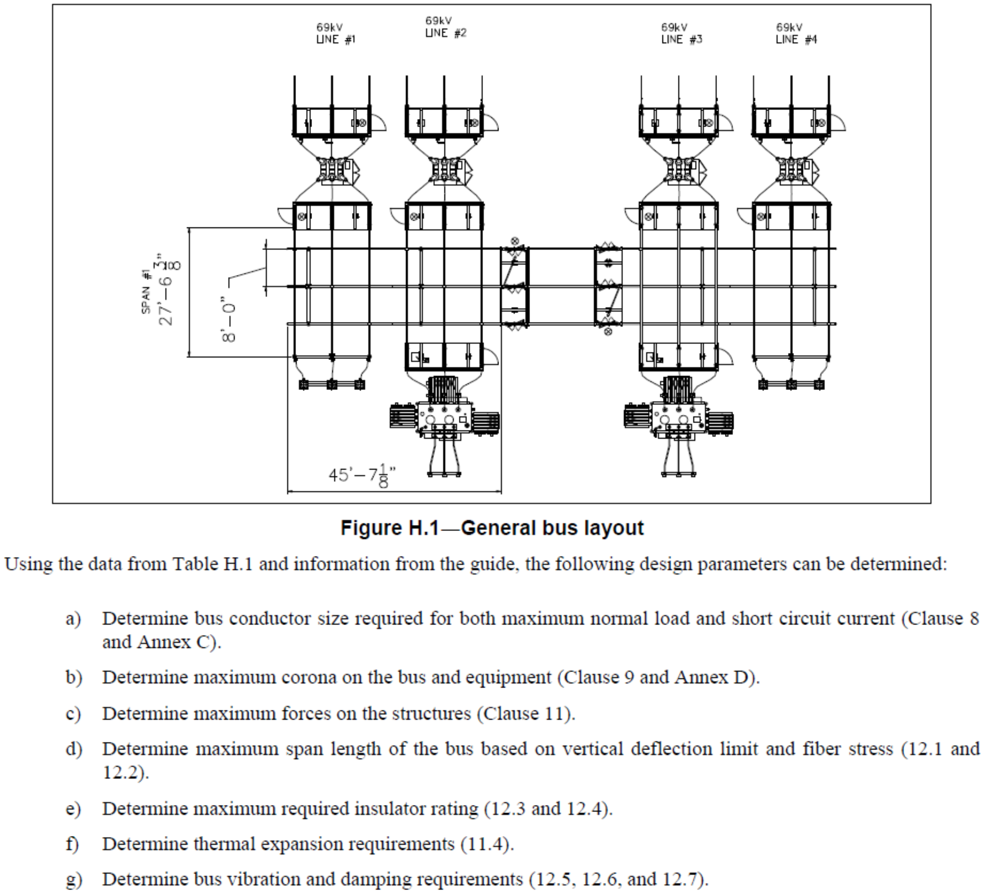


Figure H.1—General bus layout

Using the data from Table H.1 and information from the guide, the following design parameters can be determined:

a) Determine bus conductor size required for both maximum normal load and short circuit current (Clause 8 and Annex C).

b) Determine maximum corona on the bus and equipment (Clause 9 and Annex D).

c) Determine maximum forces on the structures (Clause 11).

d) Determine maximum span length of the bus based on vertical deflection limit and fiber stress (12.1 and 12.2).

e) Determine maximum required insulator rating (12.3 and 12.4).

f) Determine thermal expansion requirements (11.4).

g) Determine bus vibration and damping requirements (12.5, 12.6, and 12.7).

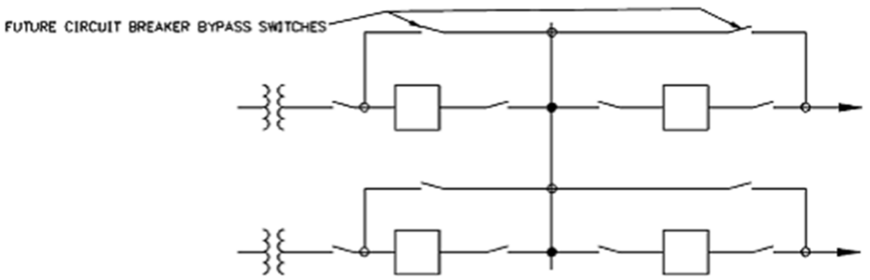
Bus Design

Types of Substation Structures

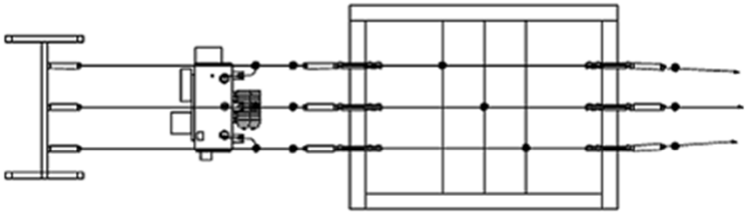
Station Physical Layout

- **Conventional** (Lattice Structures)
    - Angle (Chord & Lace) Members
    - Minimum Structure Weight
    - Requires Minimum Site Area
    - Stable and Rigid Construction
    - Requires Considerable Bolting & Erection Time

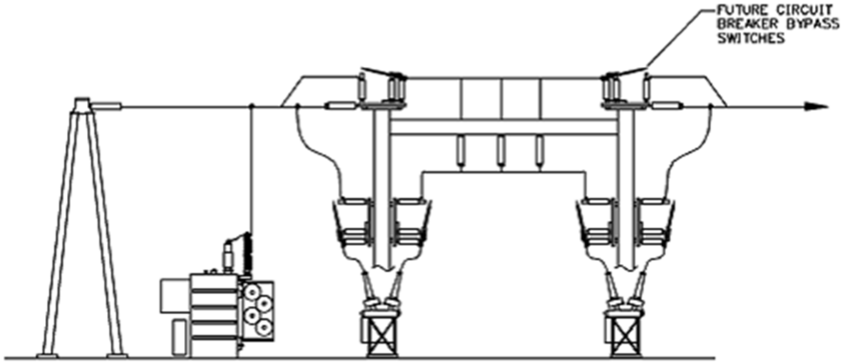
Station Physical Layout



TYPICAL ONE-LINE DIAGRAM



PLAN VIEW–TYPICAL BAY



ELEVATON–TYPICAL BAY

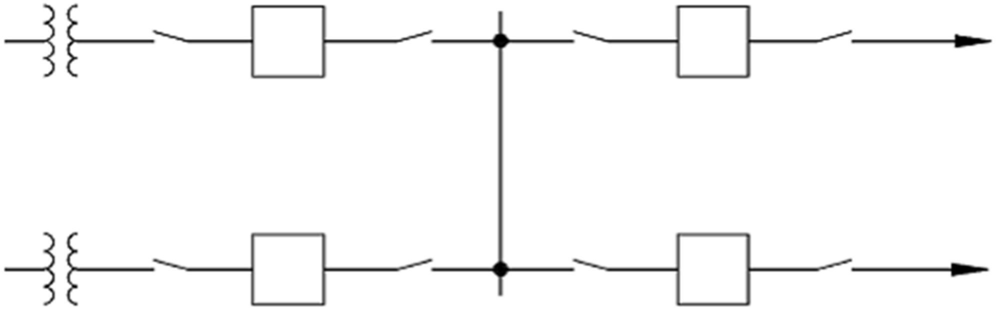
Conventional Design

Conventional Design

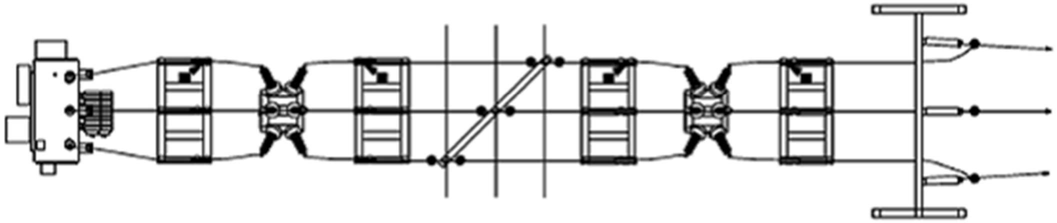
Conventional Design

- **Low Profile (**Standard ”Extruded” Shapes)
  - Wide Flange, Channel, Plates, Structural Tubing (Round, Square, Rectangular)
  - Short Erection Time
  - Aesthetical Pleasing
  - Most Sizes Readily Available
  - Requires Greater Site Area

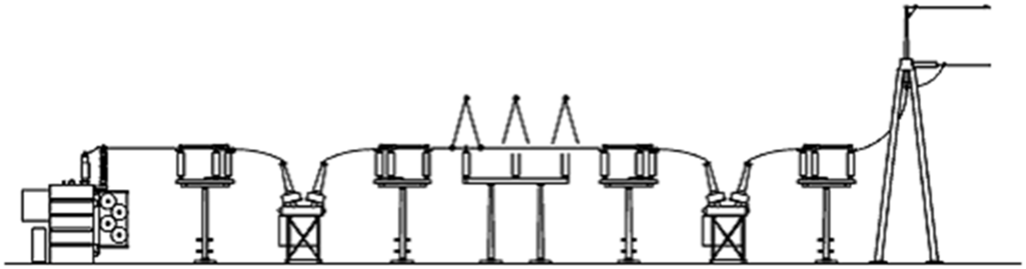
Station Physical Layout



TYPICAL ONE-LINE DIAGRAM



PLAN VIEW—TYPICAL BAY



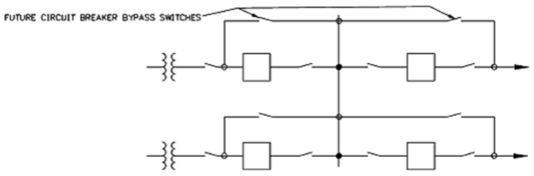
ELEVATION—TYPICAL BAY

Low Profile (tube)

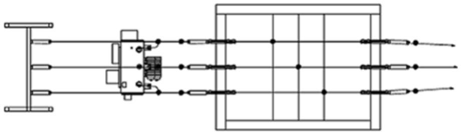
Low Profile (tube)

Low Profile (tube)

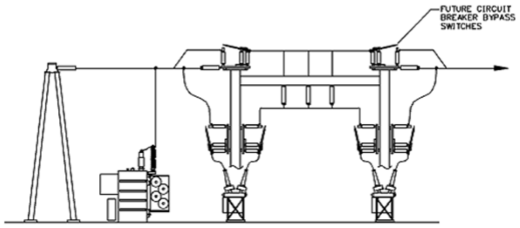
Conventional



TYPICAL ONE-LINE DIAGRAM

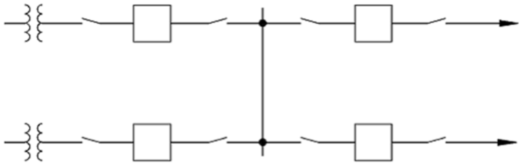


PLAN VIEW–TYPICAL BAY

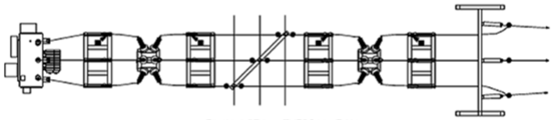


ELEVATON–TYPICAL BAY

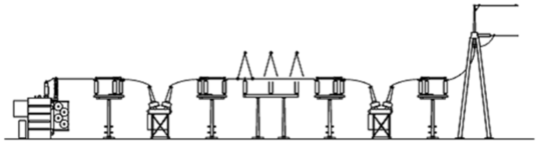
Low Profile



TYPICAL ONE-LINE DIAGRAM



PLAN VIEW–TYPICAL BAY



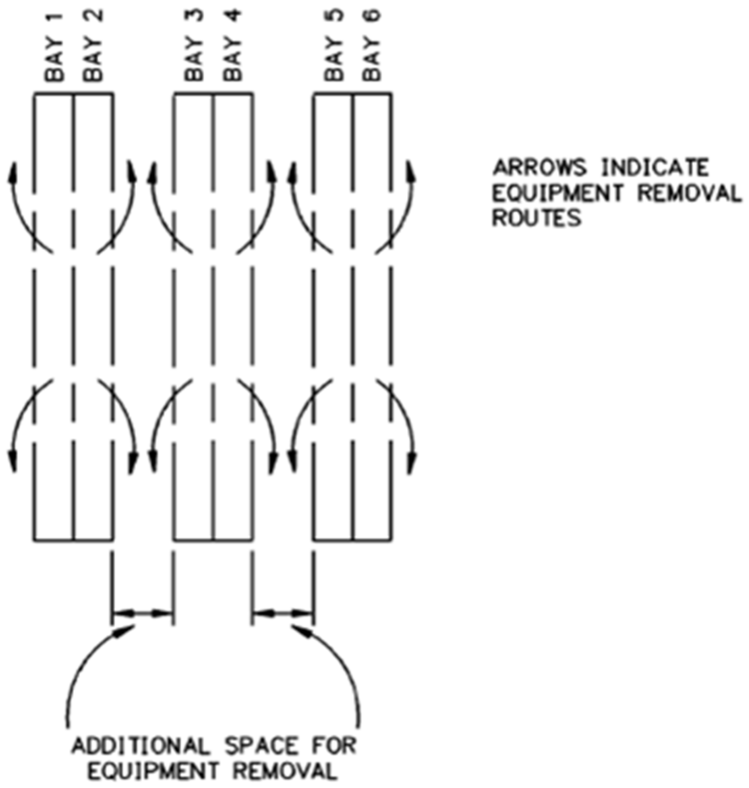
ELEVATION–TYPICAL BAY

Station Physical Layout

- **GIS** (Gas Insulated Substation)

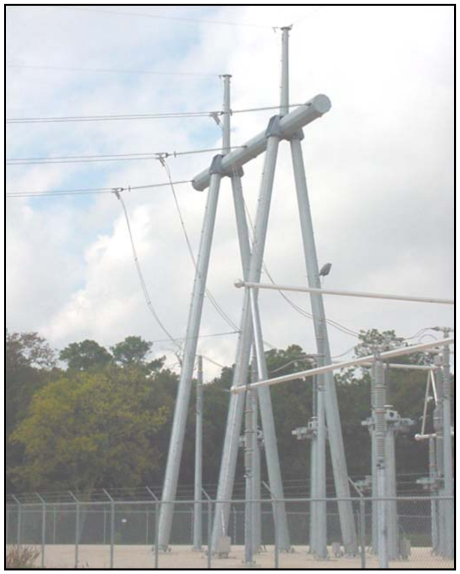
Station Physical Layout

- Maintenance
- Equipment Removal
- Vehicle Mobility
- Exterior Access



Station Physical Layout

- **Common Designs**
  - A-Frame or H-Frame
  - Lattice, Wide Flange, Structural Tubing
  - Inboard or Outboard Leg Design



Deadend Structures

Surge and Lightning Protection

- Design Problems
  - Probabilistic nature of lightning
  - Lack of data due to infrequency of lightning strokes in substations
  - Complexity and economics involved in analyzing a system in detail
  - No known practical method of providing 100% shielding (excluding GIS)

Surge & Lightning Protection

- Common Approaches
  - Lower voltages (69 kV and below): Simplified rules of thumb and empirical methods
    - Fixed Angle
    - Empirical Curves
  - EHV (345 kV and above): Sophisticated electrogeometric model (EGM) studies
    - Whitehead’s EGM
    - Revised EGM
    - Rolling Sphere

Surge & Lightning Protection

- Surge Protection (Arresters)
  - Use Arresters (Station Class)
  - Transformer Protection (High Z Causes High V Reflected Wave)
  - Line Protection (Open End Causes High V Reflected Wave)
  - Systems above 169 kV Require Special Attention
  - IEEE C62.22 – IEEE Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems

Surge & Lightning Protection

- Lightning Protection
  - Strokes to Tall Structures; Strokes to Ground
  - Frequency – Isokeraunic Levels at Station Location
  - Design Methods
    - Fixed Angles (good at or below 69 kV, generally applied up to 138 kV)
    - Empirical Curves (not used widely)
    - Whitehead’s EGM
    - Revised EGM
    - Rolling Sphere
- Combination of Surge Arresters and Lightning Shielding Provides Acceptable Levels of Protection
- IEEE 998 – IEEE Guide for Direct Lightning Stroke Shielding of Substations

A properly designed ground grid is critical for proper surge and lightning protection.

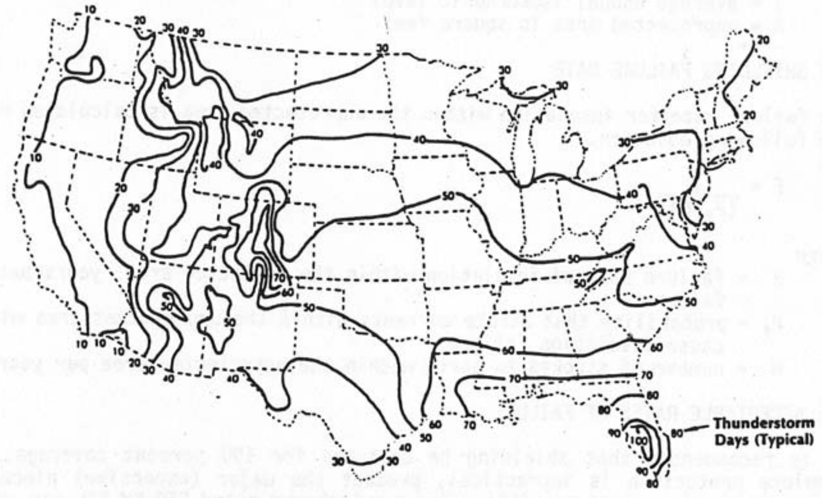
Surge & Lightning Protection

The number of strokes expected to strike the unprotected area each year is calculated, based on the isokeraunic level (see Figure 13) at the substation site using the following equation.

$$N = 1.112 \times 10^{-8}(T)(A)$$

where

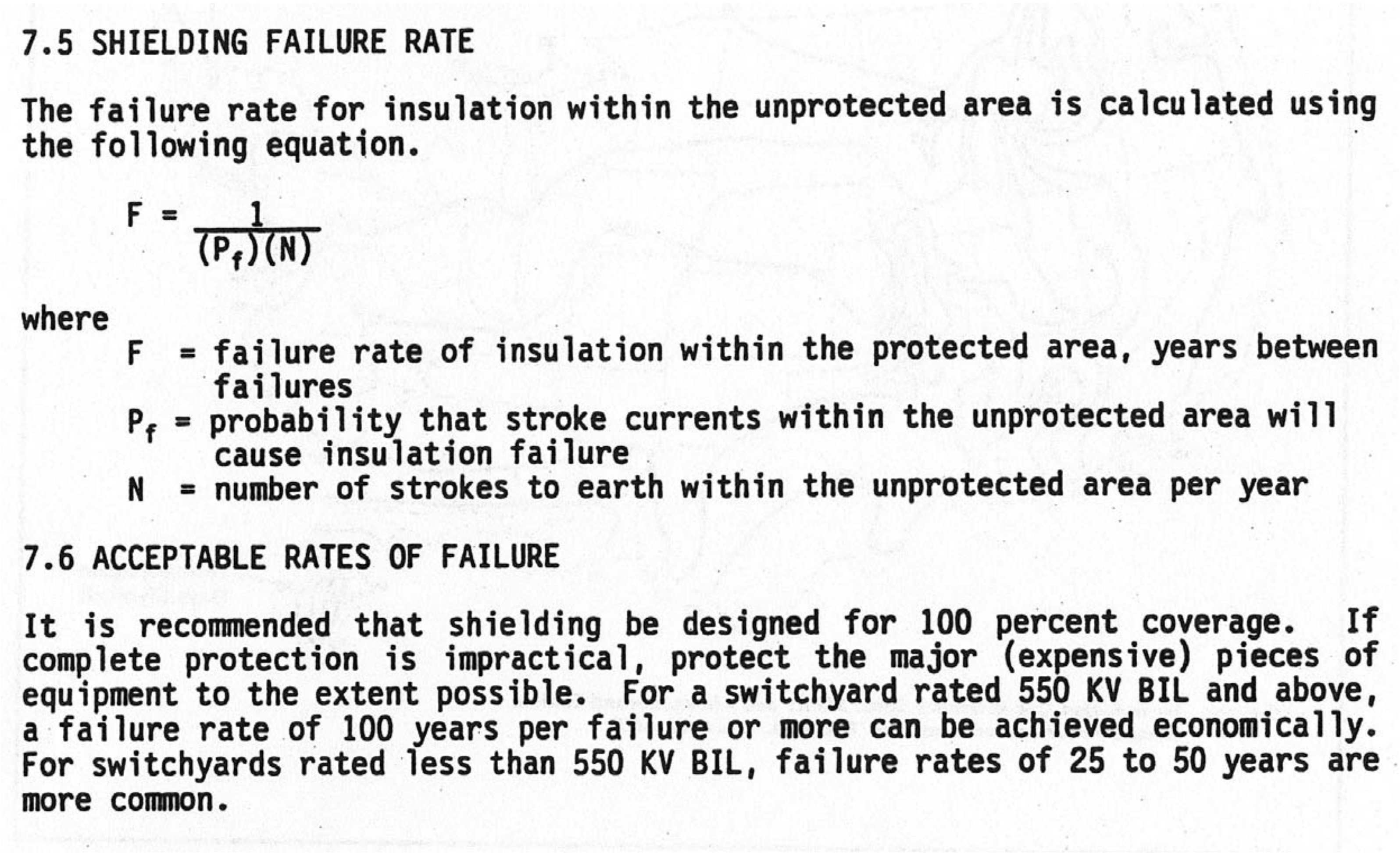
N = number of strokes to earth within the unprotected area per year
T = average annual isokeraunic level
A = unprotected area in square feet



Source: *Transmission Line Reference Book, 345 kV and Above*, **Second Edition, Electric Power Resource Institute, Palo Alto, California, 1982.**

Figure 13
USA Annual Isokeraunic Map

Surge & Lightning Protection



7.5 SHIELDING FAILURE RATE

The failure rate for insulation within the unprotected area is calculated using the following equation.

$$F = \frac{1}{(P_f)(N)}$$

where

F = failure rate of insulation within the protected area, years between failures

P_f = probability that stroke currents within the unprotected area will cause insulation failure

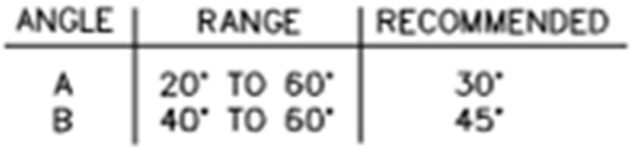
N = number of strokes to earth within the unprotected area per year

7.6 ACCEPTABLE RATES OF FAILURE

It is recommended that shielding be designed for 100 percent coverage. If complete protection is impractical, protect the major (expensive) pieces of equipment to the extent possible. For a switchyard rated 550 KV BIL and above, a failure rate of 100 years per failure or more can be achieved economically. For switchyards rated less than 550 KV BIL, failure rates of 25 to 50 years are more common.

