More Probable Contingency Assessment Criteria

SYSTEM PERFORMANCE GOALS

	ELEMENT LOST	NATURE OF DISTURBANCE	PREFAULT CONDITION	BEFORE ADJUSTMENT	AFTER ADJUSTMENT	COMMENTS
1.	Any single bus section, transformer, line, generator, reactive device, load.	30 fault. normal clearing, automatic reclosing if used.	Either normal, or with outage of any line, generator or transformer accompanied by adjusted operation.	All facility loadings within applicable emergency limits. All transmission voltages within emergency limits. Stability shall be maintained without interruption of load due to instability or cascading.	Within the time frame of the emergency ratings, all facility loadings should be within normal ratings. All transmission voltages within normal limits.	Criteria performance shall apply to all systems except the one on which the disturbance occurs. Reclosing is used, assume that is it unsuccessful.
2.	Double circuit line.	Simultaneous 1Ø-G faults on both circuits, normal clearning-automatic reclosing if used.	same as above	same as above	same as above	same as above
3.	Any item 1 above	Permanent 1Ø-G fault delayed clearing due to malfunction of breaker due to relay systems, or of signal channel, automatic reclosing if used.	same as above	same as above	same as above	same as above
4.	Bi-polar d. c. line	Simultaneous, permanent line-around faults on both poles. Due regard to automatic restart sequence if used.	same as above	same as above	same as above	same as above
5.	HVDC back-to-back convertor station	30 fault on either side of convertor within range to cause convertor to block. Due regard to automatic restart sequence if used.	Convertor loaded to maximum capacity with power flow in either direction.	same as above	same as above	same as above

More Probable Contingency Assessment Criteria

SYSTEM PERFORMANCE GOALS

	ELEMENT LOST	NATURE OF DISTURBANCE	PREFAULT CONDITION	BEFORE ADJUSTMENT	AFTER ADJUSTMENT	COMMENTS
6.	Any item in 1 above	No fault	same as above	same as above	same as above	same as above
7.	Any single critical generating unit.	Three phase fault with normal clearing	Normal scheduled outage(s)	All facility loadings within applicable emergency limits. All transmission voltages within emergency limits.	Within the time frame of the emergency ratings, all facility loadings should be within normal ratings. All transmission voltages within normal limits.	Criteria performance goal shall apply to all systems except the one on which the disturbance occurs. If reclosing is used, assume that it is unsuccessful.
8.	Any single critical transmission line.	same as above	same as above	same as above	same as above	same as above
9.	Any single transformer	same as above	same as above	same as above	same as above	same as above
10.	Any bus section	same as above	same as above	same as above	same as above	same as above
11.	Any double circuit line.	same as above	same as above	same as above	same as above	same as above
12.	Any combination of related facilities.	Failure of circuit breaker.	same as above	same as above	same as above	same as above
13.	Any element.	Any short circuit cleared by back-up relays	same as above	same as above	same as above	same as above
14.	Any element.	One phase fault with delayed clearing.	same as above	same as above	same as above	same as above

More Probable Contingency Assessment Criteria

SYSTEM PERFORMANCE GOALS

	ELEMENT LOST	NATURE OF DISTURBANCE	PREFAULT CONDITION	BEFORE ADJUSTMENT	AFTER ADJUSTMENT	COMMENTS
15.	Any single critical generating unit.	No fault.	Normal scheduled outage(s).	All facility loadings within applicable emergency limits. All transmission voltages within emergency limits.	Within the time frame of the emergency ratings, all facility loadings should be within normal ratings. All transmission voltages within normal limits.	Criteria performance goal shall apply to all systems except the one on which the disturbance occurs. If reclosing is used, assume that it is unsuccessful.
16.	Any single critical transmission line.	same as above	same as above	same as above	same as above	same as above
17.	Any single transformer.	same as above	same as above	same as above	same as above	same as above
18.	Any bus section	No fault	same as above	same as above	same as above	same as above
19.	Any double circuit line	same as above	same as above	same as above	same as above	same as above
20.	Any combination of related facilities	same as above	same as above	same as above	same as above	same as above
21.	Any single critical generating unit	Three phase fault with normal clearing	Loss of any critical generator, transmission line, transformer, bus section with subsequent system readjustment	same as above	same as above	same as above
22.	Any single critical transmission line.	same as above	same as above	same as above	same as above	same as above

More Probable Contingency Assessment Criteria

SYSTEM PERFORMANCE GOALS

	ELEMENT LOST	NATURE OF DISTURBANCE	PREFAULT CONDITION	BEFORE ADJUSTMENT	AFTER ADJUSTMENT	COMMENTS
23.	Any single transformer	same as above	same as above	same as above	same as above	same as above
24.	Any bus section	same as above	same as above	same as above	same as above	same as above
25.	Any double circuit line	same as above	same as above	same as above	same as above	same as above
26.	Any combination of related facilities	Failure of circuit breaker	same as above	same as above	same as above	same as above
27.	Any element	Any short circuit cleared by back-up relays	same as above	same as above	same as above	same as above
28.	Any element	One phase fault with delayed clearing	Loss of any critical generator, transmission line, transformer, bus section with subsequent system readjustment	All facility loadings within applicable emergency limits. All transmission voltages within emergency limits.	Within the time frame of the emergency ratings, all facility loadings should be within emergency limits. All the one on transmission voltages within normal limits.	Criteria performance goal shall apply to all systems except the one on which the disturbance occurs. If reclosing is used, assume that is unsuccessful.
29.	Any single critical generating unit.	No fault	same as above	same as above	same as above	same as above
30.	Any single critical transmission line	same as above	same as above	same as above	same as above	same as above
31.	Any single transformer	same as above	same as above	same as above	same as above	same as above

More Probable Contingency Assessment Criteria

SYSTEM PERFORMANCE GOALS

	ELEMENT LOST	NATURE OF DISTURBANCE	PREFAULT CONDITION	BEFORE ADJUSTMENT	AFTER ADJUSTMENT	COMMENTS
32.	Any bus section	same as above	same as above	same as above	same as above	same as above
33.	Any double circuit line	same as above	same as above	same as above	same as above	same as above
34.	Any combination of related facilities	same as above	same as above	same as above	same as above	same as above

Uniform Rating of Generating Equipment
DETERMINATION OF AMBIENT RATING CONDITIONS

1.0 PURPOSE

The purpose of this appendix is to facilitate the determination standard rating conditions for specific generating locations. Criteria 12.1.5.2 describes rating conditions for which these steps apply.

2.0 PROCEDURE FOR INTERPOLATION OF TEMPERATURE DATA

2.1 Obtain the latitude, longitude, and elevation of the plant site.

2.2 Determine the location of the nearest weather station from the ASHRAE Handbook. If the station is within 30 miles of the plant site, then the plant weather conditions can be assumed the same as this station. If this is the case, then skip Steps 2.3 through 2.5.

2.3 Determine the location of the three nearest weather stations listed in the ASHRAE Handbook which form a triangle around the plant location.

2.4 Correct the dry-bulb and wet-bulb temperatures at points A, B, and C (weather stations) to the plant's elevation using the following rules:

2.4.1 Dry-bulb temperature decreases approximately 1 °F per 200 feet increase in elevation.

2.4.2 Wet-bulb temperature decreases approximately 1 °F per 500 feet increase in elevation.

2.5 Determine the dry-bulb and wet-bulb temperatures at plant P, by taking the weighted mean average between corrected temperatures at points A, B, and C, where:

$$T = (T_A D_{PA} + T_B D_{PB} + T_C D_{PC})/(D_{PA} + D_{PB} + D_{PC})$$

and

$$D_{PA} = ((y_P - y_A)^2 + (x_P - x_A)^2)^{½}$$
$$D_{PB} = ((y_P - y_B)^2 + (x_P - x_B)^2)^{½}$$
$$D_{PC} = ((y_P - y_C)^2 + (x_P - x_C)^2)^{½}$$

Note that each minute (1/60th of a degree) of latitude (north/south direction) is one nautical mile. Because lines of longitude converge toward the poles, nautical miles in the east/west direction may be approximated by multiplying the minutes of longitude by the cosine of the plant's angle of latitude. See the example in Section 4.0.

3.0 DETERMINATION OF BAROMETRIC PRESSURE

To determine the standard barometric pressure for the plant elevation, use the following formula:

$$P_{SB} = 29.921 \times (1 - 6.8753 \times 0.000001 \times \text{Elevation})^{5.2559}$$

See the example in Section 4.0.

4.0 EXAMPLE

Given: Plant site is 39°, 15‘ latitude; 94°, 58’ longitude.
Elevation is 750 feet.

Find: Generator rating conditions.