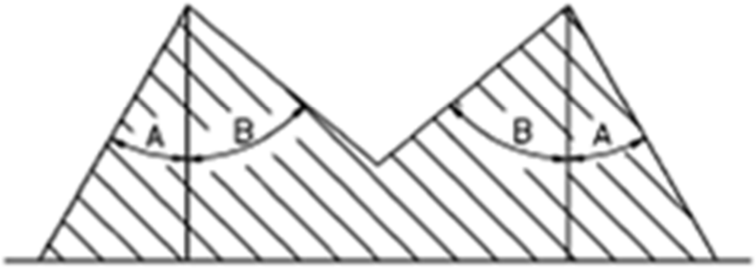
Surge & Lightning Protection

- Fixed Angle Method



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

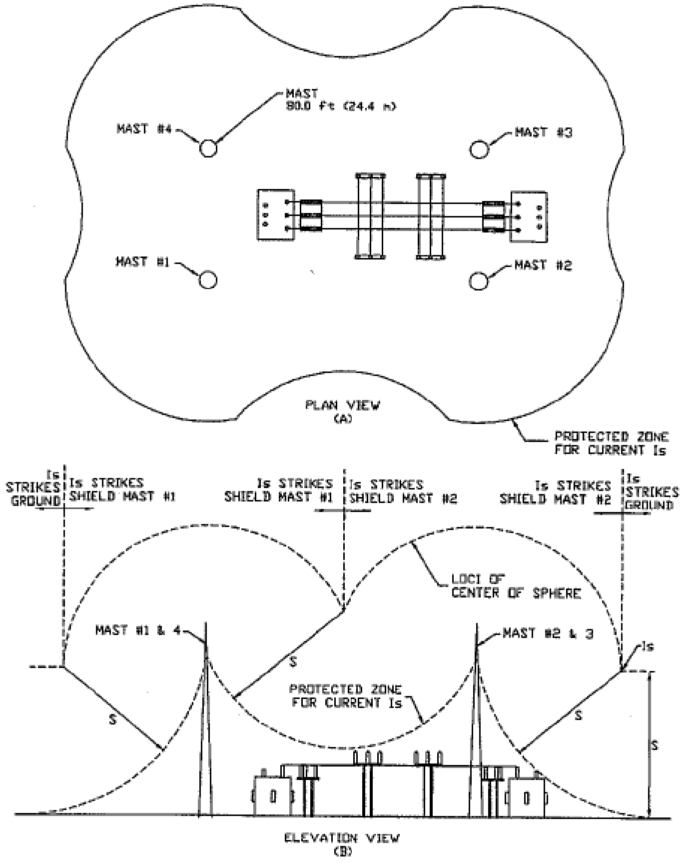
SINGLE MAST OR SHIELD WIRE



TWO MASTS OR SHIELD WIRES

Surge & Lightning Protection

Rolling Sphere Method

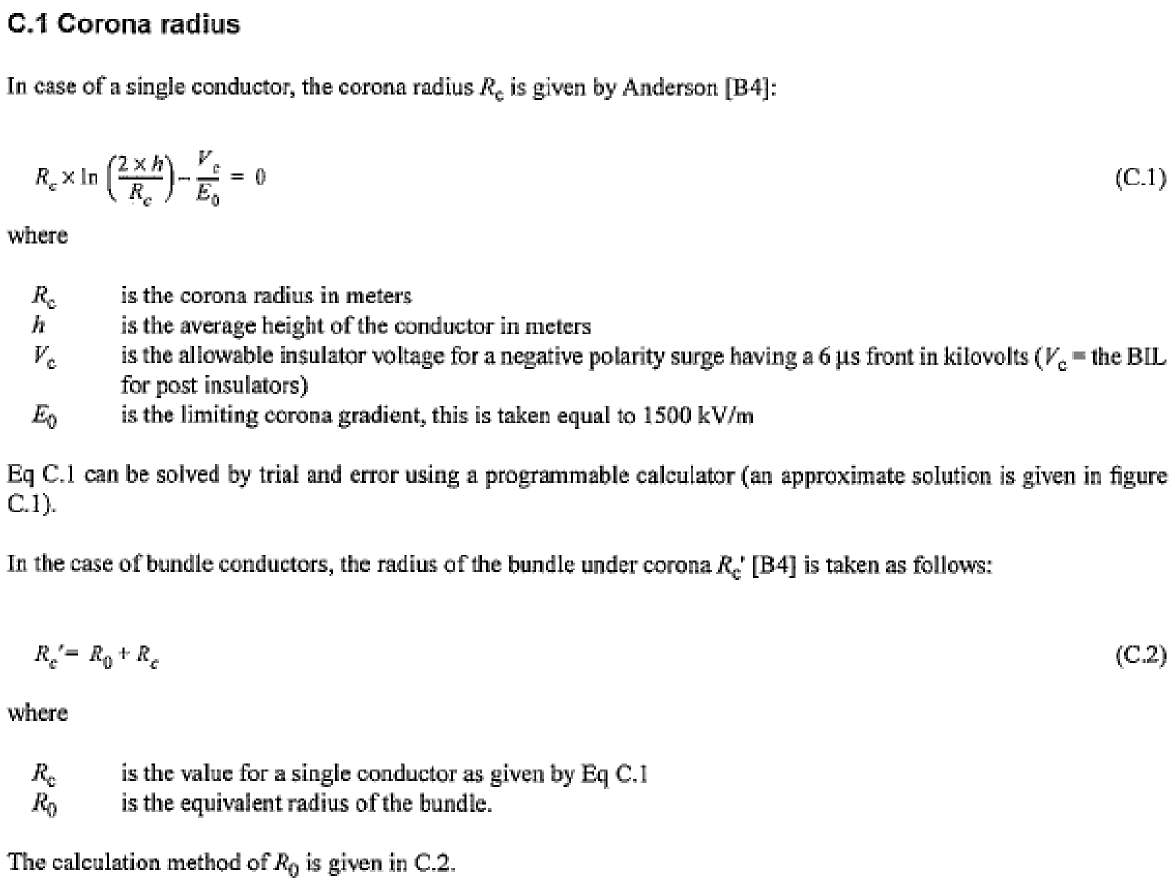


Source: Adapted from [B74]

Figure 5-7 —Multiple shield mast protection for stroke current I_s

Surge & Lightning Protection

Rolling Sphere Method



C.1 Corona radius

In case of a single conductor, the corona radius R_c is given by Anderson [B4]:

$$R_c \times \ln\left(\frac{2 \times h}{R_c}\right) - \frac{V_c}{E_0} = 0 \qquad \text{(C.1)}$$

where

R_c is the corona radius in meters
h is the average height of the conductor in meters
V_c is the allowable insulator voltage for a negative polarity surge having a 6 μs front in kilovolts (V_c = the BIL for post insulators)
E_0 is the limiting corona gradient, this is taken equal to 1500 kV/m

Eq C.1 can be solved by trial and error using a programmable calculator (an approximate solution is given in figure C.1).

In the case of bundle conductors, the radius of the bundle under corona R_c' [B4] is taken as follows:

$$R_c' = R_0 + R_c \qquad \text{(C.2)}$$

where

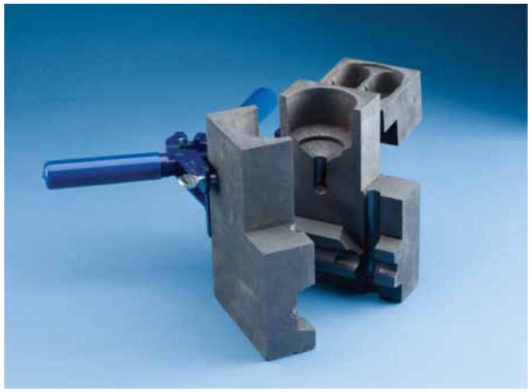
R_c is the value for a single conductor as given by Eq C.1
R_0 is the equivalent radius of the bundle.

The calculation method of R_0 is given in C.2.

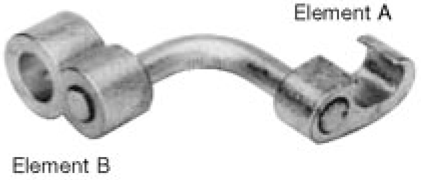
Grounding Considerations

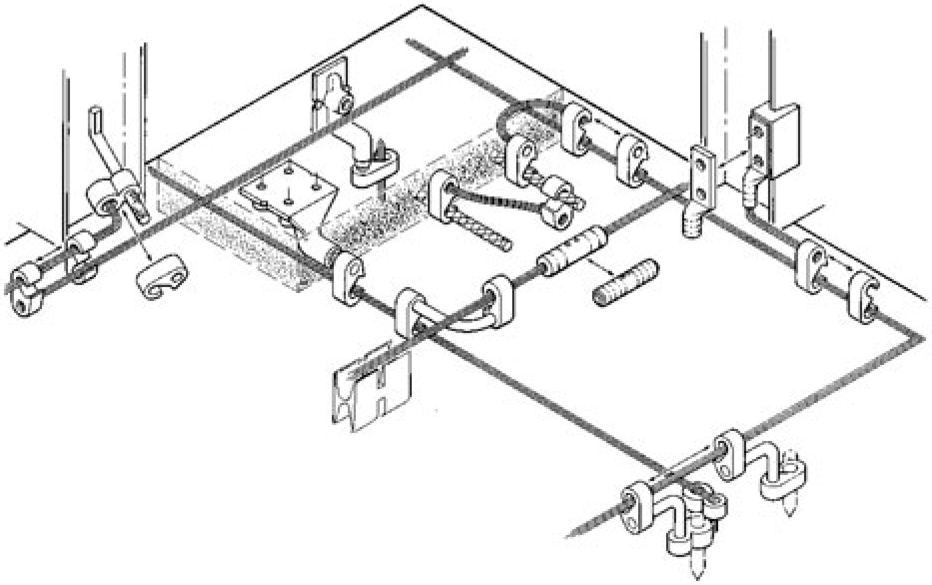
- IEEE 80 – IEEE Guide for Safety in AC Substation Grounding
  - Safety Risks
  - Humans as Electrical Components
  - Soil Modeling
  - Fault Currents and Voltage Rise
  - Demands Use of Analytical Software
- NESC
  - Points of Connection
  - Messengers & Guys, Fences
  - Grounding Conductors, Ampacity, Strength, Connections
  - Grounding Electrodes
  - Ground Resistance Requirements

Grounding



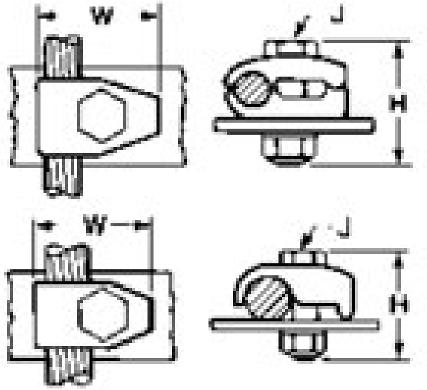
Grounding – Exothermic

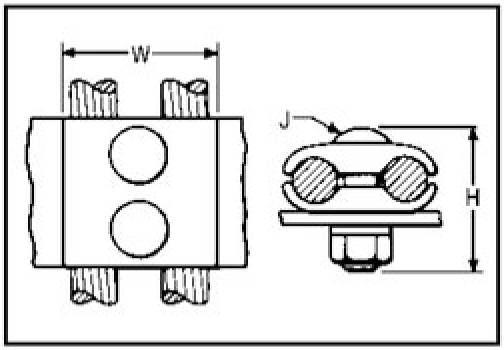


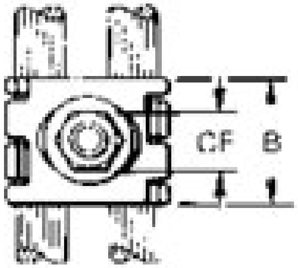


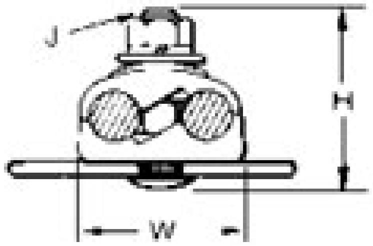
Grounding – Compression

Grounding – Mechanical









OBJECTIVES

- To Identify Components of a Grounding System
- To Review Key Design Considerations and Parameters Needed for a Grounding Analysis
- To Review the Grounding Problem
- To Identify Grounding Analysis Methods and Applicability

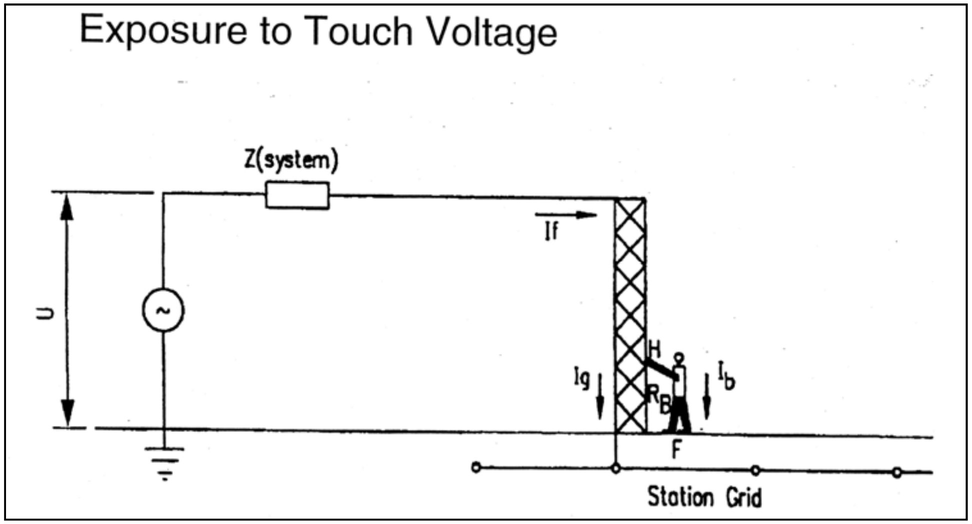
Grounding Design

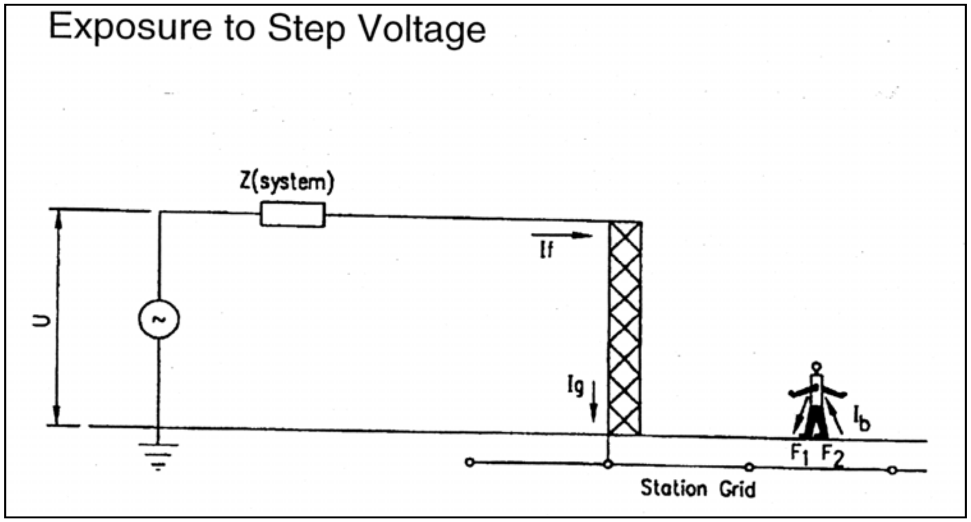
1. **Assure that persons in or near any substation are not exposed to electric shock above tolerable limits.**
2. **Provide means to dissipate normal and abnormal electric currents into the earth without exceeding operating or equipment limits.**

Grounding Objectives

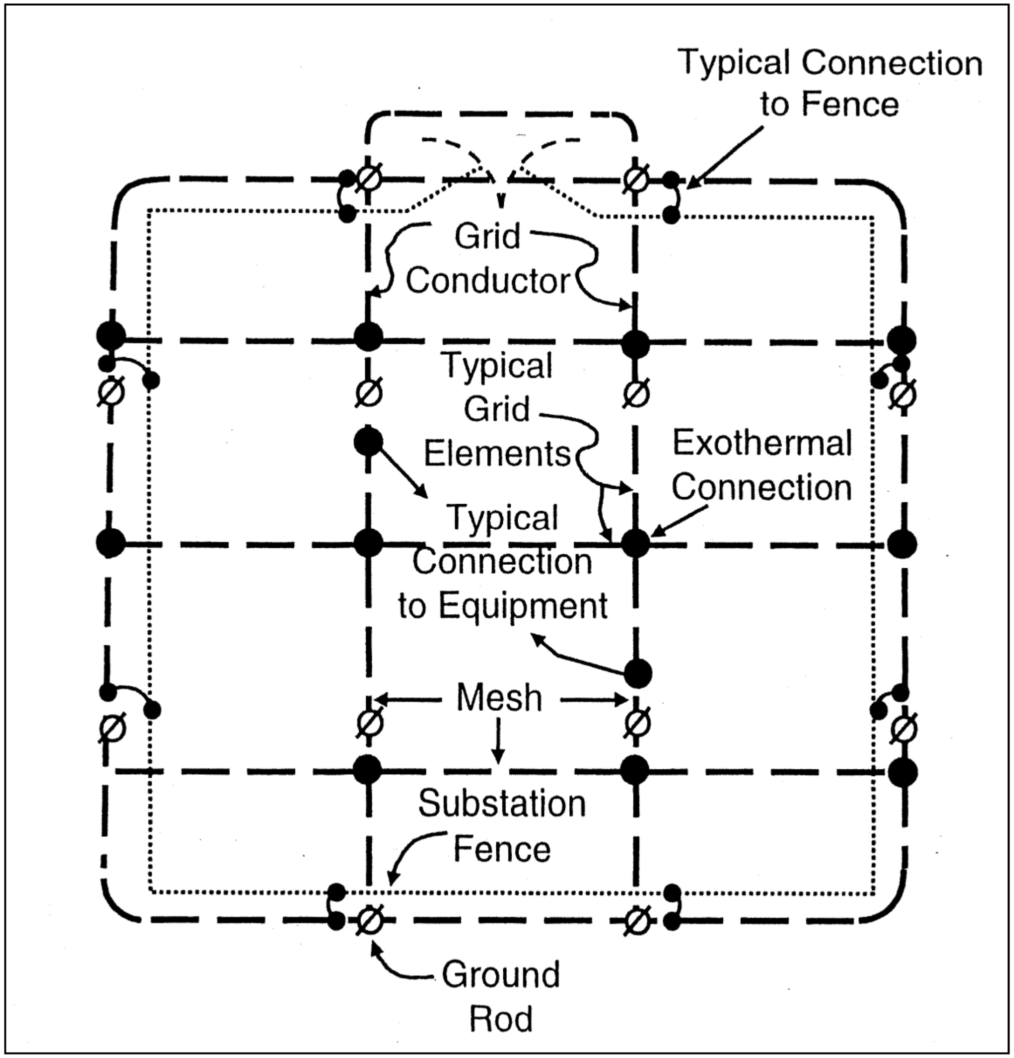
1. **High fault current to ground**
2. **Soil resistivity and distribution of ground currents**
3. **Body bridging two points of high potential difference**
4. **Absence of sufficient contact resistance**
5. **Duration of the fault and body contact**

Cause of Electric Shock


Exposure to Touch Voltage


Exposure to Step Voltage

Basic Shock Situations



Simple Grid Design

Protection & Control

One-Line Diagrams

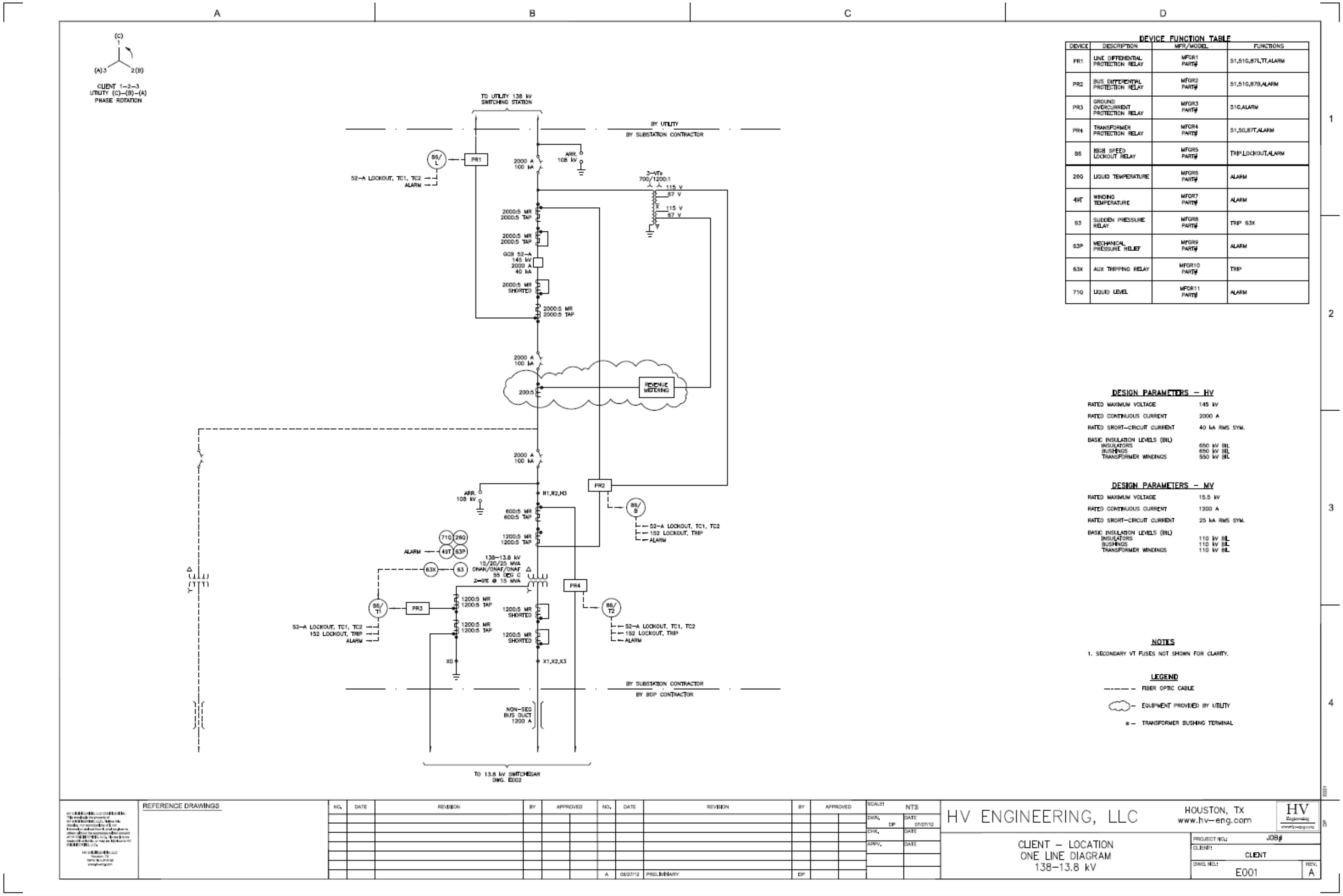
- The one-line diagram is probably the single most important document in the substation design package.
- The one-line diagram defines the design parameters and scope of the design…a road map

One-Line Diagrams

Key elements that should be included on relaying one-lines

- Substation Configuration
- Equipment Ratings
- Design Parameters
- Phasor Rotation Diagram
- Delineation of Scope
- Provisions for Future Expansion

One-Line Diagrams



DEVICE FUNCTION TABLE

DEVICE	DESCRIPTION	MFR/MODEL	FUNCTIONS
PR1	LINE DIFFERENTIAL PROTECTION RELAY	MFGR1 PART#	51,51G,87L,TT,ALARM
PR2	BUS DIFFERENTIAL PROTECTION RELAY	MFGR2 PART#	51,51G,87B,ALARM
PR3	GROUND OVERCURRENT PROTECTION RELAY	MFGR3 PART#	51G,ALARM
PR4	TRANSFORMER PROTECTION RELAY	MFGR4 PART#	51,50,87T,ALARM
86	HIGH SPEED LOCKOUT RELAY	MFGR5 PART#	TRIP,LOCKOUT,ALARM
26Q	LIQUID TEMPERATURE	MFGR6 PART#	ALARM
49T	WINDING TEMPERATURE	MFGR7 PART#	ALARM
63	SUDDEN PRESSURE RELAY	MFGR8 PART#	TRIP 63X
63P	MECHANICAL PRESSURE RELIEF	MFGR9 PART#	ALARM
63X	AUX TRIPPING RELAY	MFGR10 PART#	TRIP
71Q	LIQUID LEVEL	MFGR11 PART#	ALARM

DESIGN PARAMETERS – HV

RATED MAXIMUM VOLTAGE	145 kV
RATED CONTINUOUS CURRENT	2000 A
RATED SHORT–CIRCUIT CURRENT	40 kA RMS SYM.
BASIC INSULATION LEVELS (BIL)	
INSULATORS	650 kV BIL
BUSHINGS	650 kV BIL
TRANSFORMER WINDINGS	550 kV BIL

DESIGN PARAMETERS – MV

RATED MAXIMUM VOLTAGE	15.5 kV
RATED CONTINUOUS CURRENT	1200 A
RATED SHORT–CIRCUIT CURRENT	25 kA RMS SYM.
BASIC INSULATION LEVELS (BIL)	
INSULATORS	110 kV BIL
BUSHINGS	110 kV BIL
TRANSFORMER WINDINGS	110 kV BIL

NOTES

1. SECONDARY VT FUSES NOT SHOWN FOR CLARITY.

LEGEND

– – – – – –	FIBER OPTIC CABLE
☁ –	EQUIPMENT PROVIDED BY UTILITY
• –	TRANSFORMER BUSHING TERMINAL

REFERENCE DRAWINGS

NO.	DATE	REVISION	BY	APPROVED		NO.	DATE	REVISION	BY	APPROVED	
						A	08/27/12	PRELIMINARY	DP		

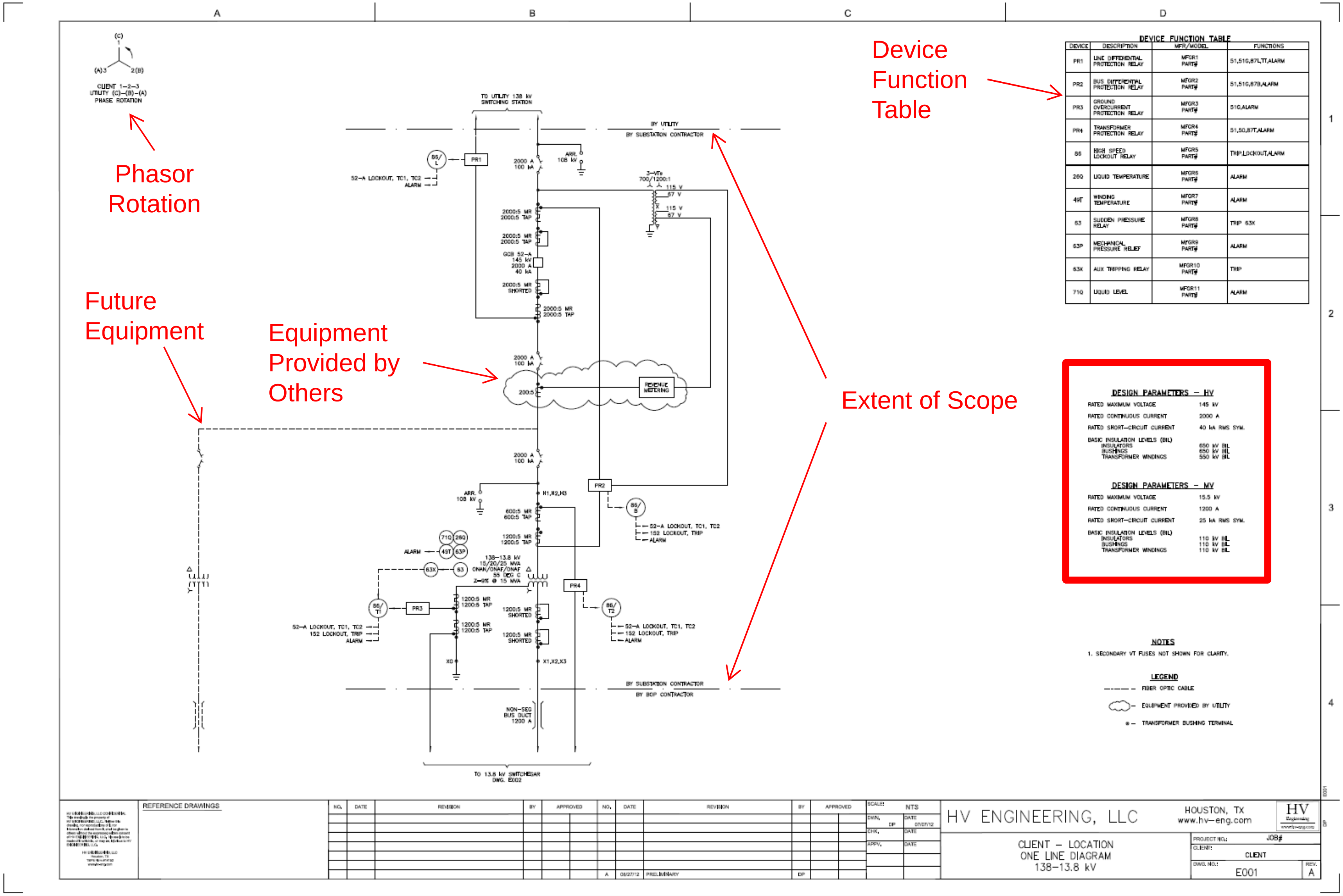
SCALE: NTS
DWN. DP
DATE 07/07/12
CHK.
DATE
APPV.
DATE

HV ENGINEERING, LLC
HOUSTON, TX
www.hv–eng.com

CLIENT – LOCATION
ONE LINE DIAGRAM
138–13.8 kV

PROJECT NO.: JOB#
CLIENT: CLIENT
DWG. NO.: E001
REV. A

One-Line Diagrams



Device Function Table

Phasor Rotation

Future Equipment

Equipment Provided by Others

Extent of Scope

DEVICE FUNCTION TABLE

DEVICE	DESCRIPTION	MFR/MODEL	FUNCTIONS
PR1	LINE DIFFERENTIAL PROTECTION RELAY	MFGR1 PART#	51,51G,87L,TT,ALARM
PR2	BUS DIFFERENTIAL PROTECTION RELAY	MFGR2 PART#	51,51G,87B,ALARM
PR3	GROUND OVERCURRENT PROTECTION RELAY	MFGR3 PART#	51G,ALARM
PR4	TRANSFORMER PROTECTION RELAY	MFGR4 PART#	51,50,87T,ALARM
86	HIGH SPEED LOCKOUT RELAY	MFGR5 PART#	TRIP,LOCKOUT,ALARM
26Q	LIQUID TEMPERATURE	MFGR6 PART#	ALARM
49T	WINDING TEMPERATURE	MFGR7 PART#	ALARM
63	SUDDEN PRESSURE RELAY	MFGR8 PART#	TRIP 63X
63P	MECHANICAL PRESSURE RELIEF	MFGR9 PART#	ALARM
63X	AUX TRIPPING RELAY	MFGR10 PART#	TRIP
71Q	LIQUID LEVEL	MFGR11 PART#	ALARM

DESIGN PARAMETERS – HV

RATED MAXIMUM VOLTAGE	145 kV
RATED CONTINUOUS CURRENT	2000 A
RATED SHORT–CIRCUIT CURRENT	40 kA RMS SYM.
BASIC INSULATION LEVELS (BIL)	
INSULATORS	650 kV BIL
BUSHINGS	650 kV BIL
TRANSFORMER WINDINGS	550 kV BIL

DESIGN PARAMETERS – MV

RATED MAXIMUM VOLTAGE	15.5 kV
RATED CONTINUOUS CURRENT	1200 A
RATED SHORT–CIRCUIT CURRENT	25 kA RMS SYM.
BASIC INSULATION LEVELS (BIL)	
INSULATORS	110 kV BIL
BUSHINGS	110 kV BIL
TRANSFORMER WINDINGS	110 kV BIL

NOTES

1. SECONDARY VT FUSES NOT SHOWN FOR CLARITY.

LEGEND

– – – – – FIBER OPTIC CABLE

☁ – EQUIPMENT PROVIDED BY UTILITY

● – TRANSFORMER BUSHING TERMINAL

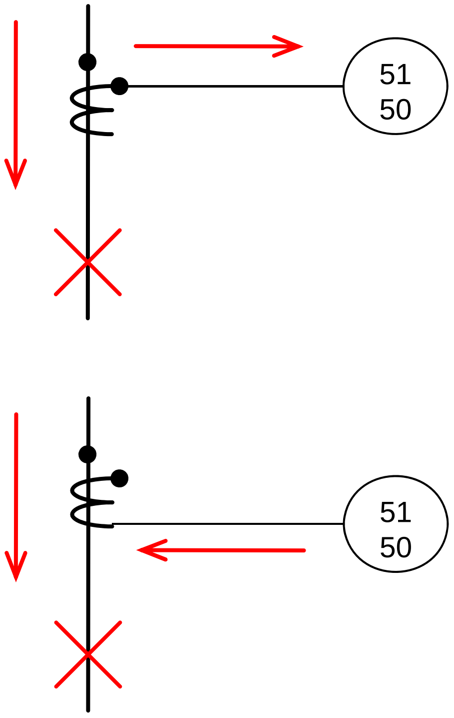
One-Line Diagrams

- Modern microprocessor relays are fairly complex
- Functionality typically can not be adequate illustrated between the one-line diagram and schematic diagrams
- Creating Logic Diagrams is strongly recommended.

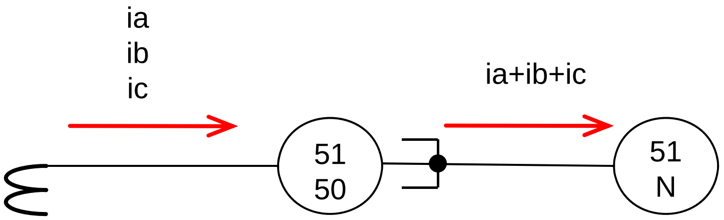
Protection & Control

- Protection
  - Fundamentals
  - Bus
  - Transformers
  - Motors
  - Generators
  - Line & Circuits
- Control
  - Primary/Back-up Systems
  - Breaker Failure
  - Reclosing
  - Pilot Systems & Communication Channels

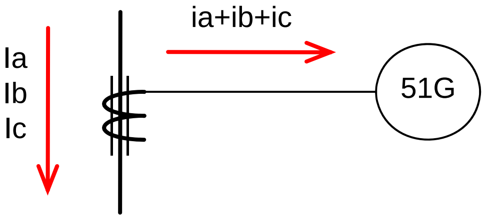
A.C. Fundamentals Phasor Relationships



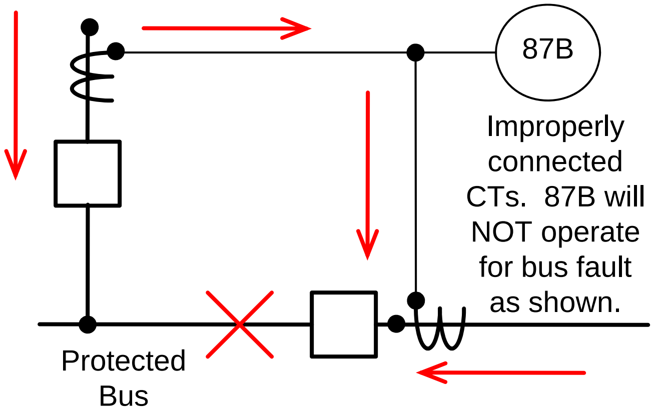
IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes - IEEE Std C37.110



Residual CT connection

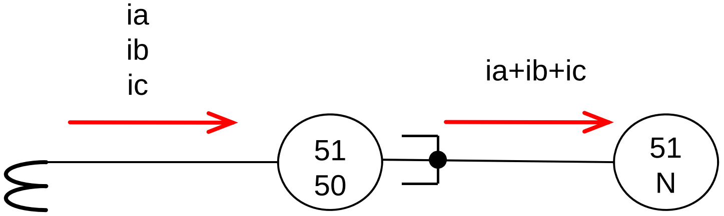


Zero sequence CT

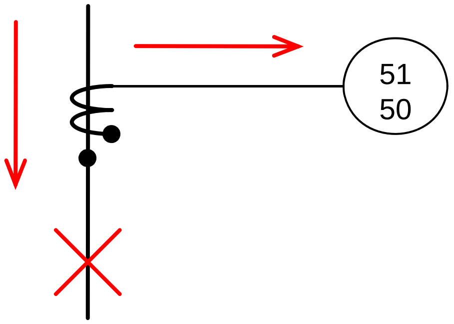


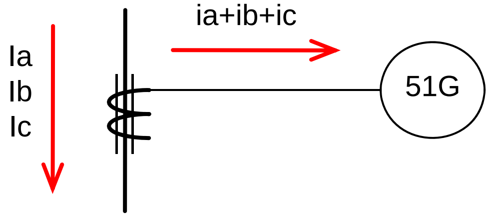
Improperly connected CTs. 87B will NOT operate for bus fault as shown.

A.C. Fundamentals
Phasor Relationships

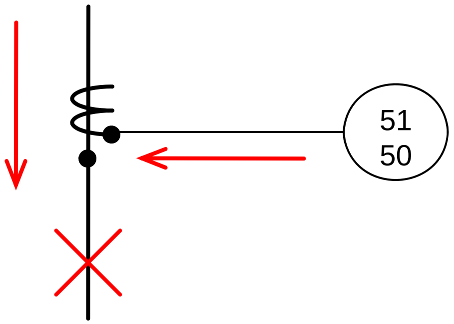


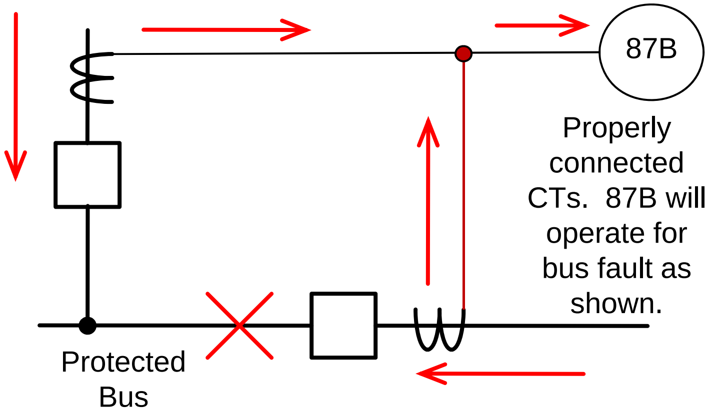
Residual CT connection





Zero sequence CT

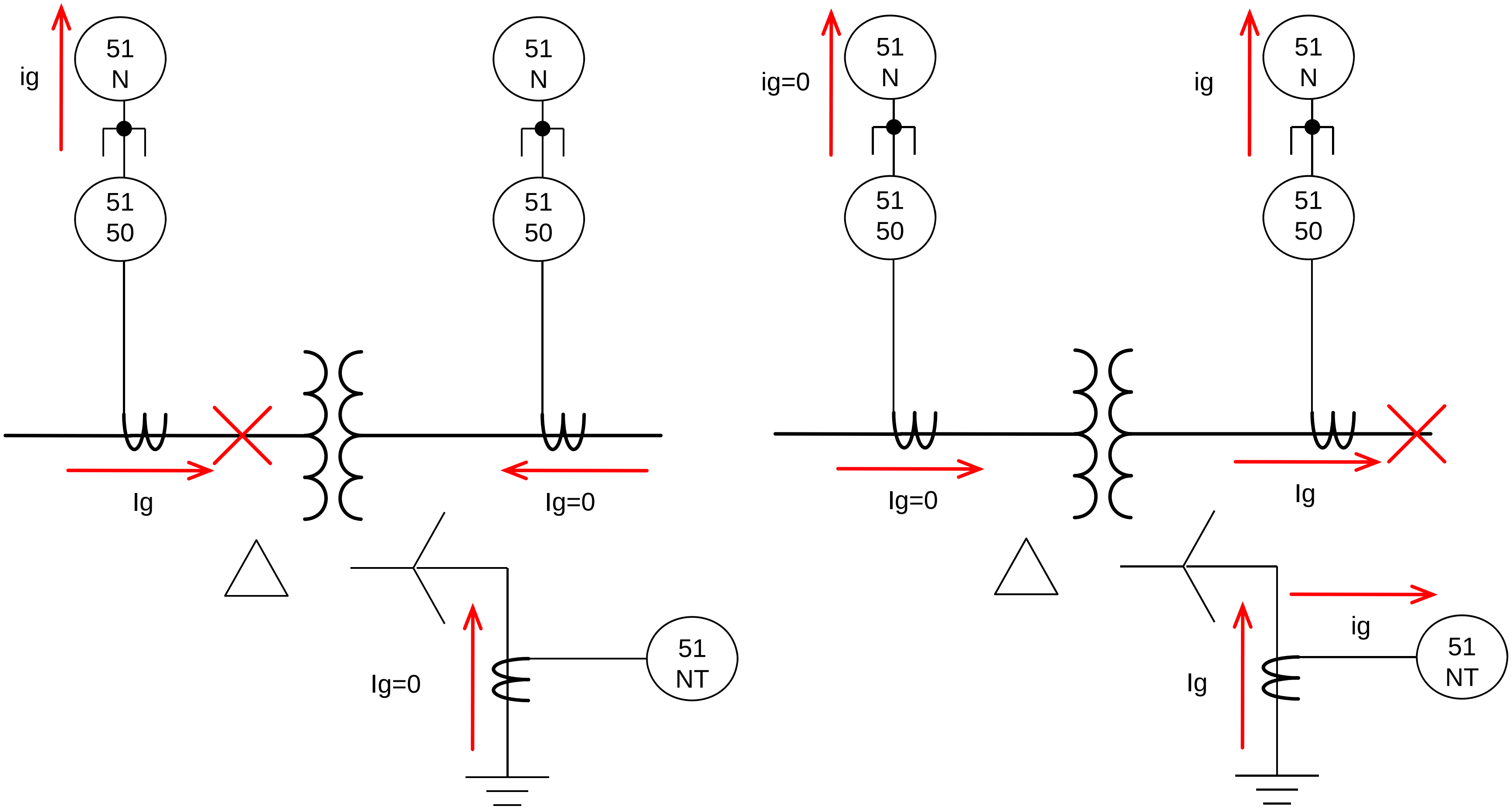




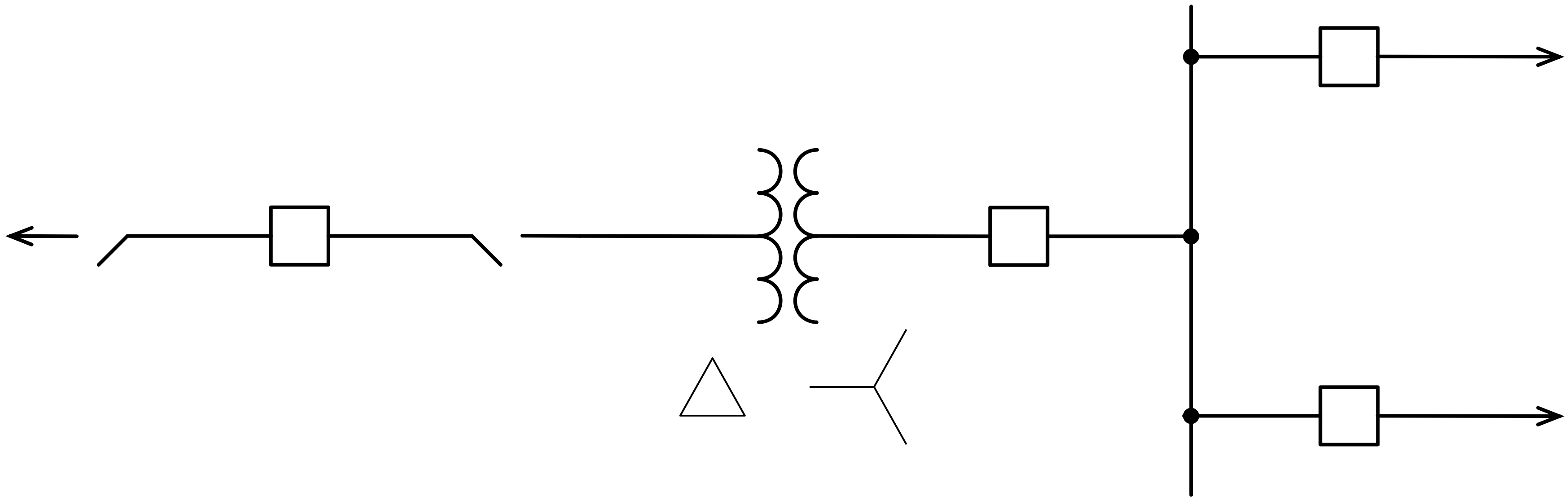
Properly connected CTs. 87B will operate for bus fault as shown.

IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes - IEEE Std C37.110

A.C. Fundamentals



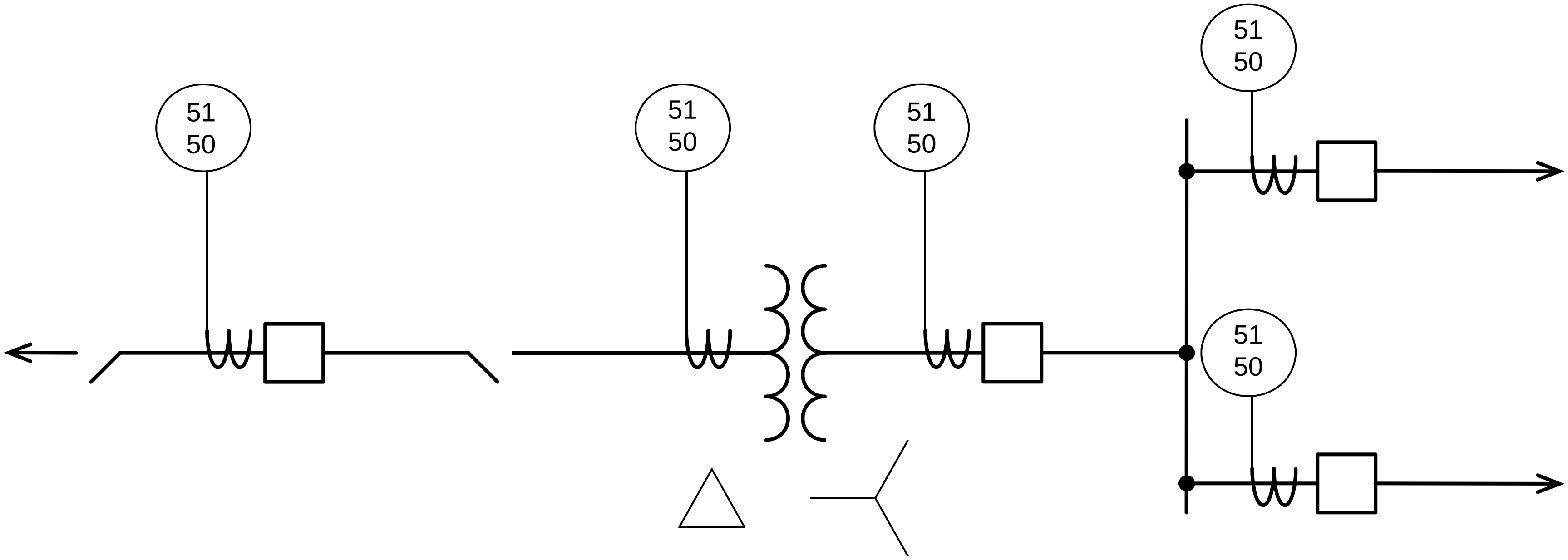
Tap Substation



Tap Substation

- Phase Protection
  - Overcurrent

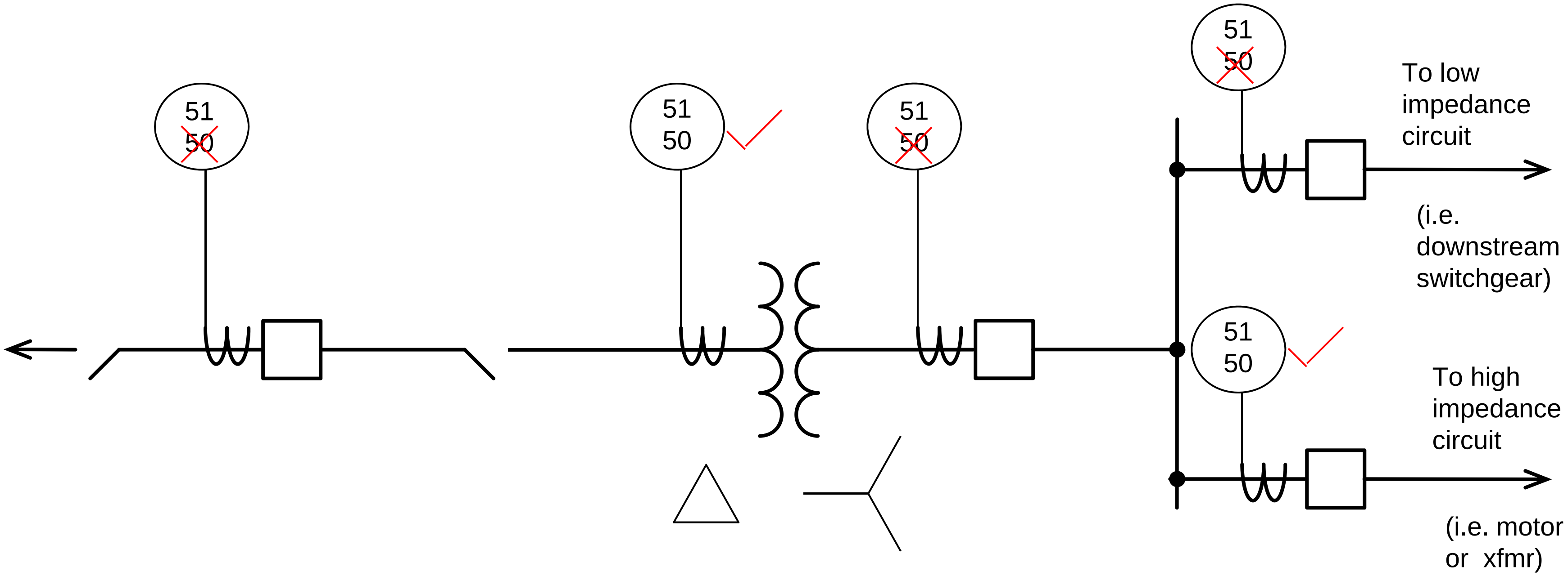
Should 50 elements be set on all relays?



Tap Substation

- Phase Protection
  - Overcurrent

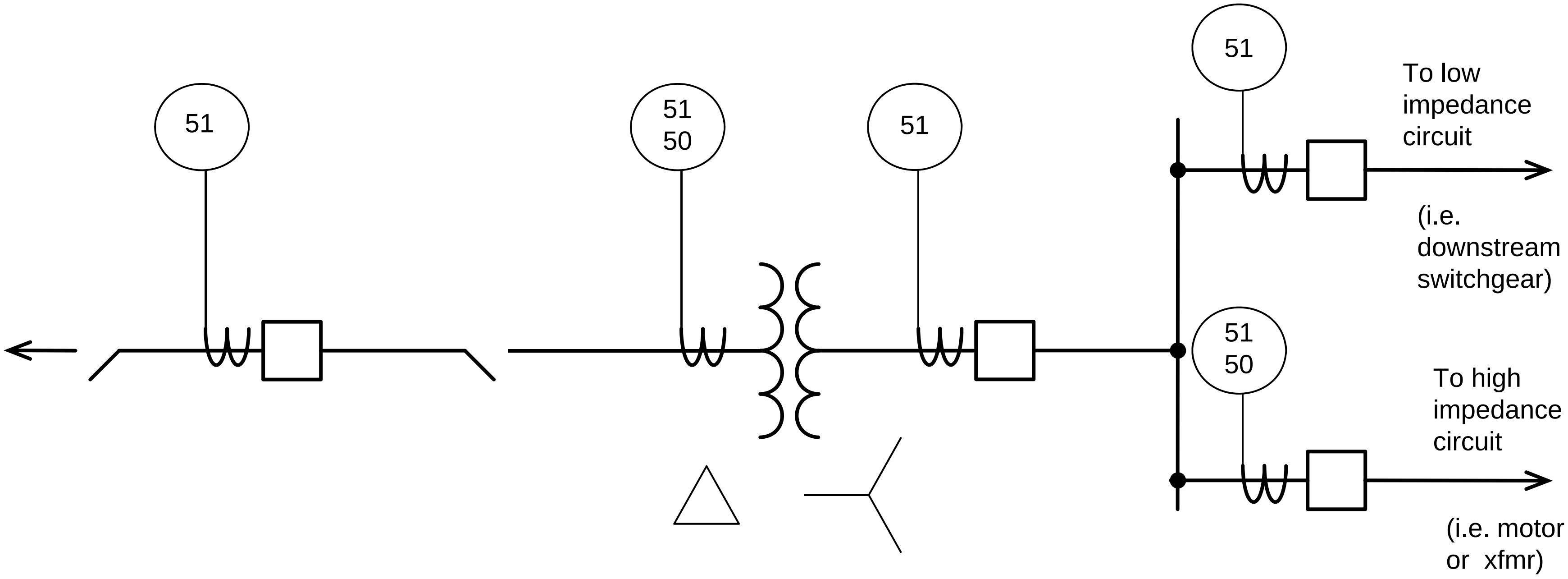
Should 50 elements be set on all relays?



Tap Substation

- Phase Protection
  - Overcurrent

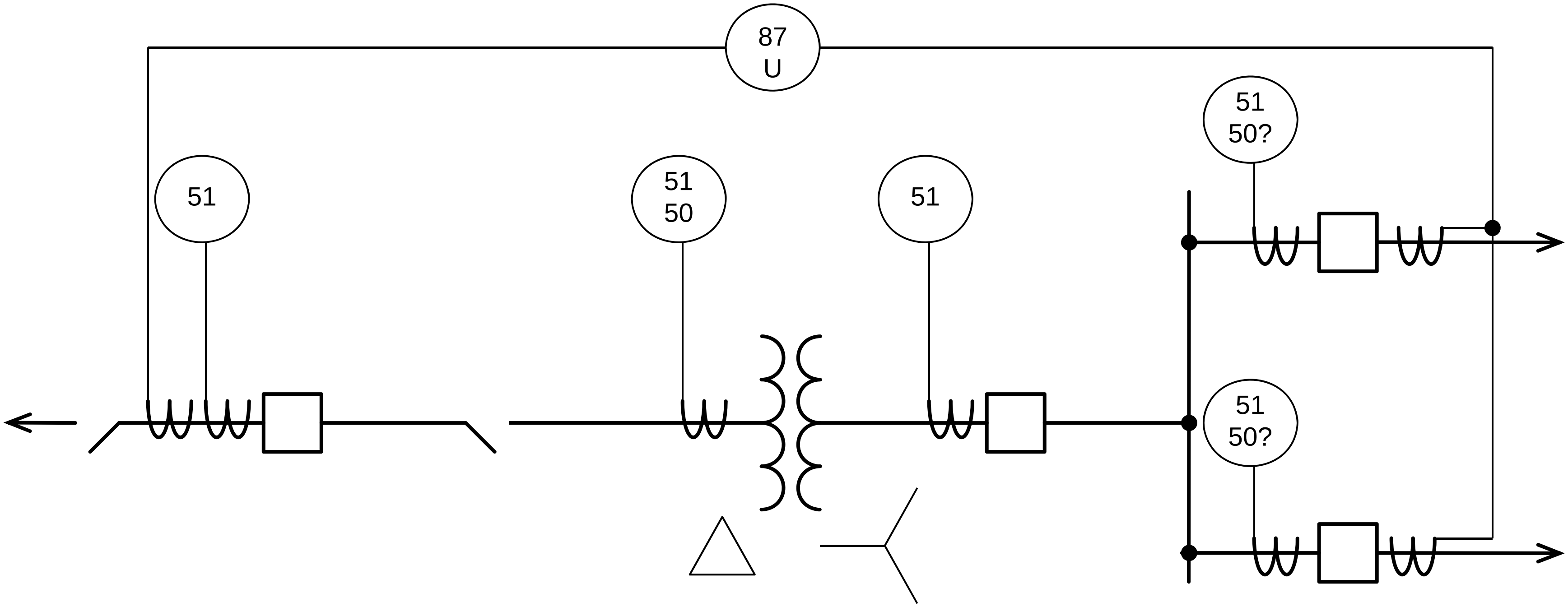
Should 50 elements be set on all relays?



Tap Substation

- Phase Protection
  - Unit Differential
  - Overcurrent

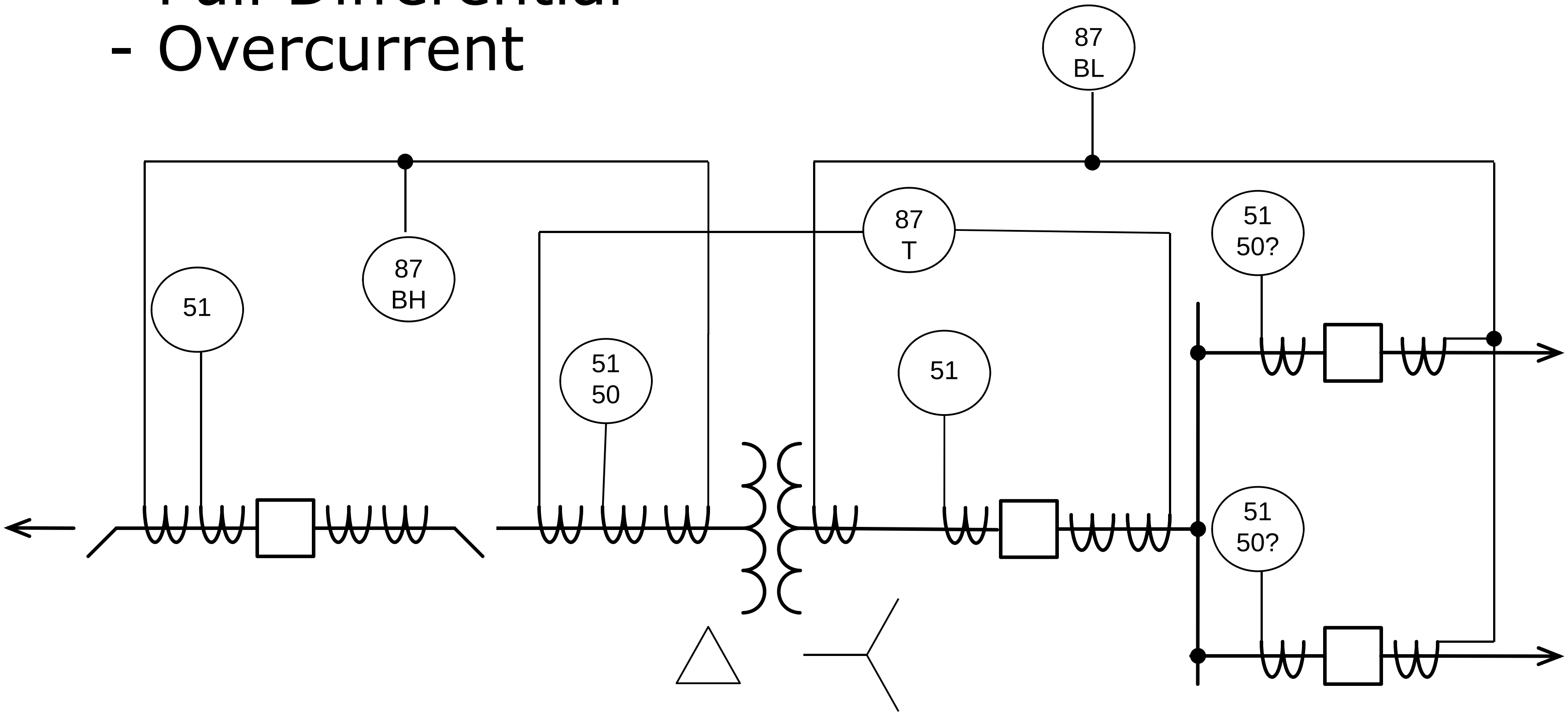
This configuration is not preferred.



- Pros
  - Lower cost
- Cons
  - Lower selectivity

Tap Substation

- Phase Protection
  - Full Differential
  - Overcurrent



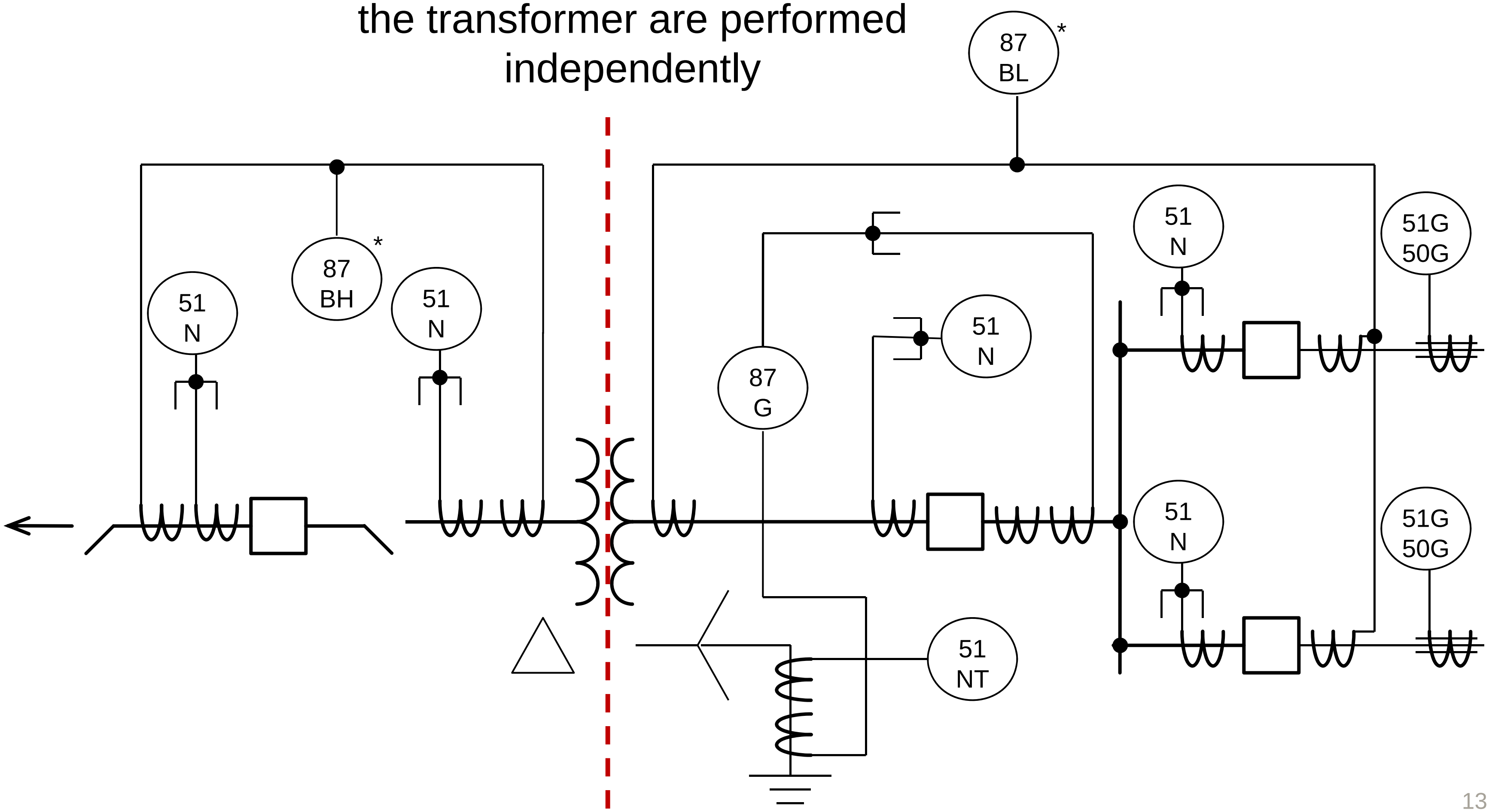
- Pros
  - Higher selectivity
- Cons
  - Higher cost

Tap Substation

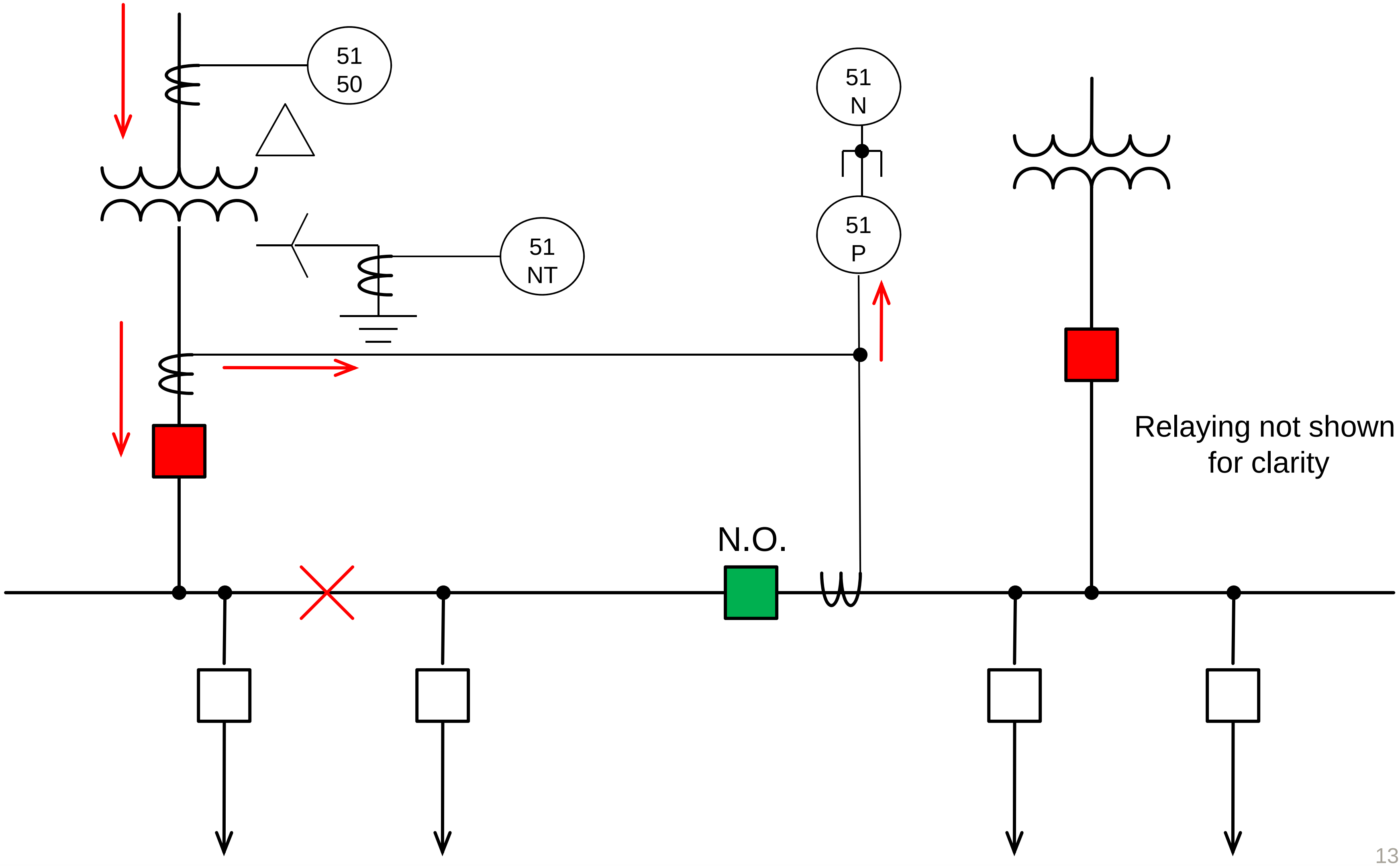
- Ground Protection

(*) relays measure phase quantities, but are often set to operate for ground faults in the zone of protection.