1. Determine the three nearest weather stations and temperatures from the ASHRAE Handbook.

Station	Latitude	Longitude	Elevation	T_d	T_w
Kansas City, MO	39°, 07’	94°, 35’	791	99	75
Atchison, KS	39°, 34’	95°, 07’	945	96	77
Topeka, KS	39°, 04’	95°, 38’	877	99	75

2. Correct the temperatures to the plant elevation.

Station	Elevation above Plant	Effect on T_d	Effect on T_w	Corrected T_d	Corrected T_w
Kansas City, MO	41	+0.2	+0.1	99.2	75.1
Atchison, KS	195	+1.0	+0.4	97.0	77.4
Topeka, KS	127	+0.6	+0.3	99.6	75.3

3. Using 39°, 00’; 94°, 00’ as the origin determine the relative location of each point A, B, and C from the plant P. To obtain the east-west dimensions, multiply the longitude minutes from 94°, 00’ by the cosine of plant latitude; cos (39.25) = 0.7744. Doing so, the following coordinates are obtained:

Station	North	West	Point
Plant	15	44.9	P
Kansas City, MO	07	27.1	A
Atchison, KS	34	51.9	B
Topeka, KS	04	75.9	C

4. Calculate the distance between P and points A, B, and C, and then temperatures at P.

$D_{PA} = ((y_P - y_A)^2 + (x_P - x_A)^2)^{½} = 19.5$
$D_{PB} = ((y_P - y_B)^2 + (x_P - x_B)^2)^{½} = 20.2$
$D_{PC} = ((y_P - y_C)^2 + (x_P - x_C)^2)^{½} = 32.9$

so,
$T_d = (T_{dA}D_{PA} + T_{dB}D_{PB} + T_{dC}D_{PC})/(D_{PA} + D_{PB} + D_{PC}) = 99°F$
$T_w = (T_{wA}D_{PA} + T_{wB}D_{PB} + T_{wC}D_{PC})/(D_{PA} + D_{PB} + D_{PC}) = 76°F$

5. The standard barometric pressure for the site is:

$P_{SB} = 29.921 \times (1 - 6.8753 \times 0.000001 \times \text{Elevation})^{5.2559} = 29.12$ inches Hg

SPP Emergency Communication Network
CHANNELING PLAN

Channels	Frequency	Use
1-40		Not used
41-45	500-1600 Khz	AM Broadcast Band--EBS stations
46	20 Mhz	WWV
47	15 Mhz	
48	10 Mhz	
49	5 Mhz	
50	2.5 Mhz	
51-59	20-8 Mhz	Future SPP channels
60-99	8-2 Mhz	Existing SPP channels
100-120		Not used

SPP Emergency Communication Network
CHANNELING INFORMATION GUIDE

Channel Channels	Frequency (kHz) Carrier	Assigned (USB)	Time of day	Geographic Restriction	Class of Station
99	2289.0	2290.4	-	USIA	Fixed, base, or mo
98	2292.0	2293.4	-	"	"
97	2395.0	2396.4	-	"	"
96	2398.0	2399.4	-	"	"
95	3170.0	3171.4	-	"	"
94	4538.6	4540.0	Night only	"	"
93	4548.6	4550.0	"	"	"
92	4575.0	4576.4	-	"	"
91	4610.5	4611.9	-	"	"
90	4613.5	4614.9	-	"	"
89	4634.5	4635.9	-	"	"
88	4637.5	4638.9	-	"	"
87	4647.0	4648.4	-	"	"
86	5046.6	5048.0	-	E of 108 W	Fixed, Itin fixed
85	5052.6	5054.0	-	"	"
84	5055.6	5057.0	-	"	"
83	5061.6	5063.0	-	W of 90 W	"
82	5067.6	5069.0	-	USIA	"
81	5074.6	5076.0	-	E of 108 W	"
80	5099.1	5100.5	-	USIA	"
79	5102.1	5103.5	-	"	"
78	5313.6	5315.0	-	"	"
77	6800.1	6801.5	Night only	"	"
76	6803.1	6804.5	-	"	"
75	6806.1	6807.5	-	W of 90 W	"
74	6855.1	6856.5	Night only	W of Miss River	"
73	6858.1	6859.5	"	USIA	"
72	6861.1	6862.5	-	W of 90 W	"
71	6885.1	6886.5	Night only	USIA	"
70	6888.1	6889.5	"	"	"
69	7480.1	7481.5	-	"	"
68	7483.1	7484.5	-	"	"
67	7486.1	7487.5	-	E of 108 W	"
66	7549.1	7550.5	Day only	USIA	"
65	7552.1	7553.5	-	"	"
64	7555.1	7556.5	-	W of 90 W	"
63	7558.1	7559.5	-	"	"
62	7559.1	7560.5	-	"	"
61	7562.1	7563.5	-	"	"
60	7697.1	7698.5	-	USIA	"

USIA - United States and Insular Areas
Night - 2 hours prior to local sunset till 2 hours after local sunrise
Day - 2 hours after local sunrise till 2 hours before local sunset
" - Ditto

SPP Emergency Communication Network
PROGRAMMING INFORMATION GUIDE

NAME	PROMPT	VALUE	NOTES
Front Panel Channel Programming Enabled	FP Prg	1	*
RX Freq Upper Limit	rF HI	2000000	20 Mhz
RX Freq Lower Limit	rF LO	50000	500 Khz
TX Freq Upper Limit	tF HI	800000	8 Mhz
TX Freq Lower Limit	tF LO	200000	2 Mhz
Operational Level	OPEr L	4	Channelized TX & RX only
ITU Channels Enabled	ItU CH	0	Disabled
Group A Enabled	grOUP A	1	*
Default Sideband Mode for CW, Data, ARQ	dFLt Sb	0	*
Noise Blanker Switch	nb	0	Disabled
Two Tone Alarm	alar	0	*
Data Filter	dt FILt	0	*
CW Filter	C FILt	0	*
Data AGC Speed	d AgC	1	*
CW AGC Speed	C AgC	0	*
ARQ AGC Speed	A AgC	1	*
Low Power/Coupler Sel	LPA CPL	1	RF-3281 Coupler
CW Emissions Mode	C OFFSEt	0	*
Low TX Pwr Below 4 Mhz with 1 KW amplifier	Lo Pr 4	0	*
Data Power Level	dAtA Pr	0	*
CW Power Level	C Pr	0	*
Low Power Selected	Lo Pr	0	*
Channel Scan Time for NON ALE mode	SCAn t	20	*
Channel Dwell Time for NON ALE mode	SCAn dt	20	*
Data,CW, and ARQ Dwell	d-C dt	6000	*
Level 3 Password	PASS 3	XXXXXXX	unique to each radio
Tuning Knob Resolution	tUn rES	4	12 channels per rev
Radio's Self Address	SELF id	XXX	assigned by SPP
Time - Hrs and Mins	Hour	XXXX	Current 24 Hr time (CST)
Sounding Time Interval	Sd intr	0600	
Sounding Start Time	Sd Strt	XXXX	assigned by SPP
LQA Time Interval	bL intr	0000	*
LQA Start Time	bL Strt	0000	*
LQA index	bL ind	---	*
Number of Scan Channels	SCAn CH	8	
Coupler Tuning Time	tUnE ti	2	
Link Timeout	L t OUt	10	automatic return to scan after 10 minutes
All Call Enabled	A CALLS	3	

* These are default values and/or are not used in the SPP Network

SPP Emergency Communication Network
STATION DIRECTORY

INDEX	STATION	SOUND TIME (CST)	CHANNELS AVAILABLE
100	SPP	0706	60 64 72 76 78 84 92 95
101	CAJN	0708	"
102	CESW	0710	"
103	CELE	0712	"
104	CTKS 104 - SPP Net	0714	"
105	CTKS 105	0704	"
106	EMDE 106 - SPP Net	0716	"
107	EMDE 107	0806	"
108	GRRD	0718	"
109	GUSU 109 - SPP Net	0720	"
110	GUSU 110	0702	"
111	GUSU 111	0700	"
112	GUSU 112	0754	"
113	GUSU 113	0756	"
114	GUSU 114	0758	"
115	GUSU 115	0800	"
116	KAMO	0722	"
117	KACP	0724	"
118	KAGE 118 - SPP Net	0726	"
119	KAGE 119	0802	"
120	KAGE 120	0804	"
121	KAPL	0728	"
122	MIPU	0730	"
123	ENTR	0732	"
124	STJO	0734	"
125	ASEC 125 - SPP Net	0736	"
126	ASEC 126	0738	"
127	ASEC 127	0740	"
128	PSOK 128 - SPP Net	0742	"
129	PSOK 129	0752	"
130	SWPS	0744	"
131	SOEP	0746	"
132	WEFA	0808	"
133	KACY	0810	"
134	WEPL	0748	"
135	INDN	0812	"
136	OKGE	0750	"
137	SWPA 137 - SPP Net	0814	"
138	SWPA 138	0658	"
139	SWPA 139	0656	"
140	SWPA 140	0654	"

SPP Emergency Communication Network
NETWORK DIRECTORY

300 - Subregion Coordinators		Channels Available
100	SPP	60 64 72 76 78 84 92 95
121	KAPL	"
123	ENTR	"
125	ASEC	"
128	PSOK	"
108	GRRD	"
301 - Kansas		
104	CTKS	60 64 72 76 78 84 92 95
118	KAGE	"
121	KAPL	"
133	KACP	"
134	WEPL	"
302 - Missouri		
106	EMDE	60 64 72 76 78 84 92 95
117	KACP	"
122	MIPU	"
124	STJO	"
125	ASEC	"
135	INDN	"
303 West Central-1		
102	CESW	60 64 72 76 78 84 92 95
128	PSOK	"
131	SOEP	"
136	OKGE	"
304 - Southeast		
101	CAJN	60 64 72 76 78 84 92 95
103	CELE	"
109	GUSU	"
123	ENTR	"
305 - West Central - 2		
108	GRRD	60 64 72 76 78 84 92 95
116	KAMO	"
130	SWPS	"
132	WEFA	"
137	SWPA	"
306-309 SPP RESERVED		60 64 72 76 78 84 92 95
310-319 Individual Use		60 64 72 76 78 84 92 95