Ground coordination on each side of the transformer are performed independently

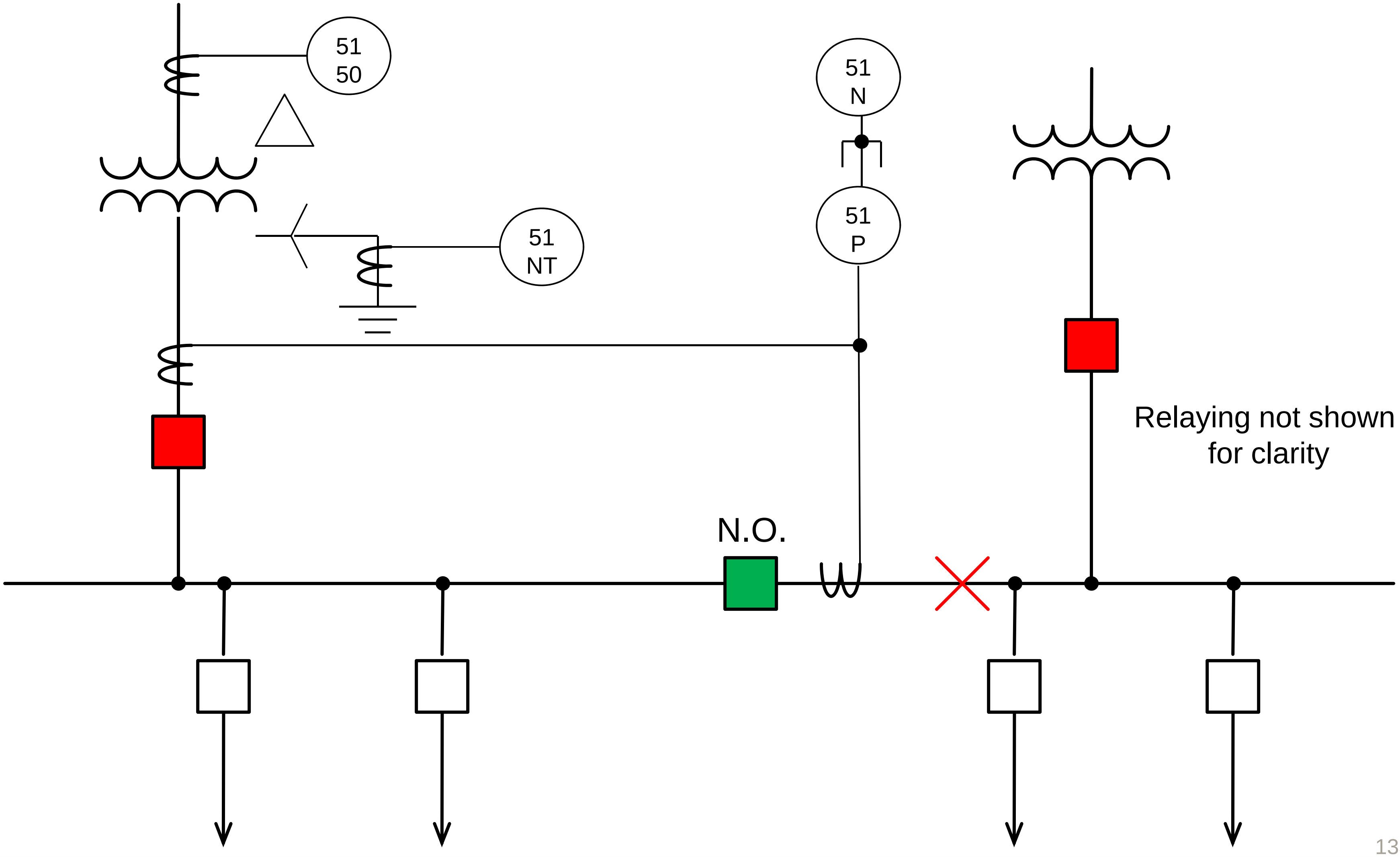


Secondary Selective Arrangement – N.O. Tie



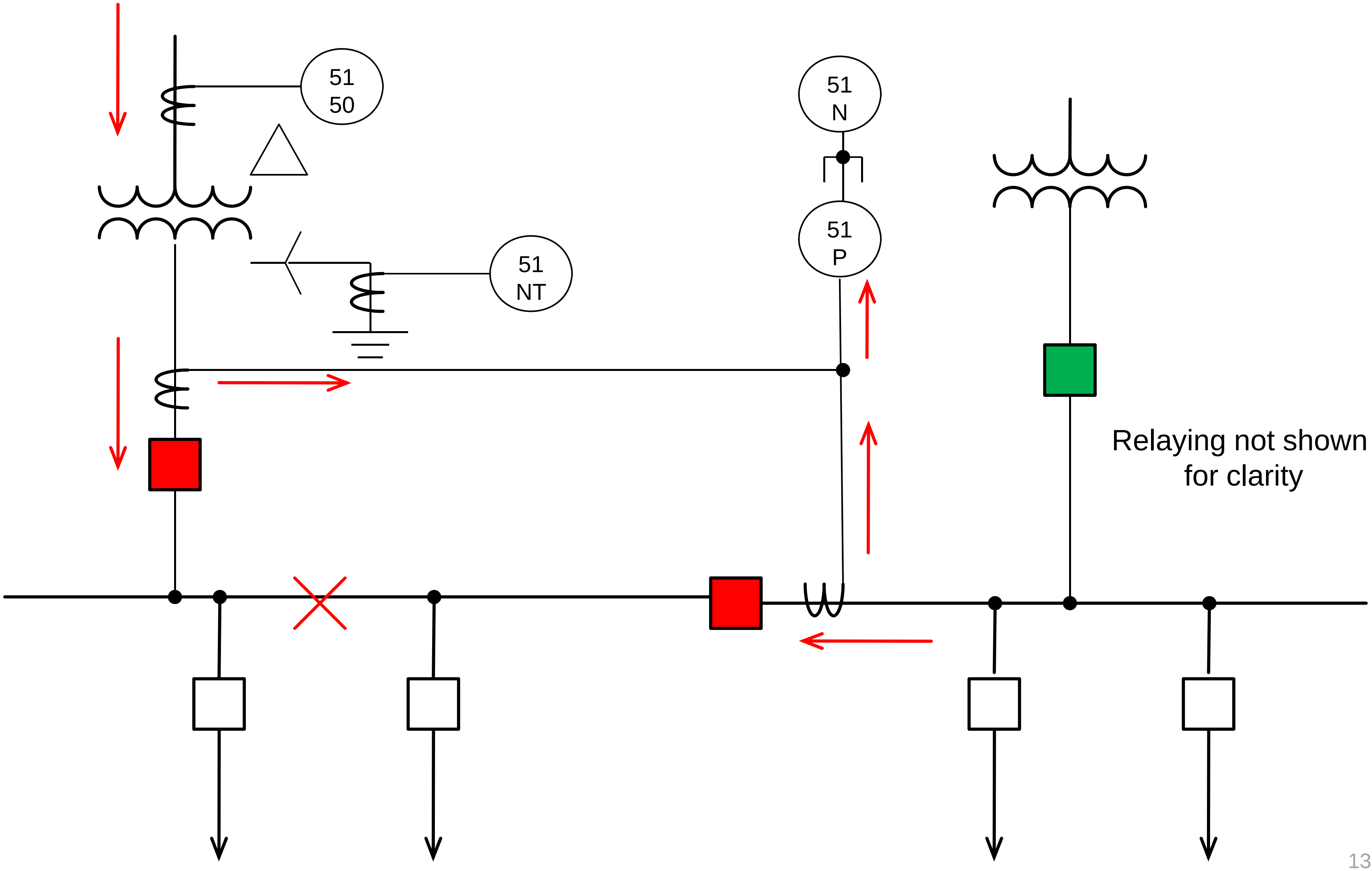
Relaying not shown for clarity

Secondary Selective Arrangement – N.O. Tie



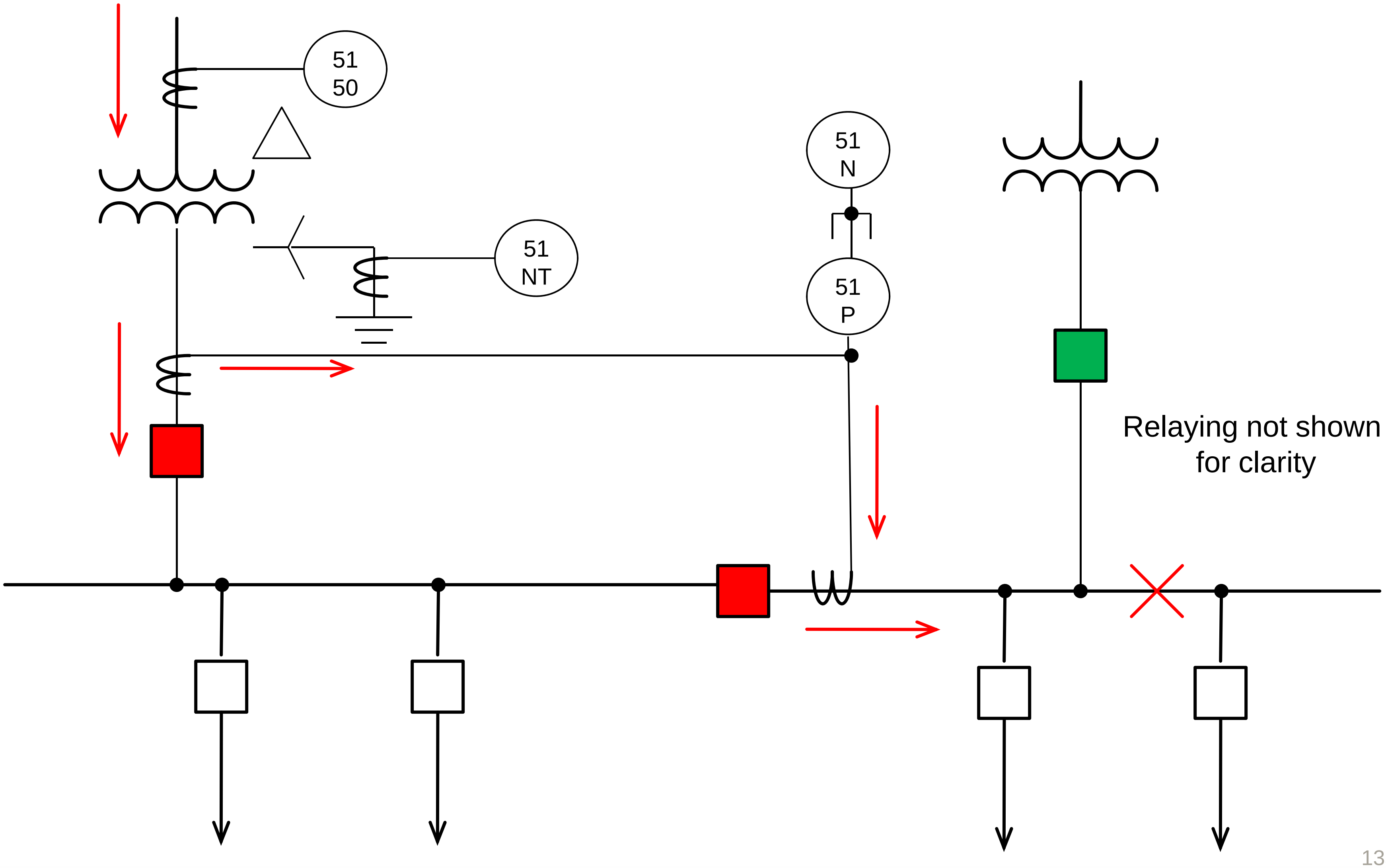
Relaying not shown for clarity

Secondary Selective Arrangement – N.O. Tie



Relaying not shown for clarity

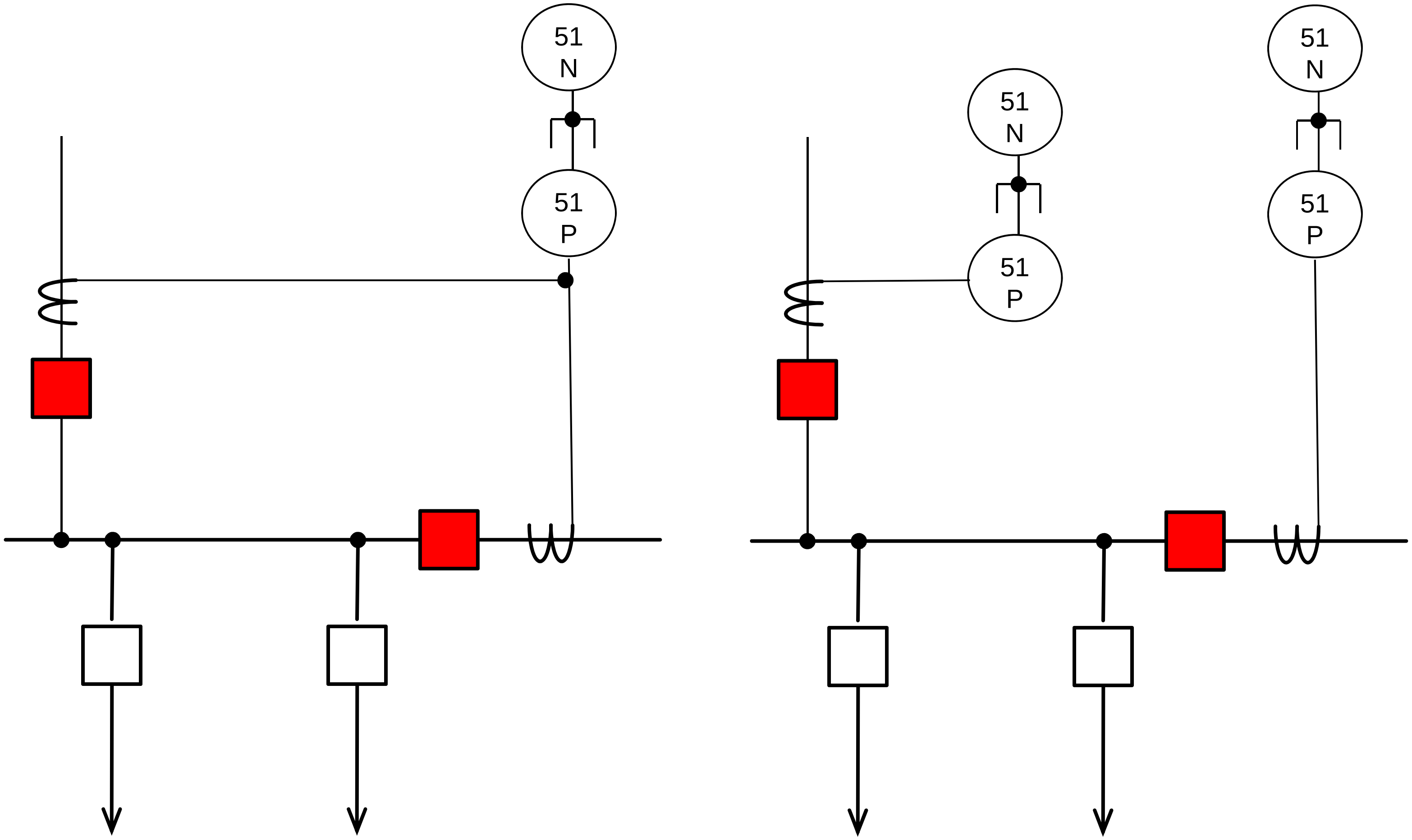
Secondary Selective Arrangement – N.O. Tie



Relaying not shown for clarity

Secondary Selective Arrangement – N.O. Tie

Why use “partial differential” or “bus overload”?



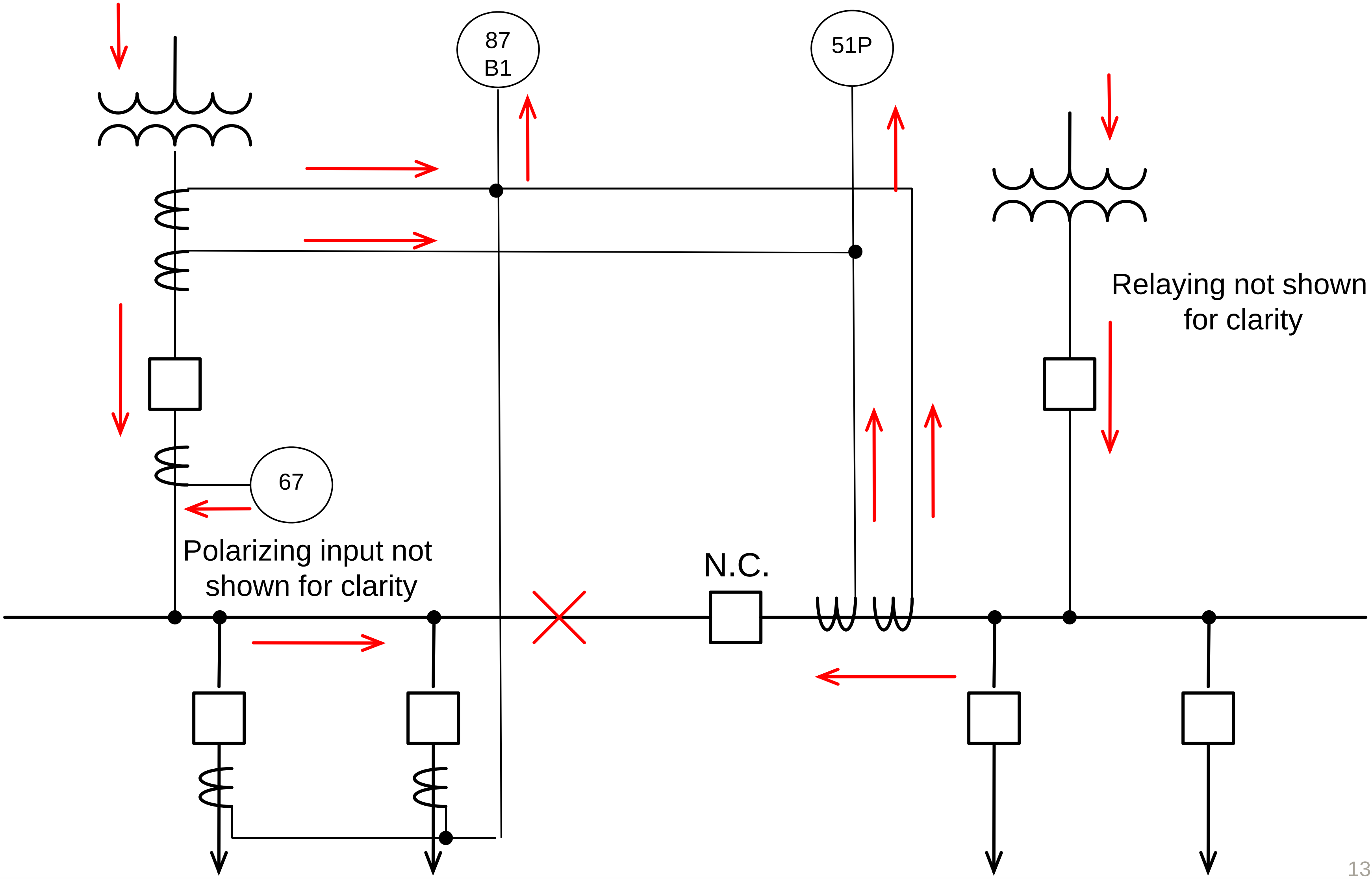
Secondary Selective Arrangement – N.O. Tie

Why use “partial differential” or “bus overload”?

Pros:
Use one (1) less relay
Eliminate one (1) level of coordination

Cons:
Require one (1) extra set of CTs on the tie breaker
Can not set 67 element on mains because currents are summed before the relay

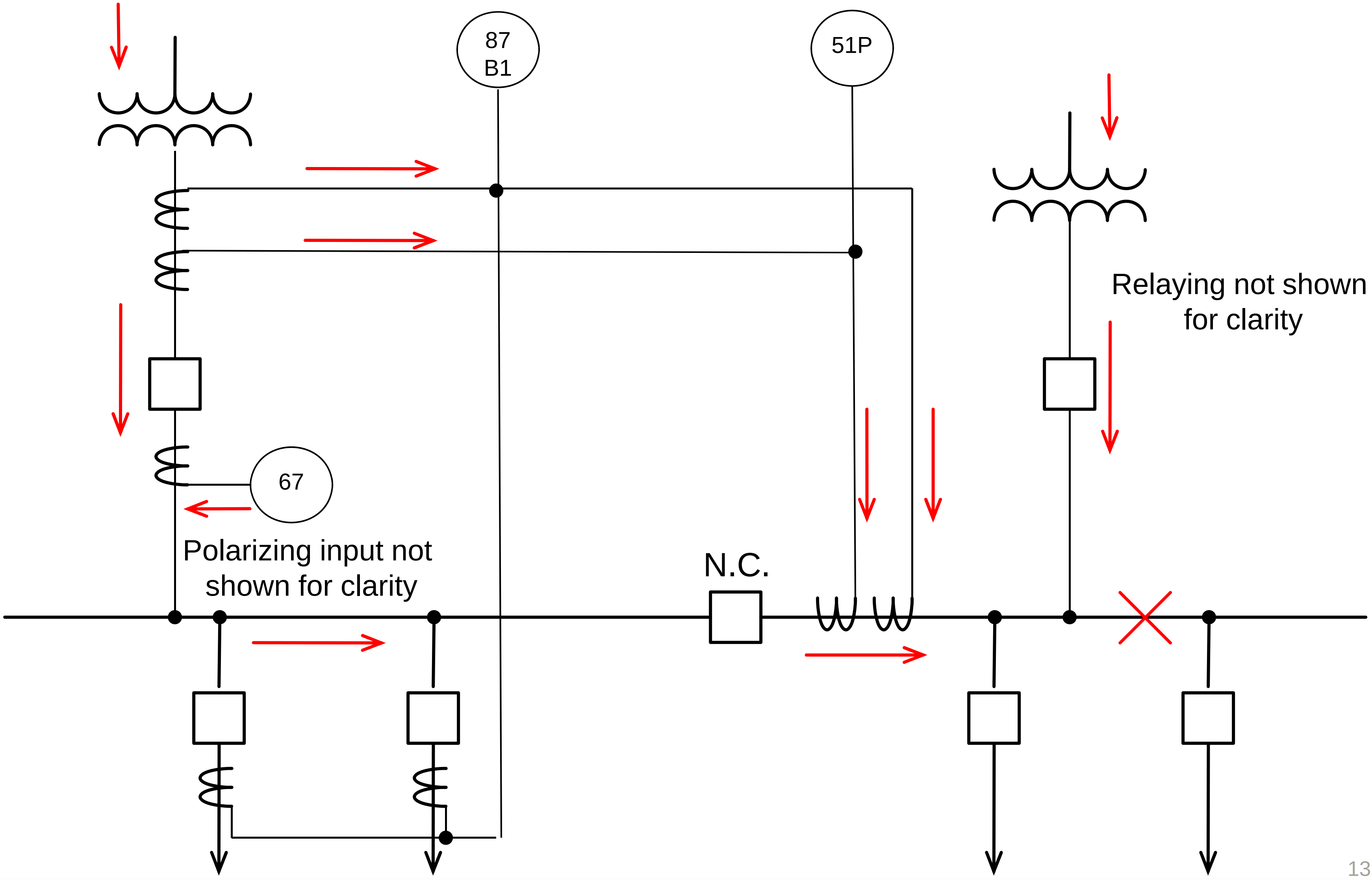
Secondary Selective Arrangement – N.C. Tie



Relaying not shown for clarity

Polarizing input not shown for clarity

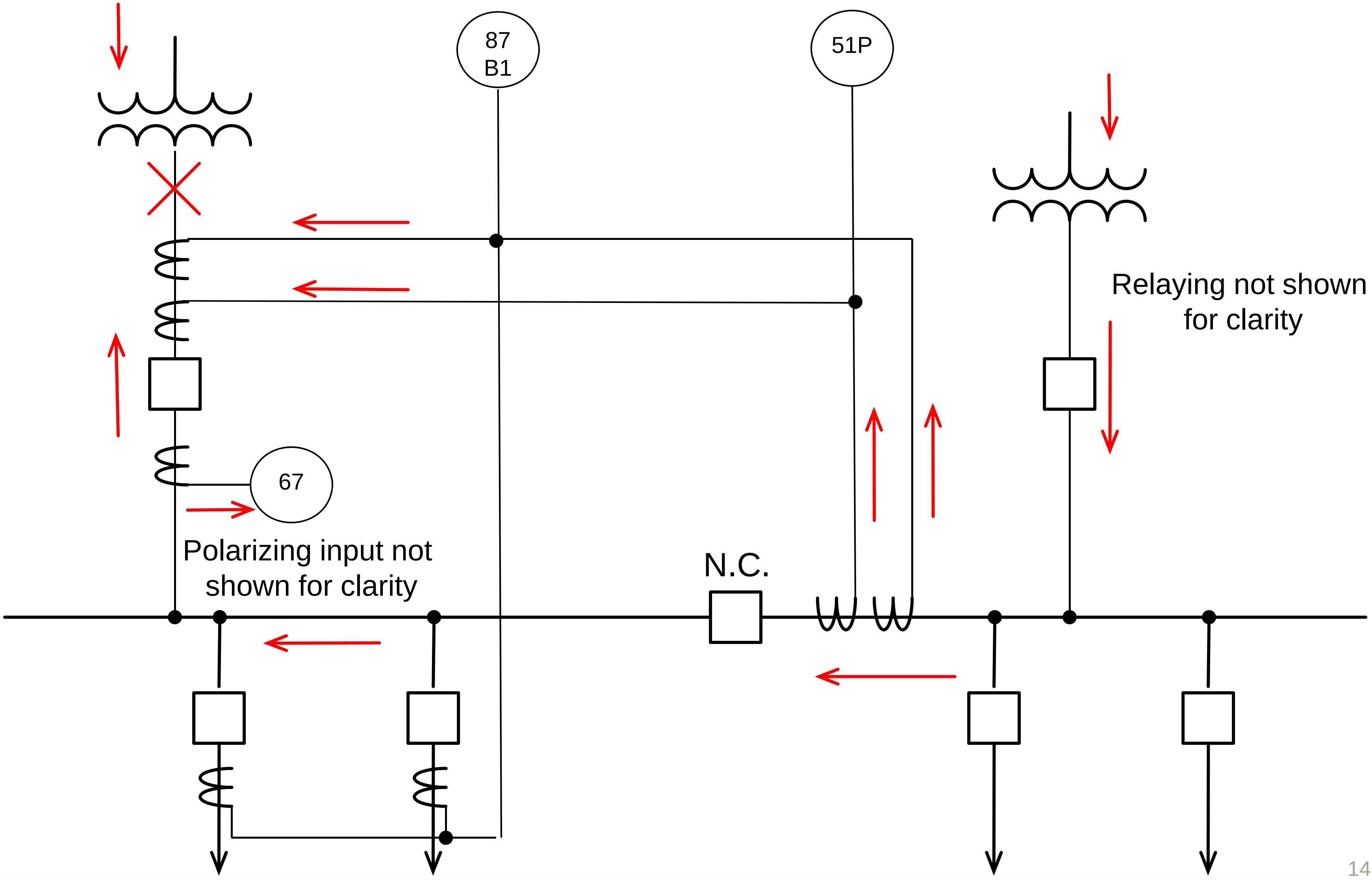
Secondary Selective Arrangement – N.C. Tie



Polarizing input not shown for clarity

Relaying not shown for clarity

Secondary Selective Arrangement – N.C. Tie



Relaying not shown for clarity

Polarizing input not shown for clarity

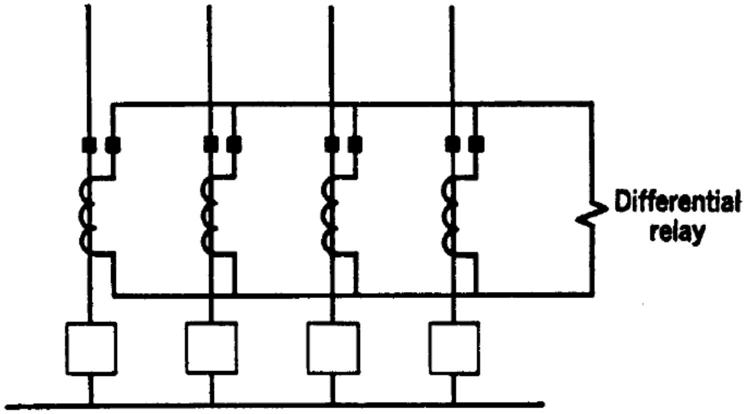
Bus Protection

- Differential Protection
  - Most sensitive and most reliable
  - Linear couplers – do not saturate (no iron core)
  - Multi-restraint differential – use restraint and variable percentage slopes to overcome iron core deficiencies at high currents
  - High impedance differential – forces false differentials through CTs and not relay

Bus Protection

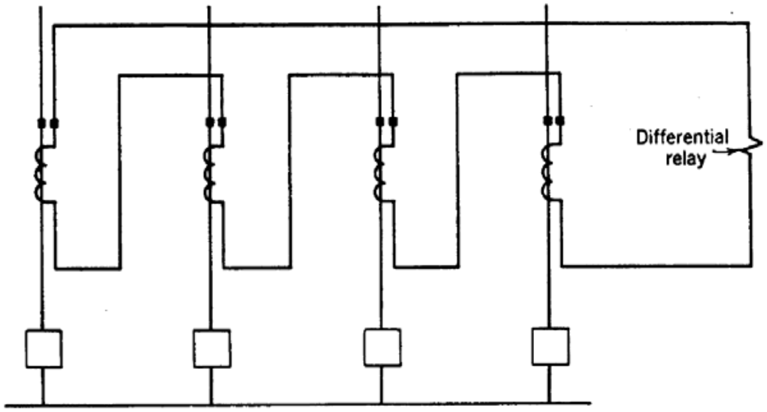
- Other Protection Methods
  - Instantaneous overcurrent
  - Low impedance overcurrent
    - Not recommended to use parallel CT connection
    - Relay cost is low, but engineering cost and application considerations is high
  - “Partial Differential”
    - Only sources are considered
  - Directional Comparison Blocking (Zone-Interlocking Schemes)
    - Feeders communicate with sources
    - Use caution with directional relays as directional unit may not operate properly on close-in hard three-phase faults

Bus Protection



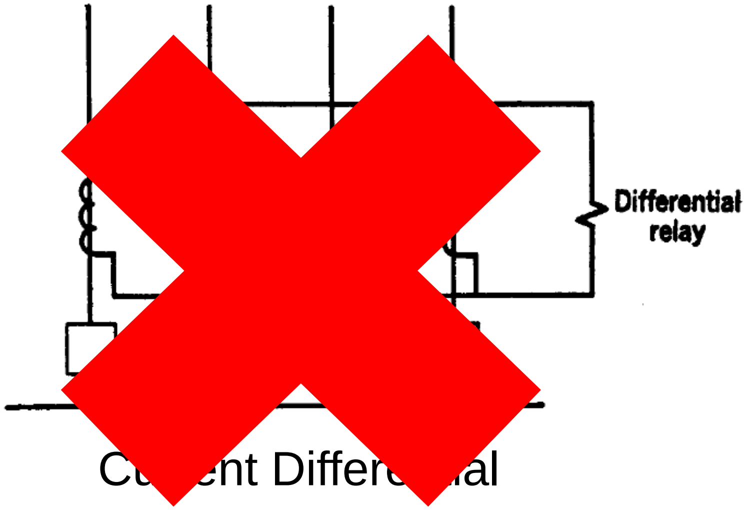
Current Differential

Not Recommended



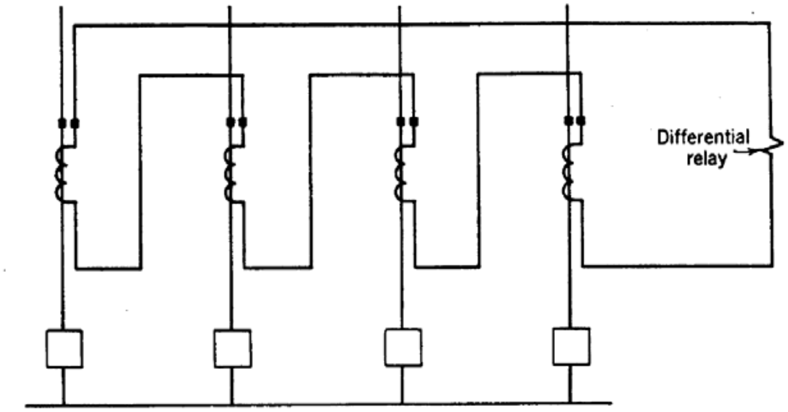
Voltage Differential – Using Linear Couplers

Bus Protection



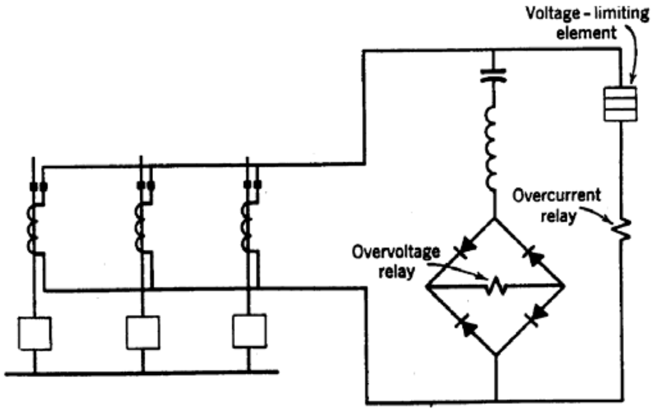
Cu[illegible]ent Differe[illegible]ial

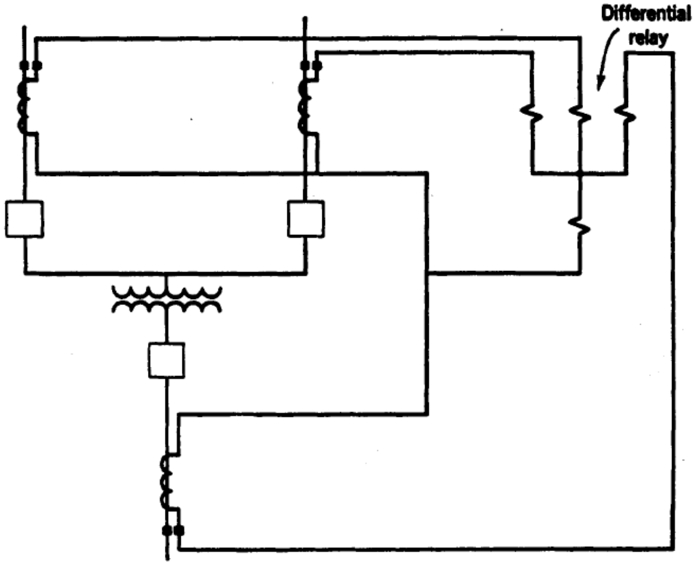
Not Recommended



Voltage Differential – Using Linear Couplers

Bus Protection





Current Differential with Restraint Elements

Current differential with restraint elements can be used for many applications (bus, transformer, generator, etc). The relay can account for different CT ratios (great for retrofit installations). However, since each CT has its own input, consider a 15 kV swgr application with 10 feeders per bus:

(10+Main + Tie) x 3 = 36 current inputs!

Voltage Differential using CTs

Main draw back is the inability to share the CT with different circuits.

Transformer Protection

- Considerations
  - Differential Protection
    - Different Voltage Levels Including Taps
    - Mismatch Due to CT Ratios
    - 30° Phase Shift on Delta-Wye Connections
    - Magnetizing Inrush
  - Overcurrent Protection
    - CT Performance During High-Current Faults
  - Transformer Type
    - Delta-Wye
    - Zig-Zag Grounding Transformer
    - Autotransformer with Delta Tertiary
    - Phase-Shifting Transformer

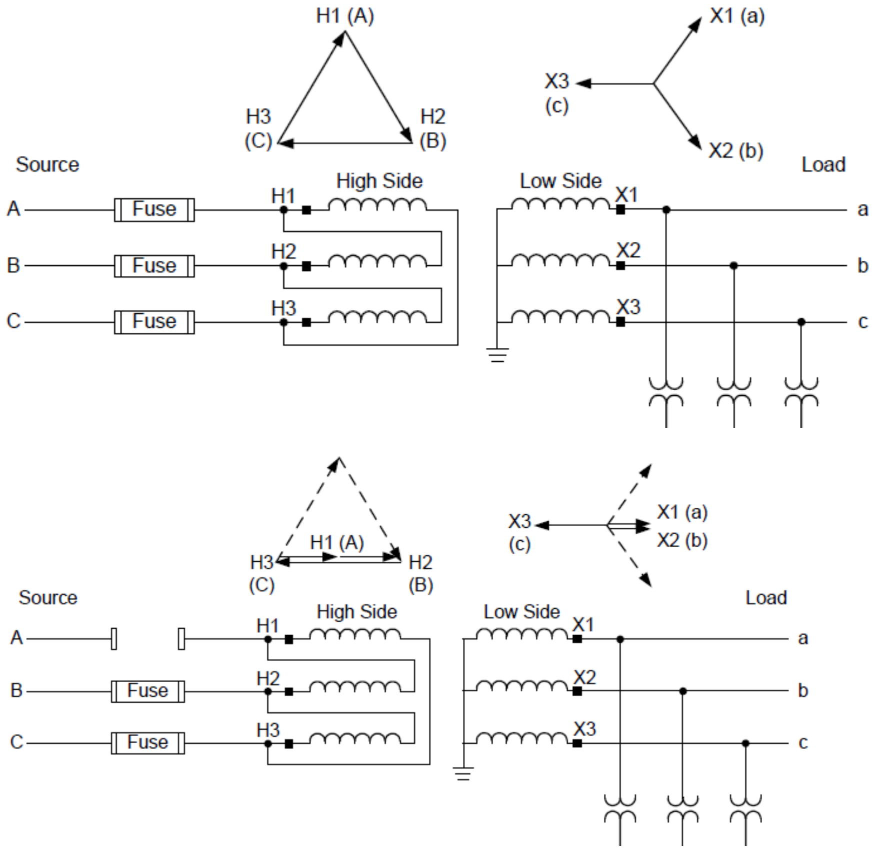
- IEEE Std C37.91 – IEEE Guide for Protective Relay Applications to Power Transformers

Motor Protection

- Low-Voltage Protection
  - Time-delayed undervoltage (27)
- Phase Rotation/Reversal Protection
  - Not typically necessary
- Negative Sequence Overvoltage Protection (47)
  - Time-delayed depending on amount of V_2
- Phase Unbalance/Negative Sequence Overcurrent (46)
  - Select curve below $(I_2)^2t$ = k damage curve
  - k = 40 generally considered conservative value
- Out-of-Step Protection/Loss of Excitation
  - Power Factor Sensing (55)
  - Distance Relay

Motor Protection

<u>Source:</u>
Schweitzer
SEL651A
Application
Guide



SV42 := (27YAB1 OR 27YBC1 OR 27YCA1) AND (59YAB1 OR 59YBC1 OR 59YCA1). The selected spare SELOGIC control equation variable combines any phase-to-phase undervoltage and any phase-to-phase overvoltage to detect a high-side blown fuse/open-phase condition.