SPP Emergency Communication Network
OPERATING INSTRUCTIONS GUIDE

STATION	INDEX
ASEC	125
KACY	133
CAJN	101
CESW	102
CELE	103
CTKS	104
EMDE	106
ENTR	123
GRRD	108
GUSU	109
INDN	135
KAMO	116
KACP	117
KAGE	118

STATION	INDEX
KAPL	121
MIPU	122
WEPL	134
OKGE	136
PSOK	128
STJO	124
SWPA	137
SWPS	130
SPP	100
SOEP	131
WEFA	132

Networks	
Coordinators	300
Kansas	301
Missouri	302
West Central-1	303
Southeast	304
West Central-2	305

To Place a Call

1. Press 'SCAN' button to remove radio from scan.
2. Select the desired station or network from the above list by rotating the 'TUNING' knob until desired index is displayed.
3. Press and release the microphone button.
   Flashing 'C' is displayed while call is being placed.
   The display changes to a steady 'C' when the link has been established and a ring will sound at both radios.
4. Establish conversation with called party.
5. At end of call, sign off with call sign. Either party can break the link (hang up) by pressing the 'SCAN' button.
   If channel is noisy, perform an LQA as follows:
   a. Open panel door and press 'CLR' button.
      (This returns remote radio to scan)
   b. Press 'LQA' button.
   c. Display shows an 'L' and current channel number while evaluating all available channels.

   After LQA is completed, press and release microphone button to call selected station again.

To Receive a Call

1. Radio will sound call alert signal (ringing tone).
2. When ring stops, press microphone button and identify your station.
3. At end of call, sign off with call sign. Either party can break the link (hang up) by pressing the 'SCAN' button.

CONSIDERATIONS FOR DEVELOPMENT OF BLACK START PLANS

Generation Restoration

Priority should be given to safe shutdown of all power plants.

Priority should be given to preparing units which can be returned to service most rapidly.

Plants with black start capability should have standing orders to begin the process of bringing their units up when the switchyard and all incoming transmission lines are de-energized. The plant should not synchronize or pickup load without communicating with the system operator, unless there are other procedures in effect. Large steam plants will need an outlet for the minimum generation requirement soon after coming on line.

Plants without black start capability should have standing orders to begin preparing the plant for energization from an external line when the switchyard is de-energized. When the bus is energized, it may be necessary to notify the system operator before starting large motors.

Since each plant may be operating independently, plant operators will have to monitor and adjust their unit's voltage and frequency. Frequency should be kept above a predetermined minimum level. Voltage should be kept as close as possible to normal schedules. As more units are brought up and more load is added, the voltage and frequency will tend to stabilize.

Some combustion and steam turbines may have relatively high under-frequency setpoints which could cause unit trips in the initial stages of recovery. Plant operators should be aware of any under-frequency trip setpoints and act accordingly. It is preferable to use the units with lowest under-speed trip setpoints for initial restoration.

Automatic voltage regulators should be placed in service as soon as practical after bringing units on-line and should remain in service to improve machine stability. Automatic governor controls should be immediately placed in service to insure instantaneous governor response to changes in load.

Transmission Restoration

Ties between nearby power plants should be established as soon as possible.

Transmission lines should be energized from the strongest electrical source.

Switching devices on all transmission capacitor banks should be initially open, then closed as needed for voltage control. Energizing transmission autotransformers and shunt reactors at plants will allow plant operators to increase field current on the generators to increase stability. This reactive current will also help keep transmission voltages from becoming excessive.

Caution should be exercised in the use of EHV transmission because of high values of line charging. Energizing one of these circuits with little or no load can produce excessive voltage and can damage substation equipment.

System operators should exercise care when energizing transmission lines, such that they do not close a breaker into a fault. System operators should be aware of any transmission lines that tripped while the system was going down and have field personnel check the relay flags before energizing the line.

Ferroresonance may occur on energizing a line or while picking up a transformer from an unloaded line. System operators should be alert to any unusually high sustained voltages during such switching. EHV lines may be highly susceptible to this phenomenon and their use should be minimized in the early stages of restoration.

Impedance relays that do not have out-of-step blocking may trip lines due to power swings during restoration (a good indication that the line tripped due to excessive power swings rather than a fault is the existence of impedance relay flags and no ground flags).

Load Restoration

In general, 69 kV and 138 kV lines along with radial EHV lines to autotransformers may be used to energize load.

When energizing an EHV circuit and autotransformer combination, both the line and transformer should be energized at the same time to avoid the problem of excessive voltage. The more lightly loaded a generating unit is, the less load increment it can safely pick up.

Cold load pickup can involve inrush currents of 10 or more times the normal load current depending on the nature of the load being picked up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as thirty minutes.

As critical and priority loads are restored, consideration should be given to restoration of loads controlled by under-frequency relays.

When energizing load, system operators must be in close contact with plant operators to avoid excessive load being applied to any unit in a single step. Generally, no more than a predetermined amount of load in an island should be brought back in a single step.

If load is picked up in blocks that are too large, the current inrush may operate over current relays that trip the load off the system again.

There should be sufficient time between switching operations to allow the units to stabilize from the sudden increase in load.

Caution should be exercised when loading a single unit above a predetermined level until additional units have been brought back on-line in that island. Generally, no unit should be loaded to more than a predetermined percentage of its normal rating until network conditions return to normal.

Residential and commercial load will most likely be easier to pick up and maintain than industrial loads. This is due to the large fluctuation possible with industrial loads.

Caution should be exercised when re-energizing capacitor banks after load has been picked up. The change in system voltage that occurs will be much larger than normal because of the reduced system fault duty.

Tie Line Restoration

As system operators pick up load in their areas, a point will be reached at which they will need to energize a line which crosses into another island. At this point, system operators in the affected islands must prepare to synchronize their islands together and close the tie line.

Interconnection should only be attempted at a power plant, or if necessary, at a substation with synchronous indication equipment.

System operators should have field personnel in area islands check breakers at each end of the line to insure they are open regardless of supervisory indication.

The area with the largest amount of generation on line should energize the line first.

Where available, field personnel should synchronize and close the tie breakers at the point of interconnection. If there is a significant frequency difference such that the islands cannot be synchronized, the island with the least generation on line should adjust its frequency to achieve synchronization.

When synchronizing, phase angle across the breaker and the voltage on each side of the breaker should be measured. If possible, the phase rotation should be stopped and the phase angle reduced to a predetermined safe limit before closing the breakers.

Where possible, tie lines should not be loaded to more than a predetermined safe limit until multiple tie paths have been established. Additional ties should be closed as soon as possible to reduce the possibility of re-separation.

MAJOR DISTURBANCE REPORT

SYSTEM _____

REPORTED BY _____

SYSTEM AND/OR AREA AFFECTED _____

_____

CONTROL AREAS AFFECTED _____

_____

DATE AND TIME OF INITIAL DISTURBANCE _____

DATE AND TIME OF INITIAL SERVICE RESTORATION _____

NUMBER OF CUSTOMERS AFFECTED _____

AMOUNT OF LOAD INVOLVED _____

INITIATING CAUSES _____

_____

GENERATORS AND TRANSMISSION LINES WHICH WERE LOST INCLUDING OUTAGE TIMES.

_____

_____

_____

SYSTEM LOAD: PRE-DISTURBANCE ____ MW POST-DISTURBANCE ____ MW

SYSTEM GENERATION: PRE-DISTURBANCE ____ MW POST-DISTURBANCE ____ MW

POWER TRANSFERS: PRE-DISTURBANCE ____ MW (EXPORT OR IMPORT)
POST-DISTURBANCE ____MW (EXPORT OR IMPORT)

CASCADING OUTAGE?	YES ____	NO ____
INSTABILITY?	YES ____	NO ____
UNDERFREQUENCY TRIPPING?	YES ____	NO ____
ISLANDING?	YES ____	NO ____

Appendix A - Ambient Temperature

1.0 Purpose

The purpose of this Appendix is to describe the methodology to be used when determining ambient temperature for circuit rating purposes. This methodology allows for the flexibility of computing ambient temperatures that are location specific and allows for the ease of using default values.

2.0 Types of Ambient Temperature

Maximum ambient temperatures are used when calculating seasonal ratings for overhead conductors, disconnect switches, circuit breakers and wave traps. Average ambient temperatures are used when calculating seasonal ratings for power transformers and current transformers.

2.1 Maximum Ambient Temperature

Circuit rating criteria specify the maximum temperature an overhead conductor, switch, circuit breaker, and wave trap may experience. As the ambient temperature increases, the temperature rise that produces the same maximum equipment temperature is reduced. The reduced temperature rise results in a reduced load carrying capability. Consequently, increases in the maximum ambient temperature does not alter the maximum temperature the equipment was designed to withstand, but it does reduce the current carrying capability for the same maximum equipment temperature.

Selection of the maximum ambient temperature used in rating transmission circuits involves trade-offs. If you select an ambient temperature that is the highest temperature ever recorded for your control area, you may be limiting the use of the transmission system on an ongoing basis for a temperature that has a very small likelihood of occurring. On the other hand, if you select an ambient temperature that is frequently exceeded, you put the transmission system at risk of operating equipment at temperatures in excess of design when it is carrying rated load.