Motor Protection

- Abnormal Conditions
  - Faults in Windings
  - Excessive Overloads
  - Reduction or Loss of Supply Voltage
  - Phase Reversal
  - Phase Unbalance
  - Out-of-step Operation (Synchronous Machines)
  - Loss of Excitation (Synchronous Machines)

Motor Protection

- Phase Fault Protection
    - Differential
    - Core Balance CT
    - Instantaneous Overcurrent
- Ground Fault Protection
    - Zero Sequence CT
- Locked Rotor Protection
    - Time Overcurrent – Set below rotor damage curve
    - Distance Relay (Large Machines)
- Overload Protection
    - Time overcurrent – Set below stator damage curve
- Thermal Protection – RTDs

Primary & Back-up Protection

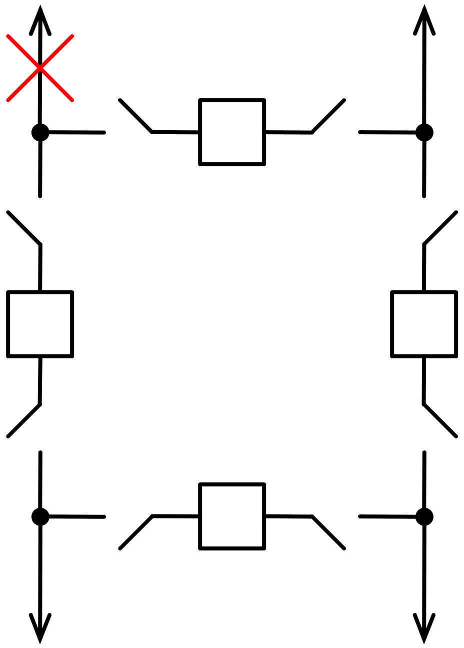
- Primary/Back-up Protection Philosophy
  - Each protected component has two sets of protection
  - Each protection set is independent of the other
  - Failure of any one component must not compromise protection
- DC Battery Systems
  - Single Battery System
    - Primary protection on different circuit from back-up protection
    - Blown fuse or open DC panel breaker cannot compromise protection
    - Battery itself is a single point of failure
  - Dual Battery System
    - Primary protection on different battery than back-up
    - Battery is no longer single point of failure

Breaker Failure Protection

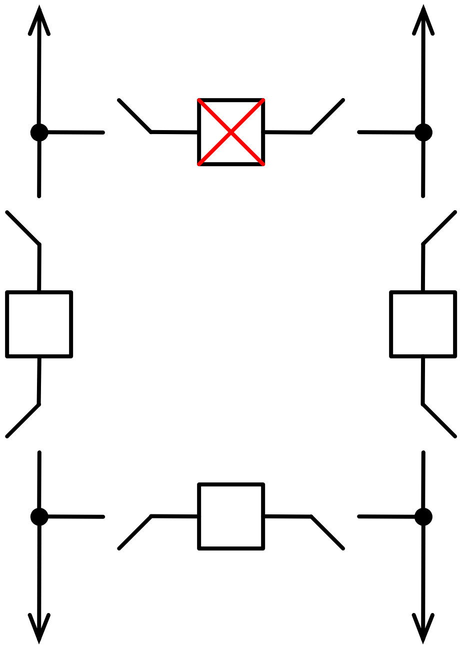
- More common at high voltage
- Communication assisted tripping required for line breakers (i.e. direct transfer trip)
- Typical Protection Logic
    - Trip signal received by breaker
    - Identical signal starts breaker failure timing
    - After a pre-set amount of time (6 cycles is common) and if current is still present in the breaker, then the breaker has failed
    - Trip zones on either side of the breaker
    - Dedicated lockout relay used for tripping, transfer tripping, fault recording, annunciation, and alarm

Breaker Failure Protection

Line/Bus Fault



Failed Breaker



Some considerations for protective relay applications…

Recommended References:

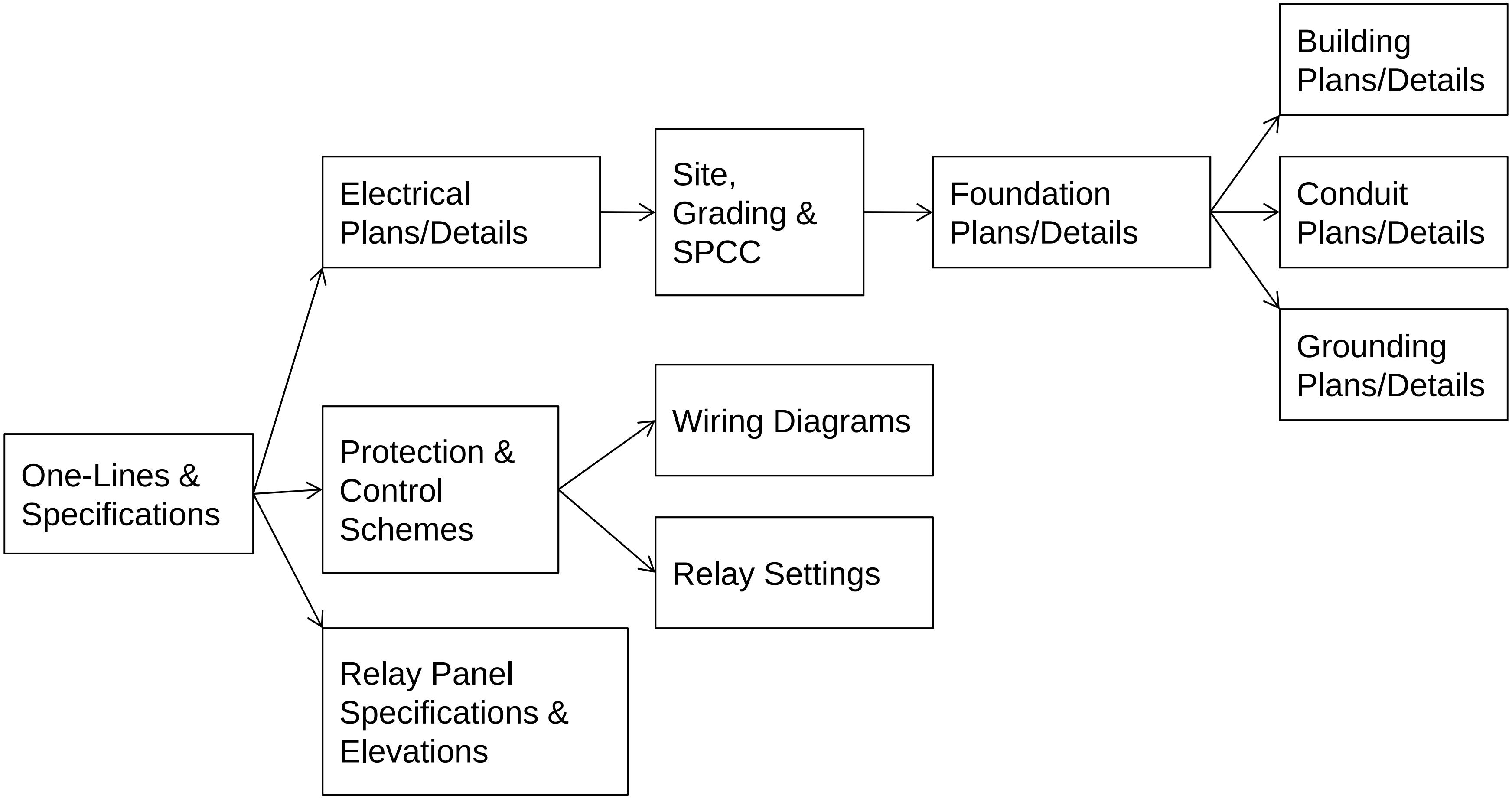
IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus – IEEE C37.90
Transformer Protection – IEEE Std C37.91
Motor Protection – IEEE C37.96
Bus Protection – IEEE C37.97 (withdrawn)
Shunt Capacitor Bank Protection – IEEE C37.99
Generator Protection – IEEE C37.102
Automatic Reclosing of Line Circuit Breakers for AC Distribution and Transmission Lines - IEEE Std C37.104
Shunt Reactor Protecction - ANSI/IEEE Std C37.109
Transmission Line Protection – IEEE C37.113
Breaker Failure Protection of Power Circuit Breakers – IEEE C37.119
IEEE Buff Book
IEEE Brown Book
Applied Protective Relaying - Westinghouse

Other Considerations

- Redundant DC power sources
- SER and DFR (oscillography) default settings enable only basic functionality at best case. Default settings by some manufacturers disable the SER and DFR.
- Synchronization of clocks
- Integration of protective relays with other IEDs
- Utilize outputs from “non-intelligent” devices as inputs to IEDs
- Don’t forget about test switches!!!

Engineering & Construction Coordination

Engineering Process


One-Lines & Specifications

Electrical Plans/Details

Protection & Control Schemes

Relay Panel Specifications & Elevations

Site, Grading & SPCC

Wiring Diagrams

Relay Settings

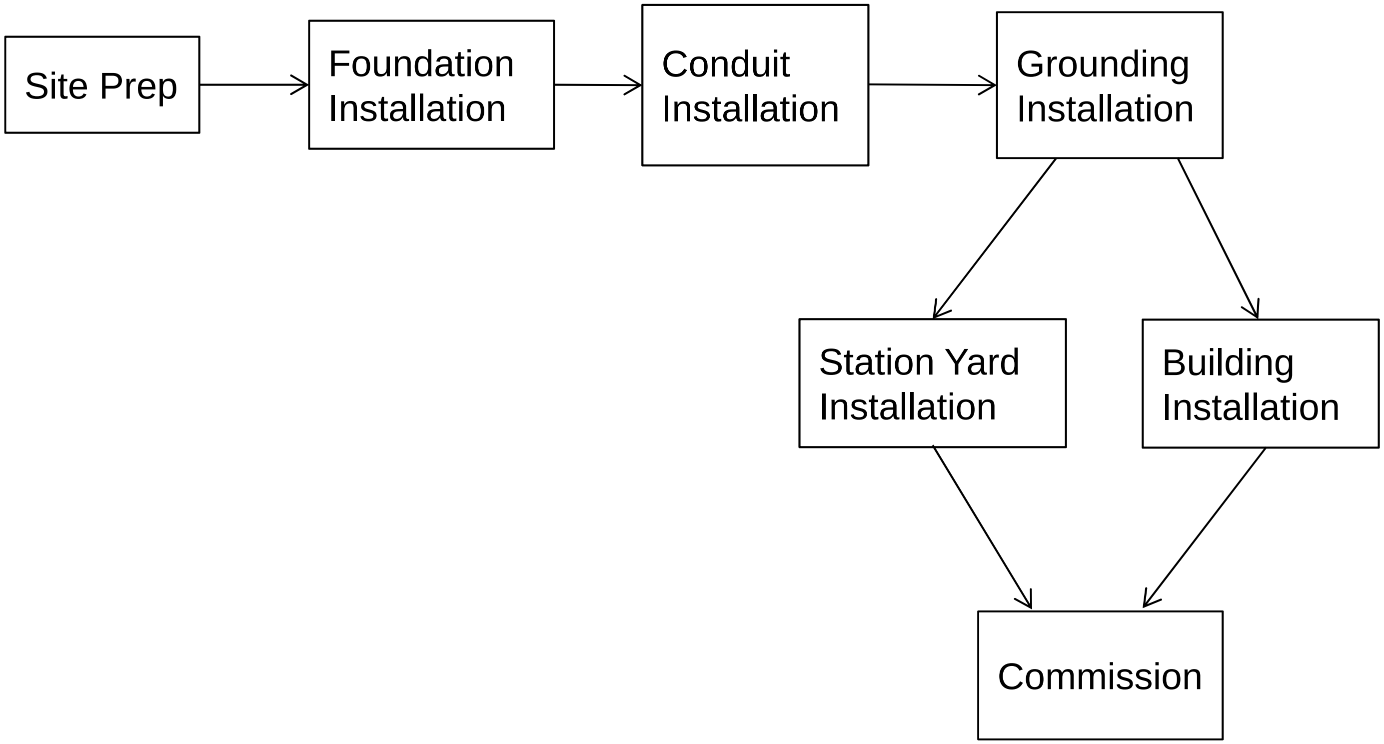
Foundation Plans/Details

Building Plans/Details

Conduit Plans/Details

Grounding Plans/Details

Construction Process


Site Prep

Foundation Installation

Conduit Installation

Grounding Installation

Station Yard Installation

Building Installation

Commission

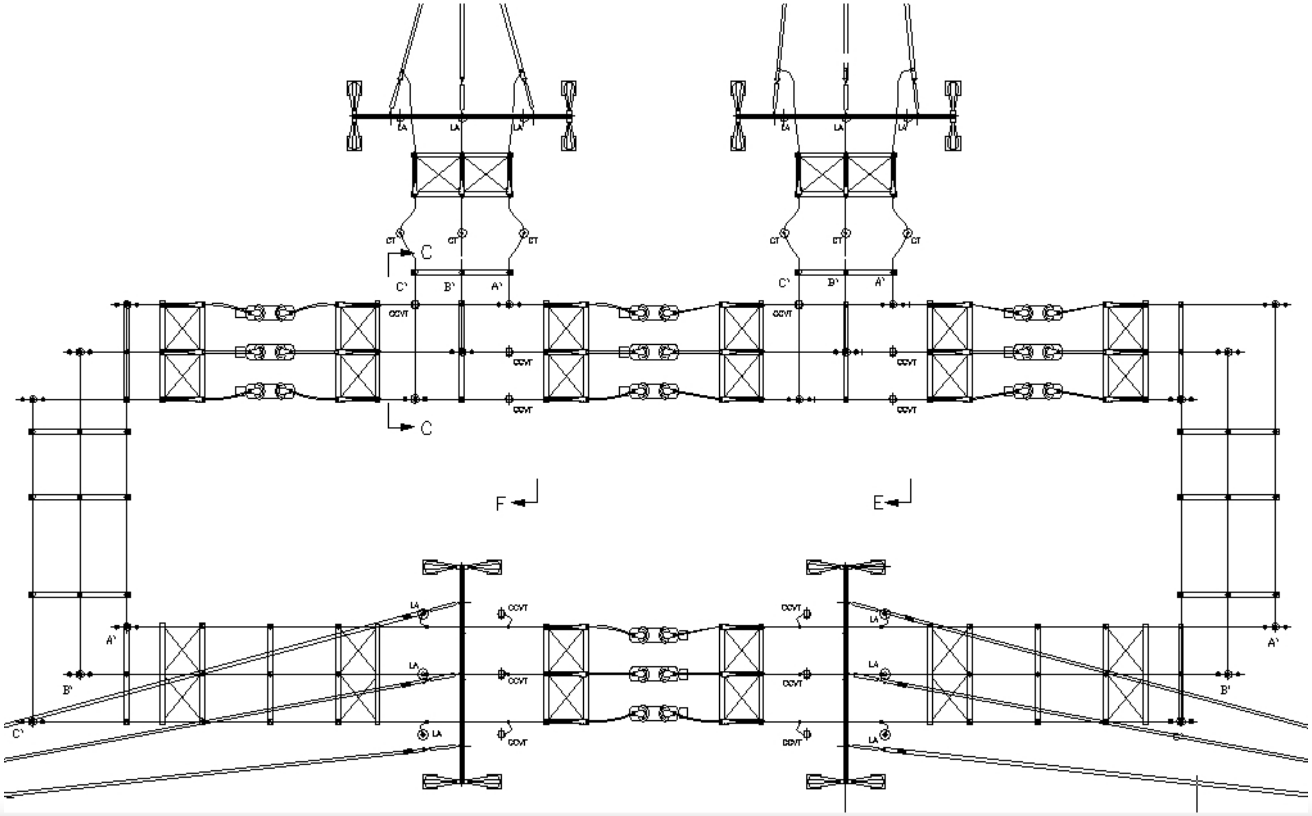
Supplemental Topics

Future Expansion Possibilities

- Tap to Ring
  - Build as “Loop Tap”
  - Add switches to facilitate expansion
  - Initial layout considerate of final ring bus configuration

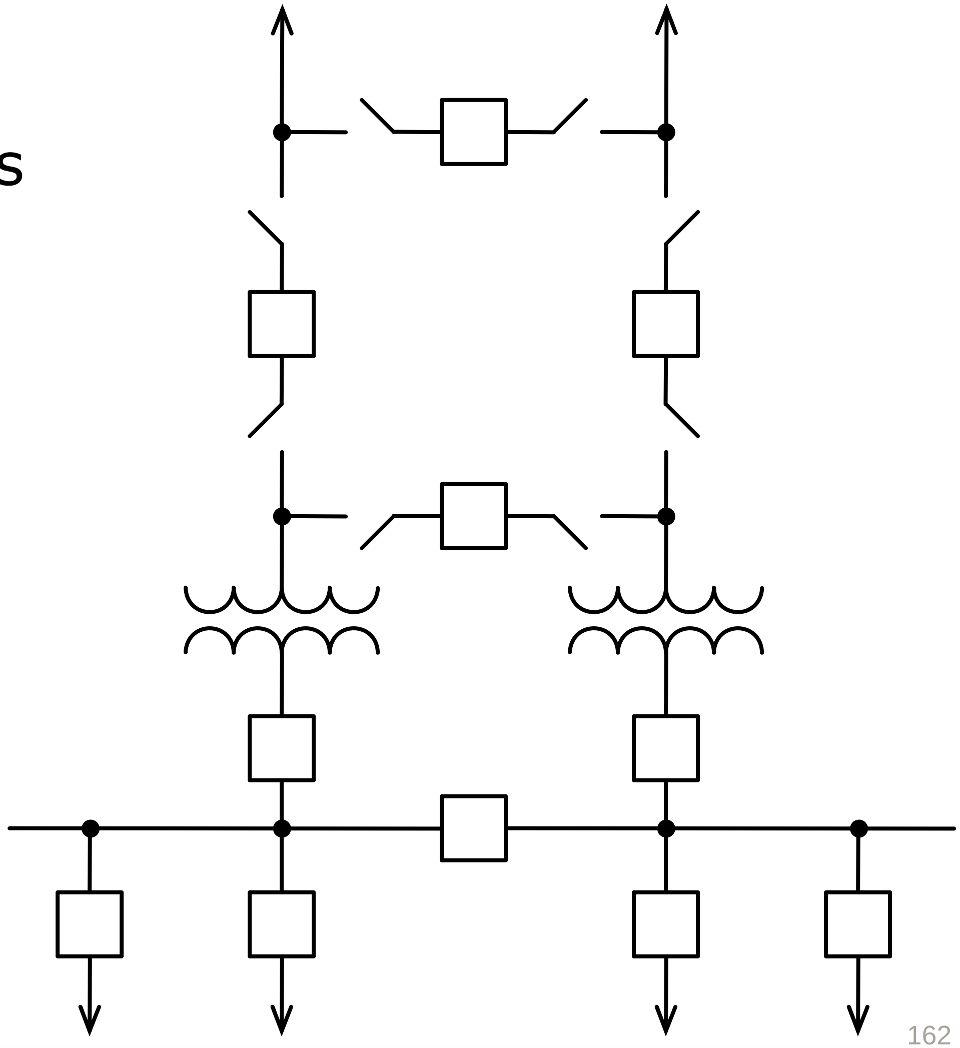
Future Expansion Possibilities

- Ring to Breaker-And-A-Half
  - Build as elongated ring bus
  - Allows future bay installations (i.e. additional circuits, two per bay



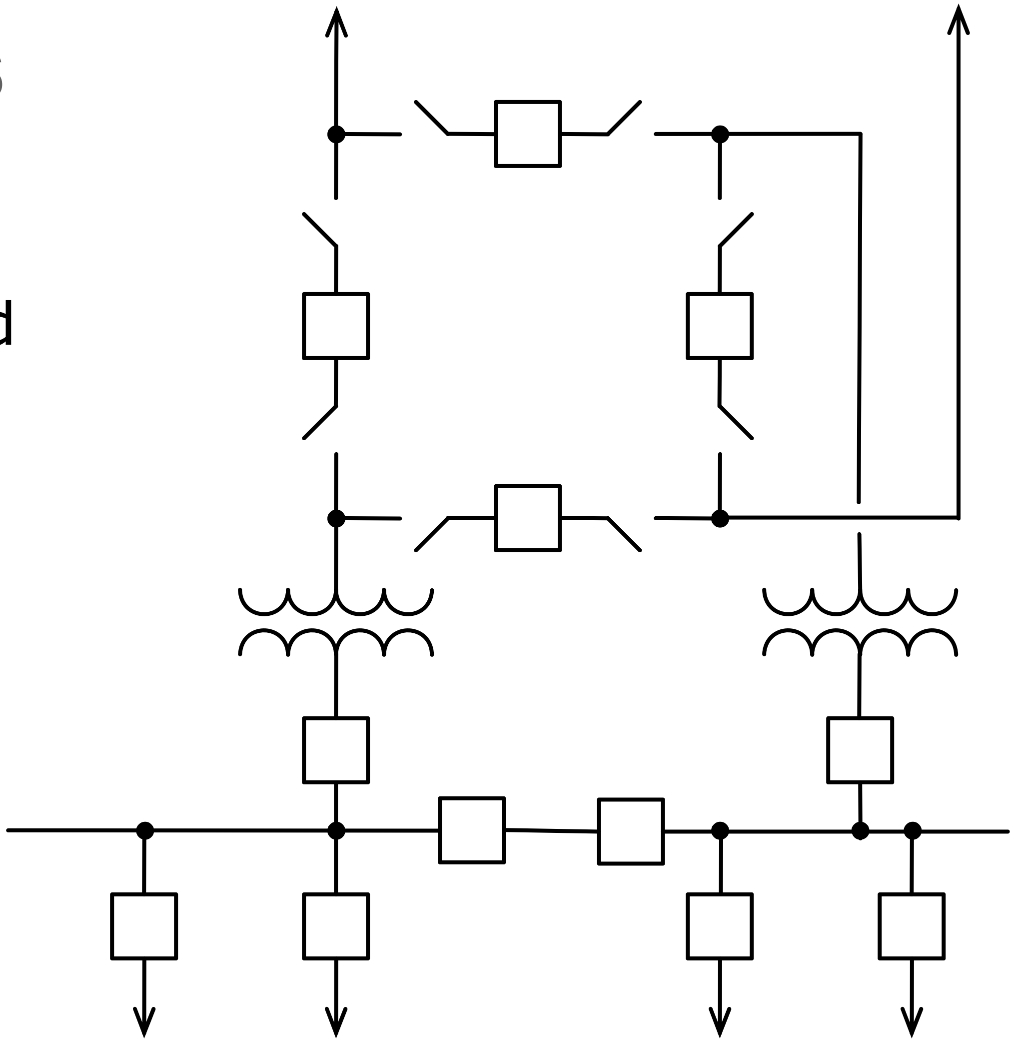
Mixing Bus Arrangements

- Example: Industrial
  - High-Voltage Ring Bus
  - Two Single Breaker Single Bus Medium-Voltage Systems with Tie Breaker (a.k.a. Secondary Selective)



Variations

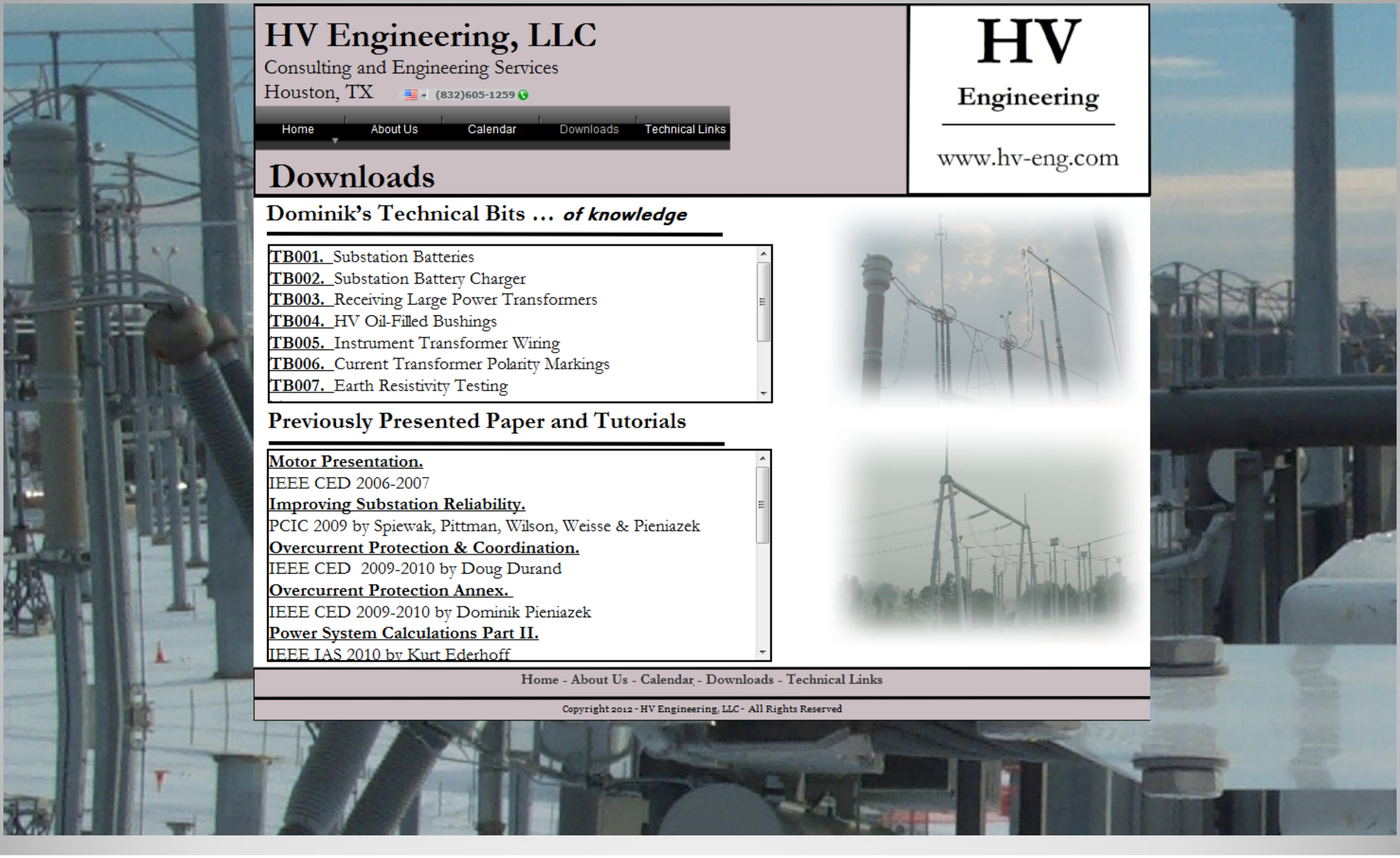
- Variations Exist
  - Swap Line and Transformer Positions
  - Add 2nd Tie Breaker



- Single Breaker Designs
  - Breaker maintenance requires circuit outage
  - Typically contain multiple single points of failure
  - Little or no operating flexibility
- Multiple Breaker Designs
  - Breaker maintenance does not require circuit outage
  - Some designs contain no single points of failure
  - Flexible operation
  - In general, highly adaptable and expandable

Conclusion

Questions?