This circuit rating criteria attempts to achieve a balance by specifying a method for determining the maximum ambient temperature that allows for full utilization of the transmission system without experiencing frequent violations of equipment design temperatures. When selecting a maximum ambient temperature for seasonal ratings, a system may choose to either compute a temperature based on local weather station data or may use a default value.

Switches, circuit breakers and wave traps have nameplate ratings based on a 40°C (104°F) maximum ambient temperature (if designed according to ANSI/IEEE standards). The 40°C shall be used as the summer default value for this equipment along with overhead conductors. A system that elects to use the summer default value shall utilize the nameplate rating. Those systems wanting to compute their own maximum ambient temperature shall use the procedure described in section 3.1 and must adjust the nameplate rating using the procedure described in the appropriate appendix for that piece of equipment. The winter default temperature is 10°C (50°F). Whether a system elects to use the winter default value or compute its own, it shall still need to determine winter ratings for overhead conductors, switches, circuit breakers and wave traps using the procedures described in the appropriate appendix (nameplate ratings apply for summer months only).

The maximum ambient temperature, whether based on a default value or a computed value, represents a ceiling or highest number that can be used for rating circuits. A system may rate their equipment at some lower temperature but cannot exceed the default value or the computed value. This allows systems that have historically computed their circuit ratings using an ambient temperature below the default value or the computed value to continue using this value for rating purposes.

However, for a system that has historically utilized an ambient temperature that exceeds both the default value and the computed value, it must lower the maximum ambient temperature it is using for rating purposes such that it equals either the default value or the computed value, whichever of the two the system elects to use.

2.2 Average Ambient Temperature

According to ANSI standards, both power transformers and current transformers are rated using average ambient temperature. The average temperature is calculated by averaging 24 consecutive hourly readings. The maximum daily temperature should not be more than 10°C greater than the average temperature. Power transformers and current transformers both have nameplate ratings based on a 30°C (86°F) average ambient temperature. The 30°C shall be used as the summer default value for this equipment. Using the 30°C average ambient temperature allows for a maximum daily temperature of 40°C that is consistent with the summer default value used for other equipment. The winter default value is 0°C (32°F). It allows a maximum daily temperature of 10°C (50°F) for the winter months and is consistent with the winter default value used for other equipment. A system can elect to compute its own average temperature using the procedure described in Section 3.2. Using a computed average ambient temperature (either summer or winter) for power transformers shall require adjusting its nameplate rating. The default average ambient temperature value of the transformer has been used to determine its emergency rating and an acceptable loss of life. This circuit rating criteria uses the power transformer nameplate rating as a year-round rating (both summer and winter). Consequently, even though an average ambient temperature can be computed, using it to adjust transformer nameplate ratings will affect emergency ratings and is not recommended.

Similar to the maximum ambient temperature the default or computed average ambient temperature represents a ceiling or highest number that can be used for rating power transformers and current transformers. A system can use an average ambient temperature that is less than the default or computed amount but cannot use one that exceeds the default or computed amount.

3.0 Procedure for Computing Ambient Temperature

Systems have the option of either using default values or computing maximum ambient temperature and average ambient temperature. This section describes the procedure for computing ambient temperatures. In general, it is intended that a system would use this procedure a single time and once they have determined their maximum and average ambient temperature, these amounts would remain constant for all future circuit ratings.

When computing ambient temperature, systems shall use temperature readings from nearest weather stations. Some control areas span a large area that may encompass several weather stations. If a large enough geographic area is involved, it is also possible that the computed ambient temperature could be significantly higher at one or more of the weather stations. For these control areas, they may choose to either divide the control area into sections using the highest ambient temperature readings from weather stations within the section or, to maintain consistent ratings throughout the control area, they may choose to use the highest ambient temperature of all weather stations within the control area.

A system is not required to use the same weather station when computing summer and winter ambient temperature. However, the weather station selected must be within the control area or, if there are no weather stations within the control area, it must be the nearest weather station to the control area. Once a weather station is selected for either summer readings or winter readings, all or the readings for each season must come from the same weather station.

3.1 Maximum Ambient Temperature

The summer maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the summer months (June through September). The summer average shall be computed each year for the past five years and the highest average shall be selected as the summer maximum ambient temperature.

The winter maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the winter months (December through February). The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter maximum ambient temperature.

3.2 Average Ambient Temperature

The summer average ambient temperature is determined by averaging the 24 consecutive hourly temperature readings from the nearest weather station for the summer months (June through September). This summer average shall be computed using an average of the five hottest days during the four months. It shall be computed for each year for the past five years and the highest average shall be selected as the summer average ambient temperature.

The winter average ambient temperature shall be computed in a similar manner but shall use the average of the hottest 24 consecutive hourly temperature readings from the nearest weather station for the winter months (December through February). The winter months are defined as the three consecutive months that overlap the end of the year. The winter average shall be computed similar to the summer average using an average of the five hottest days during the three months. The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter average ambient temperature.

Appendix B - Underground Cables

The determination of the ampacity of an underground cable is dependent upon the maximum temperature the conductor can withstand without causing significant thermal deterioration. This temperature can refer to steady-state, emergency or short-circuit conditions. It is the specification of this temperature limit that limits the cable's ampacity. The Neher-McGrath procedure is the basis of steady-state ampacity calculations. This current rating can be calculated by solving the thermal equivalent of Ohm's Law and in its

$$I = \sqrt{\frac{{}_c - T_a - \Delta T_d}{R_{el} \; x \; R_{th}}} \; x \; 10^3 \; A$$

basic form is shown by the equation below:
where

T_c = allowable conductor temperature, °C
T_a = ambient earth temperature, °C
ΔT_d = temperature rise due to dielectric loss, °C
R_{el} = electrical resistance, $\mu\Omega$/ft
R_{th} = thermal resistance, TOF (thermal ohm-feet)

The basic thermal circuit consists of cable heat (in watts) that corresponds to electrical current (in amperes), thermal resistance (in thermal ohm-feet) that corresponds to electrical resistance (in ohms) and temperature drop (in C°) that corresponds to voltage drop (in volts). The electrical analogy and thermal circuit are shown below.

Simply stated, the ampacity calculation consists of the calculation of losses and the temperature rise due to those losses flowing through the various resistances. The procedure can be summarized as follows:

1. Determine the cable construction and conductor size of the existing cable.

2. Refer to AEIC specifications for the maximum allowable conductor temperature for this cable. Determine the temperature rise over ambient earth temperature that will give this value.

3. Calculate dielectric loss.

4. Calculate the electrical resistances of each current-carrying component of the system for the expected operating temperature of that component.

5. Calculate the thermal resistance of each component of the system, including the earth.

6. Calculate the temperature rise due to dielectric loss flowing through the thermal resistances, and subtract that number from the total available temperature rise.

7. Solve the Ohm's law equivalent circuit to determine the ampacity that achieves the allowable temperature rise.

The total thermal circuit for a self-cooled buried transmission cable is shown as an electrical analog in figure below.

The following equations summarize the calculation of the allowable current.

Calculating Allowable Current

$$I = \sqrt{\frac{\Delta T}{\Sigma R_{ac} * \overline{R_{th}}}}, \ (kA)$$

Temperature Rise Due to Dielectric Losses
for pipe-type cables,

$$\Delta T_d = W_d \left(\frac{1}{2} \overline{R_i} + \overline{R_{sd}} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcor}} \right), \ (C^\circ)$$

for single-conductor cables,

$$\Delta T_d = W_d \left(\frac{1}{2} \overline{R_i} + \overline{R_j} + \overline{R_{sd}} + \overline{R_d} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcor}} \right), \ (C^\circ)$$

where

R_i	=	insulation thermal resistance (TOF)
R_j	=	jacket thermal resistance (TOF)
R_{sd}	=	thermal resistance between cable surface and surrounding enclosure (TOF)
R_d	=	duct thermal resistance (TOF)
R_{pc}	=	pipe-covering thermal resistance (TOF)
$R_{de'}$	=	earth thermal resistance for dielectric losses (TOF)
R_{dcorr}	=	correction factor for controlled backfill or concrete-encased duct (TOF)

Available Temperature Rise for Current-Dependent Losses

$$\Delta T_c = T_c - T_a - \Delta T_d - \Delta T_{int}, \ (C^\circ)$$

where

T_c	=	allowable conductor temperature (C°)
T_a	=	ambient earth temperature (C°)
ΔT_d	=	conductor temperature rise due to dielectric and charging-current losses (C°)
ΔT_{int}	=	temperature rise due to extraneous heat source (C°)

Summation of Electrical and Thermal Resistances
for pipe-type cables:

$$\sum R_{ac}\overline{R_{th}}°C/kA^2 = R_{acc}\overline{R_i} + R_{acs}\overline{R_{sd}} + R_{acp}\overline{R_{pc}} + R_{acp}\overline{R_{dx}} + R_{acp}\overline{R_{earth}} + R_{acp}\overline{R_{mut}} + R_{acp}\overline{R_{ccorr}}$$

for single-conductor cables:

$$\sum R_{ac}\overline{R_{th}}°C/kA^2 = R_{acc}\overline{R_i} + R_{acs}\overline{R_j} + R_{acs}\overline{R_{sd}} + R_{acs}\overline{R_d} + R_{acs}\overline{R_{dx}} + R_{acs}\overline{R_{earth}} + R_{acs}\overline{R_{mut}} + R_{acs}\overline{R_{ccorr}}$$

where

D_e	=	diameter at start of the earth or external portion of the thermal circuit (in.)
D_x	=	fictitious diameter at which the effect of loss factor begins (in.)
R_{acc}	=	conductor ac resistance ($\mu\Omega$/ft)
R_{acp}	=	ac resistance at pipe ($\mu\Omega$/ft)
R_{acs}	=	ac resistance at shield ($\mu\Omega$/ft)
R_{ccorr}	=	correction factor, current-dependent losses (TOF)
R_{dx}	=	thermal resistance from D_e to diameter D_x (TOF)
R_{earth}	=	thermal resistance from D_x to ambient earth (TOF)
R_{mut}	=	mutual-heating earth thermal resistance term (TOF)

For further and more detailed information see the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity. The above equations apply to buried cable installations. For above ground installation (e.g. bridge crossings, tunnel installations or riser sections), there are three main differences. First, solar radiation provides heat input. The Neher-McGrath method does not consider this factor. Second, heat transfer by conduction is negligible. And third, heat transfer for cables in air is by free or forced convection and by radiation. Generally, the ampacity of an identical cable circuit installed in the air will be greater than that for a buried cable circuit. The equations will not be presented here and may be found in the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity.

Under emergency conditions it may become necessary to exceed the normal temperature limit of the cable. A new cable rating may be calculated by substituting the new temperature limit into the equations seen above. The key to calculating the emergency rating will be establishing the allowable temperature increase. One must be careful not to overestimate the ability of the cable to withstand higher temperatures as well as not to underestimate the loss of life that will occur with operation above normal temperatures.

APPENDIX C - Switches

Switch ratings are discussed in ANSI/IEEE C37.37-1979, **Loading Guide for AC High-Voltage Air Switches (in excess of 1000 volts)** and in ANSI/IEEE C37.37a-1992, **IEEE Loading Guide for AC High-Voltage Air Switches Under Emergency Conditions**. In general, the allowable continuous current of a switch is based on the allowable maximum temperature of the switch parts and is affected by the ambient temperature. Provisions are made for loading the switches under emergency conditions in the above referenced ANSI/IEEE Standard C37.37a-1992. Therefore, both Normal and Four-Hour Emergency circuit ratings will be developed based upon the allowable continuous current capability rating of the switch. These ratings will be treated as the loading limits for normal and emergency conditions.

A switch is made up of a number of different switch parts, which are classified and grouped in accordance with their material and function into switch part classes, each of which is given a switch part class designation of the form xO#. Examples of the switch part class designations are AO1, DO6, JO10, NO1, and WO9. The loadability factors of each switch part class, as a function of ambient temperature, are represented by a curve. Tabular representations of these curves for normal, continuous load conditions are contained in Table C - 3 for non-enclosed indoor and outdoor switches and in Table C - 4 for enclosed indoor and outdoor switches. Tabular representations of these curves for emergency load conditions with a maximum emergency loading duration of four hours are contained in Table C - 5 for non-enclosed indoor and outdoor switches and in Table C - 6 for enclosed indoor and outdoor switches.

The Allowable Continuous Current Class (ACCC) designation of a switch is a code which identifies a composite loadability curve made up from the limiting switch part classes. In most instances, the ACCC designation will be contained on the switch's nameplate. However, air switches designed in accordance with ANSI C37.30-1962 and earlier may not have an ACCC designation on the nameplate. Such non-enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 40°C, indicative of an allowable maximum temperature of 70°C, are assigned an ACCC designation of AO1. In like manner, such enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 55°C, indicative of an allowable maximum temperature of 85°C, are assigned an ACCC designation of NO1.

ACCC designations were developed such that the first character, x, designates that the specific normal loadability factors for that class are represented by Curve x when the ambient is between 60°C and 25°C.; the second character in the ACCC designation, O, represents the specific normal loadability factor for that class at 25°C. (All curves intersect at O and have a loadability factor of 1.22 at 25°C ambient); and the third character, #, designates that the specific normal loadability factors for that class are represented by Curve # when the ambient is between 25°C and -30°C.

In some instances, a composite curve must be developed due to the fact that the switch is constructed such that some parts of the switch have different switch part class designations than other parts of the switch. In this situation, the switch's ACCC designation will differ from the standard ACCC designations listed in the tables and instead will be a composite of two of the standard ACCC designations. An example of this would be a switch having a designation of DO6, signifying that the switch is constructed using some parts having the switch part class designations of DO4 and some parts having the switch part class designations of FO6.

Based upon the ACCC designation of a switch, a normal loadability factor curve can be developed for the switch in the following manner.

1. Using Table C - 2 for non-enclosed indoor and outdoor switches or Table C - 3 for enclosed indoor and outdoor switches, the appropriate values for Curve x, Curve O, and Curve # are determined based upon the switch's ACCC designation. These curves will be joined together to form a composite normal loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2. The normal loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the normal loadability factor for a specific temperature, which is not represented in the composite table, is desired, the normal loadability factor may be calculated by interpolating between the nearest known values. In no case shall the normal loadability factor exceed 2.00.

3. The Allowable Continuous Current Capability of a switch at a given ambient temperature is equal to the normal loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Allowable Continuous Current Capability of a switch at a given ambient temperature will be treated as the normal ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

(a) Develop a loadability factor table for a 1200-amp non-enclosed switch with ACCC designation DO6.

(b) Using this table, determine the Allowable Continuous Current Capability of this switch at an ambient temperature of 0°C.

Solution:

(a) The normal loadability factor table, Table C - 1, was created using Table C - 3 for a non-enclosed switch with ACCC designation DO6. For the temperatures from 25°C to 60°C, the loadability factors from Curve D were used. The standard loadability factor of 1.22 was used for an ambient of 25°C. The loadability factors from Curve 6 were used for the temperatures from 20°C to -30°C.

(b) Based upon Table C - 1, the Allowable Continuous Current Capability of a 1200-A non-enclosed switch designated DO6 at 0°C would be:

Loadability Factor @ 0°C * Rated Current

or

1.41 * 1200 amps = 1692 amps

For operation at 0°C, the Normal rating of switch would be 1692 amps.

Maximum Ambient Temperature	Loadability Factor	Curve Used
60°C	0.84	Curve D
50°C	0.96	
40°C	1.07	
30°C	1.18	
25°C	1.22	Standard
20°C	1.27	Curve 6
10°C	1.34	
0°C	1.41	
-10°C	1.47	
-20°C	1.54	
-30°C	1.60	

Table C - 1: Normal Loadability Factors for a Type DO6 Switch

The Four-Hour Emergency Load Current carrying capability of a switch can be determined based upon the switch's ACCC designation. A four-hour emergency loadability factor curve can be developed for the switch in the following manner.

1. Using Table C - 5 for non-enclosed indoor and outdoor switches or Table C - 6 for enclosed indoor and outdoor switches, the appropriate emergency loadability factors are determined based upon the switch's ACCC designation. In developing the composite curve, the emergency loadability factor curves of the two standard ACCC designations must be examined and the most limiting loadability factor at each ambient temperature will be used to form a composite emergency loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2. The emergency loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the emergency loadability factor for a specific temperature, which is not represented in the composite table, is desired, the emergency loadability factor may be calculated by interpolating between the nearest known values. In no case shall the emergency loadability factor exceed 2.00.

3. The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature is equal to the emergency loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature will be treated as the Emergency ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

(a) Develop an emergency loadability factor table for a 1200-amp non-enclosed switch with ACCC designation DO6.

(b) Using this table, determine the Four-Hour Emergency Load Current Capability of this switch at an ambient temperature of 0°C.

Solution:

(a) The emergency loadability factor table, Table C - 2, was created using Table C - 5 for a non-enclosed switch with ACCC designation DO6. The composite curve was developed by examining the emergency loadability curves for switches having ACCC designations of DO4 and FO6. At each of the ambient temperatures, the most limiting loadability factor was chosen from the DO4 and FO6 curves to form the composite curve.

(b) Based upon Table C - 3, the Four-Hour Emergency Load Current Capability of a 1200-A non-enclosed switch designated DO6 at 0°C would be:

Emergency Loadability Factor @ 0°C * Rated Current

or

1.54 * 1200 amps = 1848 amps

For operation at 0°C, the Four-Hour Emergency ratings of the switch would be 1848 amps.