HV Engineering, LLC
Consulting and Engineering Services
Houston, TX (832)605-1259

HV
Engineering
www.hv-eng.com

Downloads

Dominik's Technical Bits … *of knowledge*

TB001. Substation Batteries
TB002. Substation Battery Charger
TB003. Receiving Large Power Transformers
TB004. HV Oil-Filled Bushings
TB005. Instrument Transformer Wiring
TB006. Current Transformer Polarity Markings
TB007. Earth Resistivity Testing

Previously Presented Paper and Tutorials

Motor Presentation.
IEEE CED 2006-2007
Improving Substation Reliability.
PCIC 2009 by Spiewak, Pittman, Wilson, Weisse & Pieniazek
Overcurrent Protection & Coordination.
IEEE CED 2009-2010 by Doug Durand
Overcurrent Protection Annex.
IEEE CED 2009-2010 by Dominik Pieniazek
Power System Calculations Part II.
IEEE IAS 2010 by Kurt Ederhoff

Home - About Us - Calendar - Downloads - Technical Links

www.hv-eng.com

Appendix

www.hv-eng.com

Example of low profile substation using lattice structures

Example of conventional design

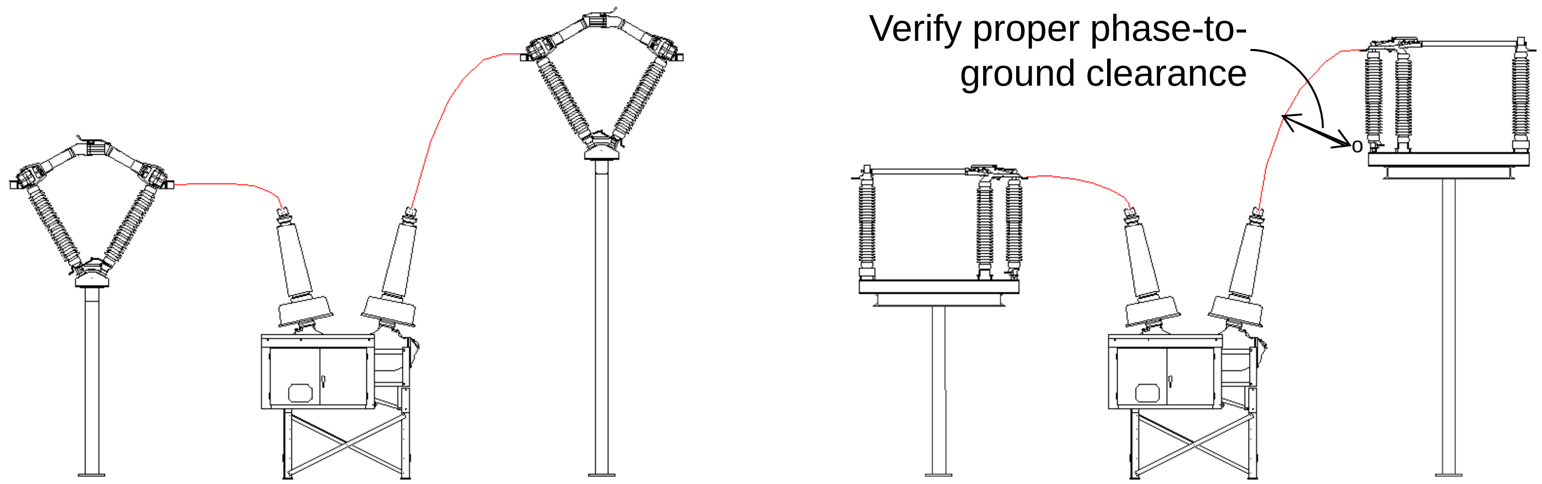
Base plates with grout

Installation leads to rusting at base of support

Base plates without grout

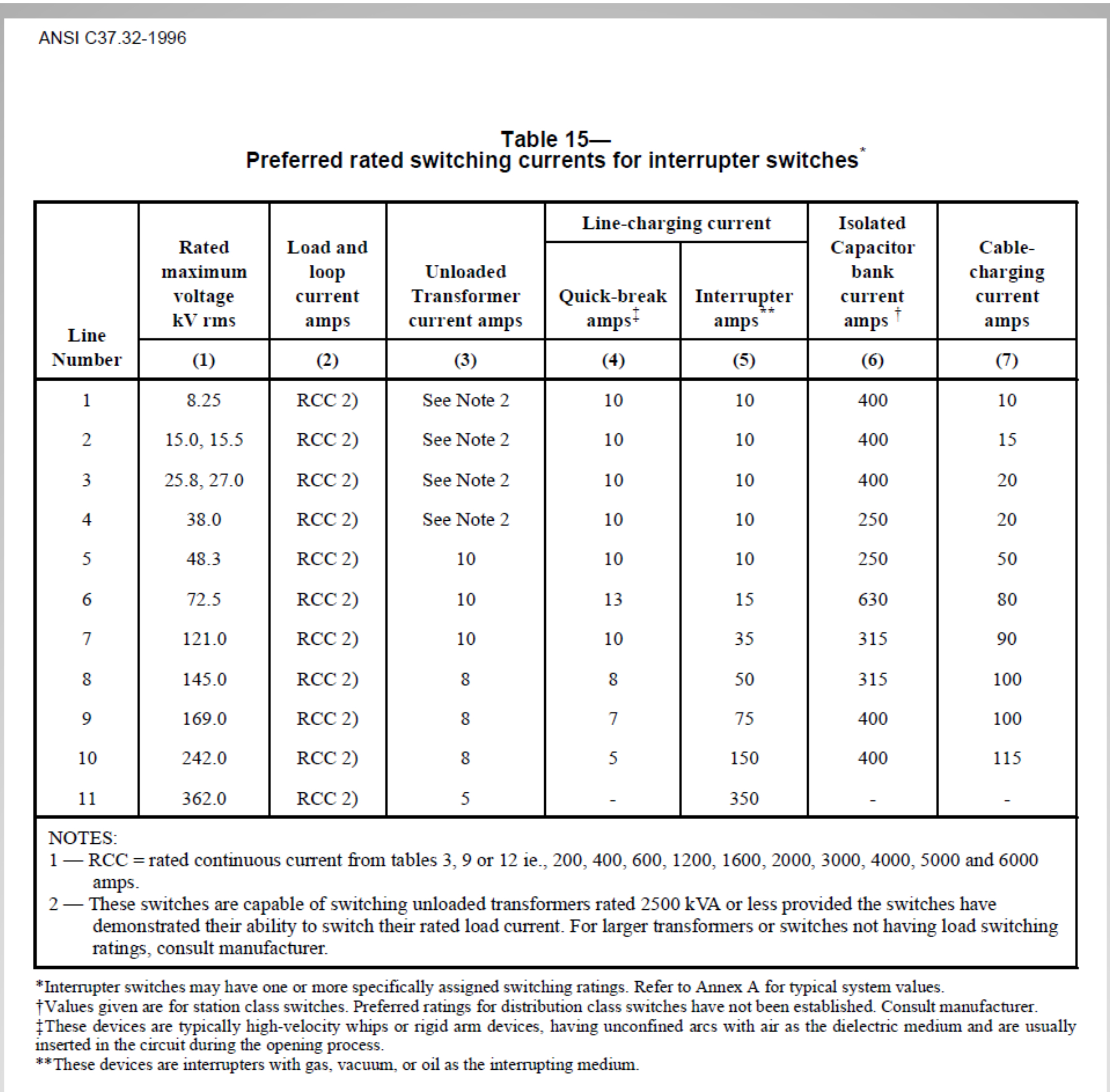
Preferred Installation Method*

* Structural engineer should confirm base plate and anchor bolts are sized properly



Verify proper phase-to-ground clearance

Vee Break vs. Vertical Break



ANSI C37.32-1996

Table 15—
Preferred rated switching currents for interrupter switches[*]

Line Number	Rated maximum voltage kV rms	Load and loop current amps	Unloaded Transformer current amps	Line-charging current		Isolated Capacitor bank current amps [†]	Cable-charging current amps
				Quick-break amps[‡]	Interrupter amps[**]		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	8.25	RCC 2)	See Note 2	10	10	400	10
2	15.0, 15.5	RCC 2)	See Note 2	10	10	400	15
3	25.8, 27.0	RCC 2)	See Note 2	10	10	400	20
4	38.0	RCC 2)	See Note 2	10	10	250	20
5	48.3	RCC 2)	10	10	10	250	50
6	72.5	RCC 2)	10	13	15	630	80
7	121.0	RCC 2)	10	10	35	315	90
8	145.0	RCC 2)	8	8	50	315	100
9	169.0	RCC 2)	8	7	75	400	100
10	242.0	RCC 2)	8	5	150	400	115
11	362.0	RCC 2)	5	-	350	-	-

NOTES:

1 — RCC = rated continuous current from tables 3, 9 or 12 ie., 200, 400, 600, 1200, 1600, 2000, 3000, 4000, 5000 and 6000 amps.

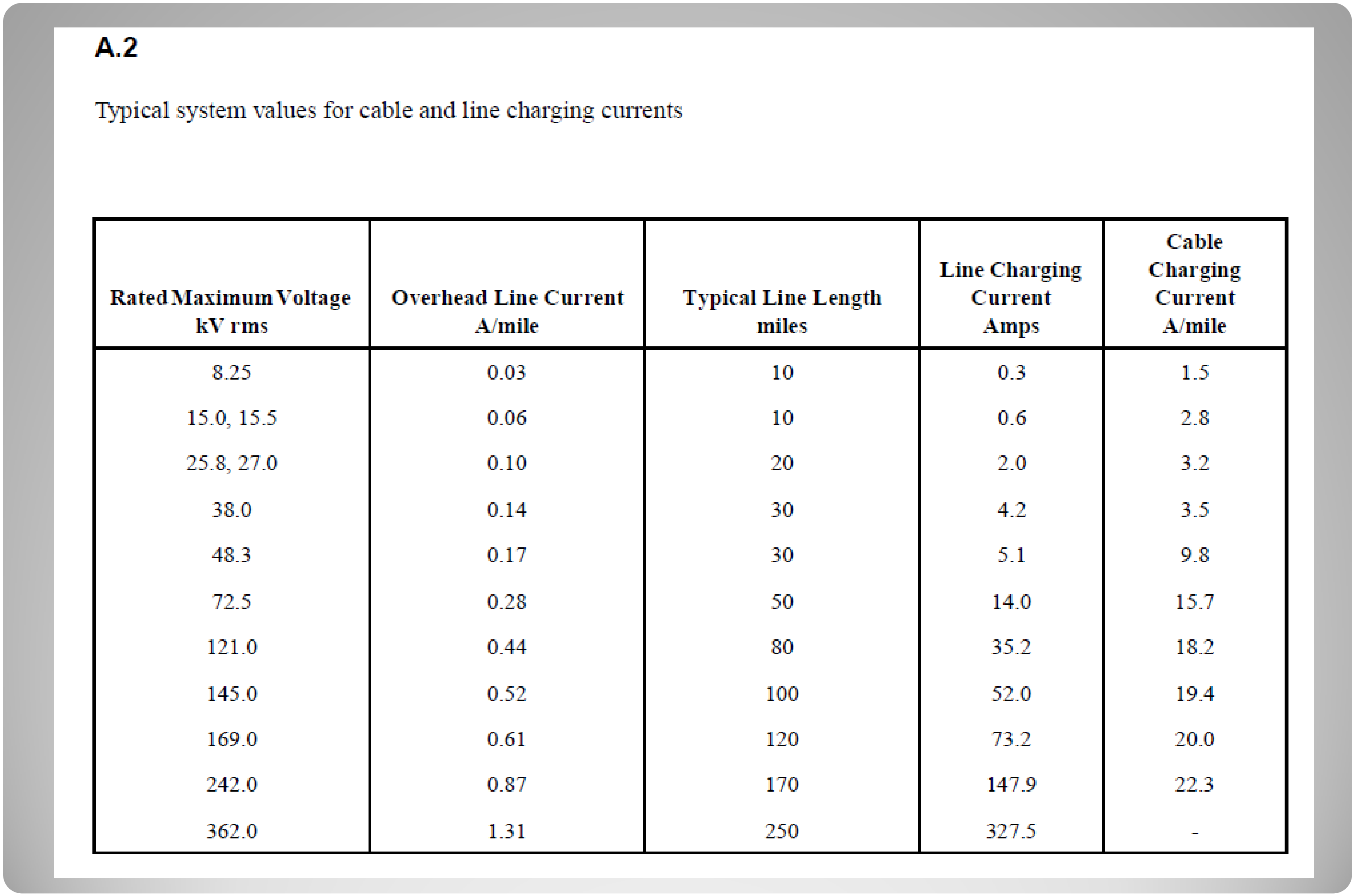
2 — These switches are capable of switching unloaded transformers rated 2500 kVA or less provided the switches have demonstrated their ability to switch their rated load current. For larger transformers or switches not having load switching ratings, consult manufacturer.

[*] Interrupter switches may have one or more specifically assigned switching ratings. Refer to Annex A for typical system values.

[†] Values given are for station class switches. Preferred ratings for distribution class switches have not been established. Consult manufacturer.

[‡] These devices are typically high-velocity whips or rigid arm devices, having unconfined arcs with air as the dielectric medium and are usually inserted in the circuit during the opening process.

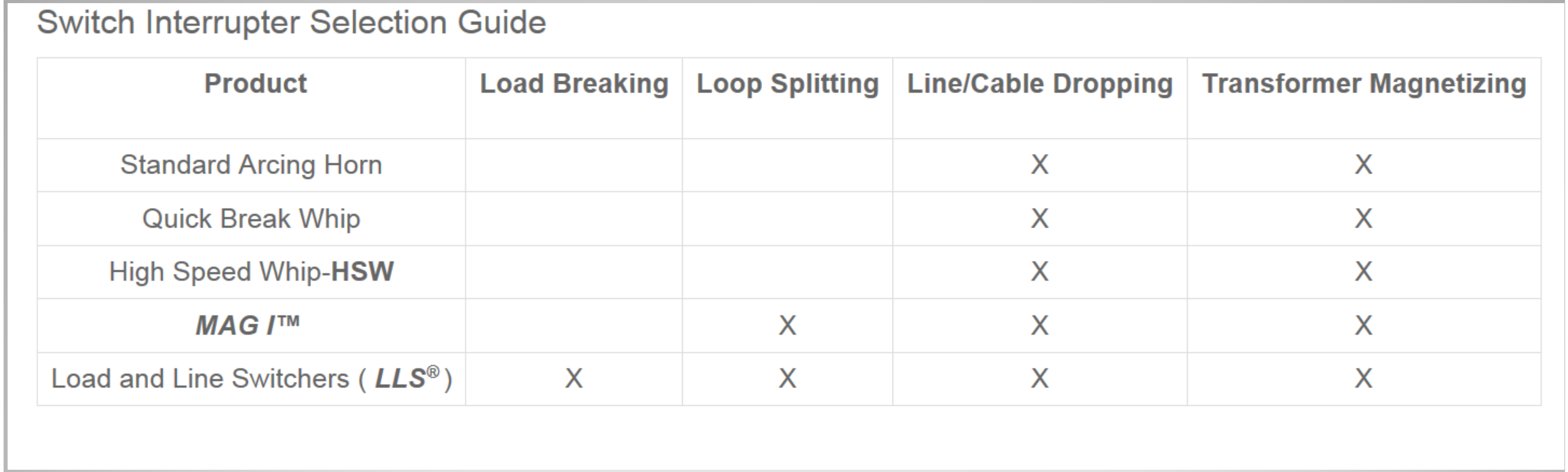
[**] These devices are interrupters with gas, vacuum, or oil as the interrupting medium.



A.2

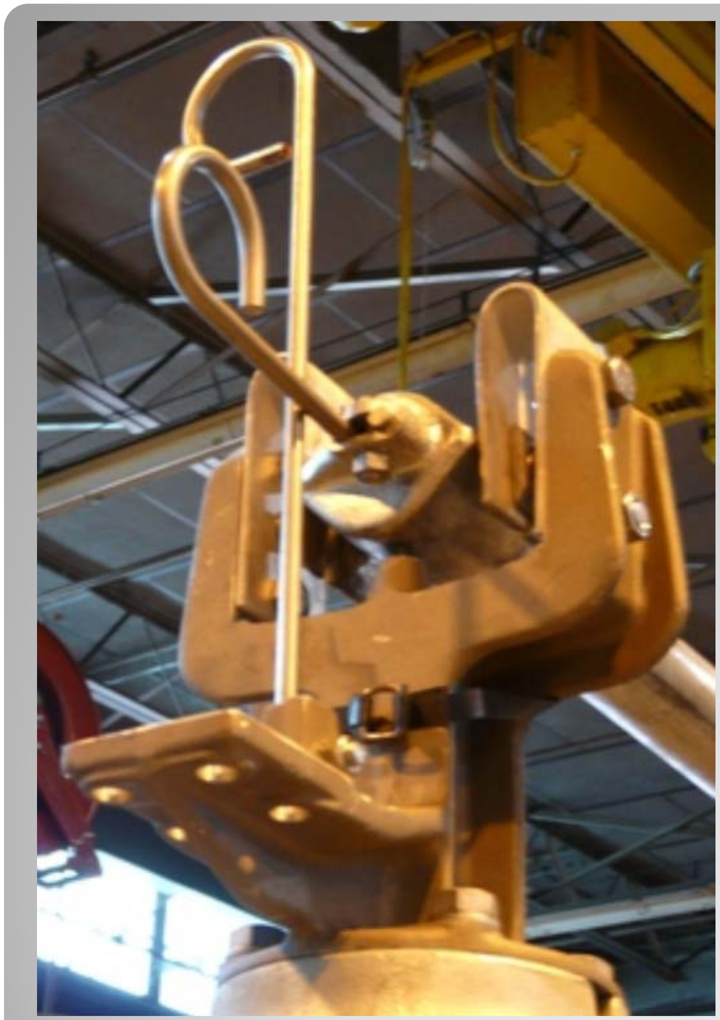
Typical system values for cable and line charging currents

Rated Maximum Voltage kV rms	Overhead Line Current A/mile	Typical Line Length miles	Line Charging Current Amps	Cable Charging Current A/mile
8.25	0.03	10	0.3	1.5
15.0, 15.5	0.06	10	0.6	2.8
25.8, 27.0	0.10	20	2.0	3.2
38.0	0.14	30	4.2	3.5
48.3	0.17	30	5.1	9.8
72.5	0.28	50	14.0	15.7
121.0	0.44	80	35.2	18.2
145.0	0.52	100	52.0	19.4
169.0	0.61	120	73.2	20.0
242.0	0.87	170	147.9	22.3
362.0	1.31	250	327.5	-



Switch Interrupter Selection Guide

Product	**Load Breaking**	**Loop Splitting**	**Line/Cable Dropping**	**Transformer Magnetizing**
Standard Arcing Horn			X	X
Quick Break Whip			X	X
High Speed Whip-**HSW**			X	X
MAG I™		X	X	X
Load and Line Switchers (***LLS***®)	X	X	X	X



Arcing Horn

Quick Break Whip

High Speed Whip

Magnetic Interrupter

Load and Line Switcher