Maximum Ambient Temperature	Loadability Factor Curve DO4	Loadability Factor Curve FO6	Composite Curve for a DO6 Switch
60°C	**1.08**	1.11	**1.08**
50°C	**1.18**	1.19	**1.18**
40°C	1.28	**1.27**	**1.27**
35°C	1.32	**1.30**	**1.30**
30°C	1.36	**1.34**	**1.34**
25°C	1.41	**1.37**	**1.37**
20°C	1.45	**1.41**	**1.41**
10°C	1.53	**1.47**	**1.47**
0°C	1.60	**1.54**	**1.54**
-10°C	1.67	**1.60**	**1.60**
-20°C	1.74	**1.65**	**1.65**
-30°C	1.81	**1.71**	**1.71**

Table C - 2: Four-Hour Emergency Loadability Factors for a Type DO6 Switch

Maximum Ambient Temperature		ACCC Designation																					
		AO1		BO2		CO3		DO4		EO5		FO6		GO7		HO8		IO9		JO10		KO11	
°C	°F																						
60	140	0.58	Curve A	0.67	Curve B	0.74	Curve C	0.84	Curve D	0.86	Curve E	0.92	Curve F	0.94	Curve G	0.98	Curve H	1.03	Curve I	1.06	Curve J	1.10	Curve K
50	122	0.82		0.87		0.90		0.96		0.98		1.02		1.03		1.05		1.09		1.12		1.14	
40	104	1.00		1.03		1.04		1.07		1.08		1.11		1.11		1.13		1.15		1.16		1.18	
30	86	1.15		1.17		1.17		1.18		1.18		1.19		1.19		1.20		1.20		1.20		1.21	
25	77	1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	68	1.29	Curve 1	1.29	Curve 2	1.28	Curve 3	1.28	Curve 4	1.27	Curve 5	1.27	Curve 6	1.27	Curve 7	1.26	Curve 8	1.25	Curve 9	1.24	Curve 10	1.24	Curve 11
10	50	1.41		1.40		1.38		1.36		1.34		1.34		1.32		1.32		1.30		1.28		1.28	
0	32	1.53		1.51		1.47		1.45		1.42		1.41		1.39		1.38		1.34		1.32		1.31	
-10	14	1.63		1.60		1.56		1.52		1.49		1.47		1.45		1.44		1.39		1.36		1.34	
-20	-4	1.73		1.70		1.64		1.60		1.56		1.54		1.51		1.49		1.44		1.40		1.37	
-30	-22	1.83		1.78		1.72		1.67		1.63		1.60		1.57		1.54		1.48		1.44		1.40	

Table C - 3: Non-enclosed Indoor and Outdoor Switches
Switch Part Normal Loadability Factors (LF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation																					
		$QO_3$3		$PO_2$2		NO1		RO4		SO5		TO6		UO7		VO8		WO9		XO10		YO11	
°C	°F																						
60	140	0.00	Curve Q	0.45	Curve P	0.58	Curve N	0.67	Curve R	0.74	Curve S	0.84	Curve T	0.86	Curve U	0.92	Curve V	1.00	Curve W	1.05	Curve X	1.09	Curve Y
50	122	0.71		0.77		0.82		0.87		0.90		0.96		0.98		1.02		1.07		1.10		1.13	
40	104	1.00		1.00		1.00		1.03		1.04		1.08		1.08		1.11		1.13		1.15		1.17	
30	86	1.22	Curve 3	1.18	Curve 2	1.15		1.16		1.16		1.18		1.18		1.19		1.20		1.20		1.20	
25	77	1.32		1.26		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	68	1.41		1.34		1.29	Curve 1	1.29	Curve 4	1.28	Curve 5	1.28	Curve 6	1.26	Curve 7	1.26	Curve 8	1.25	Curve 9	1.25	Curve 10	1.24	Curve 11
10	50	1.58		1.48		1.41		1.40		1.38		1.36		1.35		1.34		1.31		1.29		1.28	
0	32	1.73		1.61		1.53		1.51		1.47		1.45		1.42		1.41		1.36		1.34		1.31	
-10	14	1.87		1.73		1.63		1.61		1.56		1.53		1.50		1.47		1.41		1.40		1.35	
-20	-4	2.00		1.84		1.73		1.70		1.64		1.60		1.56		1.54		1.46		1.42		1.38	
-30	-22	2.00		1.95		1.83		1.78		1.72		1.67		1.63		1.60		1.51		1.46		1.41	

Table C - 4: Enclosed Indoor and Outdoor Switches
Switch Part Normal Loadability Factors (LF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		AO1	BO2	CO3	DO4	EO5	FO6	GO7	HO8	IO9	JO10	KO11
°C	°F											
60	140	1.00	1.03	1.04	1.08	1.08	1.11	1.11	1.13	1.15	1.16	1.18
50	122	1.15	1.17	1.16	1.18	1.18	1.19	1.18	1.20	1.20	1.20	1.21
40	104	1.29	1.29	1.27	1.28	1.26	1.27	1.26	1.26	1.25	1.24	1.24
35	95	1.35	1.35	1.33	1.32	1.30	1.30	1.29	1.29	1.27	1.26	1.26
30	86	1.41	1.40	1.38	1.36	1.34	1.34	1.32	1.32	1.30	1.28	1.28
25	77	1.47	1.46	1.42	1.41	1.38	1.37	1.36	1.35	1.32	1.30	1.29
20	68	1.53	1.51	1.47	1.45	1.42	1.41	1.39	1.38	1.35	1.32	1.31
10	50	1.63	1.61	1.56	1.53	1.49	1.47	1.45	1.44	1.39	1.36	1.34
0	32	1.73	1.70	1.64	1.60	1.56	1.54	1.51	1.49	1.44	1.40	1.37
-10	14	1.83	1.78	1.72	1.67	1.63	1.60	1.57	1.54	1.48	1.44	1.40
-20	-4	1.92	1.87	1.80	1.74	1.69	1.65	1.62	1.59	1.52	1.47	1.43
-30	-22	2.00	1.95	1.87	1.80	1.76	1.71	1.68	1.64	1.56	1.51	1.45

Table C - 5: Non-enclosed Indoor and Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		$QO_3$3	$PO_2$2	NO1	RO4	SO5	TO6	UO7	VO8	WO9	XO10	YO11
°C	°F											
60	140	1.00	1.00	1.00	1.03	1.04	1.08	1.08	1.11	1.13	1.15	1.17
50	122	1.22	1.18	1.15	1.17	1.16	1.18	1.18	1.19	1.20	1.20	1.21
40	104	1.41	1.34	1.29	1.29	1.27	1.28	1.26	1.27	1.25	1.25	1.24
35	95	1.50	1.41	1.35	1.35	1.33	1.32	1.30	1.30	1.28	1.27	1.26
30	86	1.58	1.48	1.41	1.40	1.38	1.36	1.34	1.34	1.31	1.29	1.28
25	77	1.66	1.55	1.47	1.46	1.42	1.41	1.38	1.37	1.34	1.31	1.30
20	68	1.73	1.61	1.53	1.51	1.47	1.45	1.42	1.41	1.36	1.33	1.31
10	50	1.87	1.73	1.63	1.61	1.56	1.53	1.49	1.47	1.41	1.38	1.35
0	32	2.00	1.84	1.73	1.70	1.64	1.60	1.56	1.54	1.46	1.42	1.38
-10	14	2.00	1.95	1.83	1.78	1.72	1.67	1.63	1.60	1.51	1.46	1.41
-20	-4	2.00	2.00	1.92	1.87	1.80	1.74	1.69	1.65	1.56	1.50	1.44
-30	-22	2.00	2.00	2.00	1.95	1.87	1.80	1.76	1.71	1.60	1.54	1.47

Table C - 6: Enclosed Indoor and Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

APPENDIX D - Wave Traps

Wave trap ratings are discussed in several sources. The ratings for the older wave traps in which the main coil is designed as a single-phase, air-cored inductor of the dry type are discussed in ANSI C93.3-1981, **Requirements for Power-Line Carrier Line Traps** and in Westinghouse Electric's Curve No. 511545 (Copy included in this Appendix). The ratings of the newer type of wave traps consisting of a coil of wire encapsulated in an epoxy resin are not covered in an ANSI/IEEE standard. The ratings for this type of wave trap were developed based upon guidelines supplied by the manufacturer, Trench Electric, (Copy included in this Appendix). In general, the rated continuous current for wave traps is based on the maximum permissible temperature rise limitations of the wave trap when it is carrying rated current at an ambient temperature of 40°C. The total temperature of the wave trap under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature rise limitation is not exceeded.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of both types of wave traps. These seasonal ratings will be based on the nameplate rating of the wave trap with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The ambient-compensated normal loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D - 1 and were obtained from Westinghouse Electric's Curve No. 511545. The ambient-compensated loadability factors for Epoxy-Encapsulated Inductor wave traps were developed from Trench Electric's loadability curves and are given in Table D - 2. To determine the normal seasonal circuit rating, simply multiply the wave trap's nameplate rating by the appropriate normal loadability factor. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Normal life expectancy will occur with a wave trap operated at or below its ambient-compensated normal current rating. Any value of currents in excess of the ambient-compensated normal current ratings may cause the designed temperature rise to be exceeded and may shorten the life expectancy of the wave trap. For wave traps utilizing an air-cored inductor, an acceptable level of emergency overload current has been determined and is specified in ANSI Standard C93.3-1981, **Requirements for Power-Line Carrier Line Traps**. Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of wave traps utilizing an air-cored inductor. These seasonal ratings will be based on the Four-Hour Emergency Overload Current-Carrying capability of the wave trap with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The wave traps may be loaded to this emergency level for a maximum of four hours per cycle. Before an emergency load cycle, the wave trap loading must be at or below the normal seasonal loading level for at least two hours.

The emergency seasonal circuit rating can be developed by simply multiplying the wave trap's nameplate rating by the appropriate emergency loadability factor. The ambient-compensated emergency loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D - 1 and were obtained from ANSI Standard C93.3-1981, **Requirements for Power-Line Carrier Line Traps**. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Average Ambient Air Temperature	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	1.10
20°C	1.05	1.15
0°C	1.10	1.20
-20°C	1.10	1.25

Table D - 1: Loadability Factors for Dry-Type Air-Cored Inductor Wave Traps

Average Ambient Air Tempera0ure	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	N/A
20°C	1.13	N/A
0°C	1.25	N/A
-20°C	1.36	N/A

Table D - 2: Loadability Factors for Epoxy-Encapsulated Inductor Wave Traps

Trench Electric, the manufacturer of the newer type of wave traps which consist of a coil of wire encapsulated in an epoxy resin, has stated that no overload capability is available on this type of wave trap. For this reason, no separate emergency rating will be assigned to this type of wave trap and the ambient-compensated current rating will be used for both the circuit's normal and emergency ratings.

July 16, 1985

Westinghouse Electric Corporation

Subject: Line Trap Loadings

Attached is one copy of the Appendix to ANSI Standard C93.3-1981 titled "Guide for Emergency Overload Current Capability of Line Traps".

This guide is current and, all Westinghouse traps built since 1970 conforms to the overload capability designated therein.

The Curve No. 511545 supplied applies to Westinghouse Line Traps built prior to 1970. Note that the overload capability of traps 2000 amperes and below on this curve are the same as that specified in the Standard. The larger traps were modified in design in order to conform to the Standard requirement.

July 25, 1985

Trench Electric

Attached are three copies of the overload current U.S. temperature curves. General Electric did not send any such information when we purchased their Line Trap division but the curves should be approximately the same.

APPENDIX E - Current Transformers

Current transformer ratings are discussed in ANSI/IEEE C57.13-1978, **IEEE Standard Requirements for Instrument Transformers** and in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers"** (Copy included in this Appendix). In general, the rated continuous current for current transformers is based on the maximum permissible temperature limitations of the various parts of the current transformer when it is carrying rated current at a 24-hour average ambient temperature of 30°C (with a maximum hourly temperature of 40°C). The total temperature of these parts under service conditions depends both on the actual load current, the actual average ambient temperature, and the service environment of the current transformer. Depending on the environment, it is, therefore, possible to operate at a current higher than rated continuous current when the average ambient temperature is less than 30°C, provided that the allowable total temperature limit is not exceeded. Similarly, when the average ambient temperature is greater than 30°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

The environment in which a current transformer operates has a large effect on the current-carrying capability of the current transformer. Separately mounted current transformers have been assigned rated primary and secondary currents and continuous-thermal-current rating factors by the manufacturer. Separately mounted current transformers are designed to meet these characteristics by the independent control of such parameters as: current density in the primary and secondary windings, geometry, area of radiating surfaces, and heat transfer characteristics. Permissible loading as a function of ambient temperatures and continuous-thermal-current rating factors, and permissible overloading under emergency conditions, is covered in ANSI/IEEE C57.13-1978, **IEEE Standard Requirements for Instrument Transformers**.

Bushing current transformers mounted in power circuit breakers and power transformers differ from separately mounted current transformers in that the design parameters cannot be independently controlled since they are restricted by the characteristics of the power apparatus in which they are mounted. Bushing current transformers, when attached to various power apparatus, are subjected to wide variations in their environmental ambient temperature. This variation is dependant upon the thermal characteristics of the power apparatus and the relative current loading with respect to the rated current of the power apparatus and its bushing current transformer. For this reason, continuous-thermal-current rating factors are not typically calculated by the manufacturer for bushing current transformers. Instead, the continuous-thermal-current rating factors must be determined for each application. Permissible loading and permissible overloading of bushing current transformers is covered in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers"**.

Rating Separately Mounted Current Transformers: The maximum continuous-thermal-current ratings for separately-mounted current transformers designed for 55°C temperature rise above 30°C average ambient air temperature will vary according to actual ambient cooling air temperature. The adjusted continuous current ratings will be based on three items:

1. The nameplate primary and secondary current ratings at the ratio setting being used.

2. The average cooling air temperature at which the rating is being calculated. **Note:** The maximum cooling air temperature must not exceed the average cooling air temperature by more than 10°C.

3. The ambient-adjusted Continuous-Thermal-Current rating factor from Table E - 1. The value used from this table is based upon the nameplate Continuous-Thermal-Current rating factor of the current transformer and the average ambient air temperature.

Average Cooling Temperature (°C)	Nameplate Continuous-Thermal-Current Rating Factor					
	1.00	**1.33**	**1.50**	**2.00**	**3.00**	**4.00**
60°C	0.65	0.85	1.00	1.35	2.00	2.70
50°C	0.80	1.05	1.20	1.60	2.40	3.20
40°C	0.90	1.20	1.35	1.80	2.70	3.65
30°C	1.00	1.33	1.50	2.00	3.00	4.00
20°C	1.05	1.45	1.65	2.20	3.30	4.35
10°C	1.20	1.55	1.75	2.35	3.50	4.70
0°C	1.30	1.65	1.85	2.45	3.70	5.00

Table E - 1: Ambient-Adjusted Continuous-Thermal-Current Rating Factors

The ambient-adjusted continuous-thermal-current rating of a separately-mounted current transformer is equal to the ambient adjusted continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified. According to ANSI/IEEE C57.13-1978, **IEEE Standard Requirements for Instrument Transformers**, no overload capability is available on separately-mounted current transformers. For this reason, normal rating of the separately-mounted current transformer will be used for both the normal seasonal circuit rating and the emergency seasonal circuit rating.

Example: The following example should serve to clarify this process:

Problem:

(a) Determine the summer seasonal normal and emergency ratings for a separately-mounted current transformer operating on a 2000:5 amp ratio with a nameplate Continuous-Thermal-Current rating of 1.50. Assume the average ambient air temperature is 30°C with a maximum temperature of 40°C for the summer period.

(b) Determine the winter seasonal normal and emergency ratings for this same separately-mounted current transformer assuming an average ambient air temperature of 0°C with a maximum temperature of 10°C for the winter period.

Solution:

(a) From Table E - 1, the 30°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.50 (They are the same due to the fact that the nameplate C-T-C rating factor is developed at an average ambient of 30°C). The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 30°C * Rated Primary Current of CT Ratio

or

1.50 * 2000 amps = 3000 amps

For operation at 30°C, both the Summer Normal and Emergency ratings of current transformer would be 3000 amps. **Note:** When the primary current is 3000 amps, the secondary current would be 7.5 amps due to the 2000:5 ratio used in the current transformer.

(b) From Table E - 1, the 0°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.85. The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 0°C * Rated Primary Current of CT Ratio

or

1.85 * 2000 amps = 3700 amps

For operation at 0°C, both the Winter Normal and Emergency ratings of current transformer would be 3700 amps. **Note:** When the primary current is 3700 amps, the secondary current would be 9.25 amps due to the 2000:5 ratio used in the current transformer.

Rating Bushing Current Transformers Mounted in Power Apparatus: The continuous current rating of current transformers mounted in power circuit breakers or power transformers is determined as follows:

1. When the bushing current transformer ratio being used has the same primary current rating as the breaker continuous current rating or the power transformer rated current, the continuous current rating factor of the current transformer is 1.0 (unity).

2. When the primary current rating of the ratio being used on the current transformer is greater than the continuous current rating of the breaker or greater than the power transformer rated current, then the maximum load current is limited by the breaker or power transformer rating, which ever is applicable.

3. When the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, then the maximum load current is limited by the continuous thermal current rating of the current transformer when operating on that ratio. Under these conditions, the temperature rises of the current transformer and the power apparatus would be lower, and therefore, the current transformer can be operated at a continuous thermal rating factor greater than 1.0. In this situation, the permissible continuous-thermal-current rating factor is calculated based upon a constant maximum power dissipation, using the following equation:

$$R.F. = \left[\frac{I_{pa}}{I_{ct}} \right]^{1/2}$$

where

R.F. = Continuous-thermal-current rating factor

I_{pa} = Power apparatus continuous current rating (amps)

I_{ct} = Primary current rating of bushing current transformer ratio used (amps)

The results calculated from this equation should be so limited that the maximum rating factor does not exceed 2.0 and that the continuous current rating of the breaker or the rated current of the power transformer is not exceeded.

Note: The situation in which the primary current rating of the current transformer ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, is an unusual case and should be viewed as the exception rather than the rule.

The normal rating of a bushing current transformer is equal to the continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified.

Some short-term emergency overload capability is typically available on bushing current transformers mounted on power circuit breakers and power transformers. However, when utilizing this emergency overload capability, care must be taken to coordinate the loading limit of the current transformer with the overall application limitations of the other equipment affected by the current transformer loading. Particular care should be taken to avoid exceeding the maximum metering capability of metering equipment attached to the current transformer secondary.

APPENDIX F - Circuit Breakers

Circuit breaker ratings are discussed in ANSI/IEEE C37.010-1979, **IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis** and in ANSI/IEEE C37.010b-1985, **IEEE Standard for Emergency Load Current-Carrying Capability**. These standards discuss the development of ratings for circuit breakers from the standpoint of the manufacturers. From a practical standpoint, the application of the methods discussed in these standards to circuit breakers in operation will be very difficult, due to the fact that this application would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Therefore, it is recommended that for any circuit breakers which do not limit flows on the transmission system, the nameplate rated continuous current be used as the circuit breaker's normal and emergency circuit ratings. For circuit breakers which limit flows on the transmission system, the manufacturer could be consulted and ambient-compensated normal and emergency ratings could be developed for the circuit breaker using the methods described in the ANSI/IEEE Standards. These methods are described in the remainder of this Appendix.

In general, the rated continuous current for circuit breakers is based on the maximum permissible temperature limitations of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The total temperature of these parts under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature limit is not exceeded. Similarly, when the ambient temperature is greater than 40°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the nameplate rating of the circuit breaker with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The seasonal loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers. (See other appropriate appendices to determine limitations on the other equipment.) For circuit breakers used in metal-clad switchgear, no seasonal ratings will be calculated. Instead, the loading limit shall be coordinated with the overall application limitations of the switchgear.

The seasonal normal circuit breaker ratings can be determined in the following manner:

1. A circuit breaker's rated continuous current is based on the maximum permissible total temperature limitations, $Ø_{max}$ and $Ø_r$, of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The constructional features of a circuit breaker dictate the appropriate values of $Ø_{max}$ and $Ø_r$ to be used in the calculation of ambient-compensated ratings. The major components of a circuit breaker have several different temperature limitations which are shown in Table F - 1.
   In order that none of these temperature limitations be exceeded when the load current is adjusted to the value permitted by the actual ambient temperature, the values of $Ø_{max}$ and $Ø_r$ should be determined as follows:

   (a) If the actual temperature is less than 40°C, the applicable component with the highest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and $Ø_r$.

   (b) If the actual temperature is greater than 40°C, the applicable component with the lowest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and $Ø_r$.

Component Description	Limit of Temperature Rise, °C $Ø_r$	Limit of Total Temperature, °C $Ø_{max}$
Circuit breaker parts handled by the operator in the normal course of his duties.	10	50
Copper contacts, copper-to-copper conducting joints, external surfaces accessible to the operator in the normal course of his duties, external terminal connected to bushing	30	70
Top oil	40	80
Breaker terminals to be connected to 85°C insulated cable	45	85
Hottest spot temperature of parts where they contact oil; silver (or equal) contacts in oil; Silver (or equal) conducting joints in oil	50	90
Silver (or equal) contacts in air; silver (or equal) conducting joints in air; hottest spot of bushing conductor or of bushing metal parts in contact with Class A insulation or with oil; hottest spot winding temperature 55°C rise of current transformers	65	105
External surfaces not accessible to an operator in the normal course of his duties	70	110
Hottest spot winding temperature of 80°C dry-type current transformers	110	150

Table F - 1: Summary of Temperature Limitations for Circuit Breaker Components

2. The continuous current which a circuit breaker can carry at a given ambient temperature without exceeding its total temperature limitations is given by the formula:

$$I_a = I_r \left[\frac{Ø_{max} - Ø_a}{Ø_r} \right]^{1/1.8}$$

where

I_a = allowable continuous load current, in amperes, at the actual ambient temperature $Ø_a$ (I_a is not to exceed two times I_r

I_r = rated continuous current, in amperes

$Ø_{max}$ = allowable hottest spot total temperature ($Ø_{max} = Ø_r + 40°C$), in degrees Celsius

$Ø_a$ = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius

$Ø_r$ = allowable hottest spot temperature rise at rated current, in degrees Celsius

3. The ambient-compensated allowable continuous load current, I_a, calculated in Step 2 will be treated as the seasonal normal rating of the circuit breaker.

Normal life expectancy will occur with a circuit breaker operated at continuous nameplate rating. When operated for one or more load cycles above nameplate rating, the material used in manufacturing the circuit breaker deteriorates at a faster rate than normal. The rate of deterioration is commonly expressed as a percentage loss of life. According to ANSI/IEEE C37.010b-1985, **IEEE Standard for Emergency Load Current-Carrying Capability**, a circuit breaker can experience operation at 10°C above the limits of total temperature for which the circuit breaker was designed for up to two periods of an emergency cycle of eight hours before an unreasonable loss of life occurs and maintenance is required. Inspection and maintenance must be performed in accordance with manufacturer's recommendations before the circuit breaker can be subjected to additional emergency cycles. In addition, following each emergency cycle, the load current shall be limited to 95% of the rated continuous current as modified by ambient compensation for a minimum of two hours.

Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the Eight-Hour Emergency Load Current-Carrying capability of the circuit breaker with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The seasonal emergency loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers.

The seasonal emergency circuit breaker ratings can be determined in the following manner:

1. Emergency load current-carrying capability factors with ambient temperatures at 40°C are listed in Table F - 2 for each limiting temperature of various circuit breaker components. The factors have been selected to allow operation at 10°C above the limits of total temperature for an emergency period of eight hours. The factors are expressed as the ratio of emergency load current allowed at an ambient temperature of 40°C, I_e, to the rated continuous current, I_r, and can be applied with the following restrictions:

   (a) The circuit breaker component with the highest values of limiting temperature, $Ø_{max}$ and $Ø_r$, shall be used to select the proper emergency load current-carrying capability factor from Table F - 2.

   (b) The Eight-Hour factor shall be used for a cycle of operation consisting of separate periods of not longer than eight hours each, with not more than two such occurrences before maintenance.

   (c) Each cycle of operation is separate, and no time-current integration is permissible to increase the number of periods within a given maintenance cycle.

	Limiting Temperatures (°C) of Different Breaker Components						
$Ø_{max}$	70	80	85	90	105	110	150
$Ø_r$	30	40	45	50	65	70	110
	1.17	1.13	1.11	1.10	1.08	1.07	1.05

Table F - 2: Emergency Load Current-Carrying Capability Factor (I_e/I_r)

2. The emergency load current, I_{ea}, of a circuit breaker operating at an ambient temperature other than 40°C can be calculated by the equation:

$$I_{ea} = I_r \left[\frac{\emptyset_{max} - \emptyset_a}{\emptyset_r} + \frac{I_e^{1.8}}{I_r^{1.8}} - 1 \right]^{1/1.8}$$

where

I_{ea} = emergency load current, in amperes, at the actual ambient temperature $\emptyset_a$ (I_{ea} is not to exceed two times I_r)

I_r = rated continuous current, in amperes

I_e = emergency load current, in amperes, at 40°C ambient temperature

$\emptyset_{max}$ = allowable hottest spot total temperature ($\emptyset_{max} = \emptyset_r + 40°C$), in degrees Celsius

$\emptyset_a$ = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius

$\emptyset_r$ = allowable hottest spot temperature rise at rated current, in degrees Celsius

$\frac{I_e}{I_r}$ = emergency load current-carrying capability factor from Table F - 2

3. The ambient-compensated emergency load current, I_{ea}, calculated in Step 2 will be treated as the seasonal emergency rating of the circuit breaker.

Data Dictionary for Electric System Security Data

Introduction

The data and terms described here are intended as a definition and clarification of the electric system security data required by SPP Criteria 5. The definitions herein were derived from the requirements listed in Appendix 4B of NERC Policy 4, Section B, *System Coordination – Operational Security Information* and the additional data required by Southwest Power Pool. Each term is defined and its current or expected method of exchange is specified.

Assumptions and Standard Conventions

1. All presently telemetered values must be supplied as specified in this appendix. Requests for real-time data not presently telemetered must follow the NERC data request process.
2. Control Areas that cannot meet some portion of the requirements of this appendix may seek a waiver from the Operating Reliability Working Group (ORWG). The request for waiver shall indicate, if appropriate, when the Control Area will comply with the requirement for which the waiver is being sought.
3. It is assumed that Ampere measurements are used only for thermal limits calculations, and therefore, only an absolute value is required.
4. With respect to sign convention, positive is expected to be out of the bus and out of the generating unit at the point of measurement. The ISN Data Definition File, UsageMultiplier value must be defined as a negative value (normally –1.0) if the measurement does not follow this convention.
5. The ICCP standard does not discuss the scaling of analog quantities. Conversion to correct units is the responsibility of the originating host. Where that is not possible, the UsageAdder and UsageMultiplier values on the ISN Data Definition File must define the appropriate scaling factors. Sign (direction) conversion is the responsibility of the receiver.
6. ICCP data will be exchanged via the following blocks:
    1. BLOCK 1: Periodic dataset at the defined periodicity
    2. BLOCK 2: Exception triggered dataset, Report by Exception, 5 second buffering period, 10 minute integrity (full dataset) transmission.
7. The acceptable values assigned to the indication status point are prescribed in IEC 870-6-802 *TASE.2 Object Models*, Section 8.1 Use of IndicationPoint Models. Specifically, the following values are expected:

    0 Between
    1 Tripped, Open, Off, Out-of-service
    2 Closed, On, In-service

    If the sender of the data cannot accommodate the above standard, documentation of the possible values and their meaning must be provided to SPP.
8. All measurements to be exchanged via ICCP will be defined in the NERC ISN Data Definition File. The ISN Data Definition File will be updated per the following criteria:
    - At least 7 calendar days prior to a planned topology change but not effective until notified by company representative.

- Within 20 business days, upon request of SPP.
- Six months elapsed since last submitted.

9. Each Control Area shall provide topological updates, including System One-Line Diagrams, in a format acceptable to SPP. The topological updates will be provided per the following criteria:
   - At least 7 calendar days prior to a topology change becoming effective (i.e. energizing the revised system).
   - Within 20 business days, upon request of SPP.

   If the update cannot be provided within the time frames above, the Control Area shall advise SPP staff and provide an estimate of when the information will be available.
10. Each Control Area shall provide model data updates, such as line and transformer ratings (for the EMS model), SCADA limits (used for display/operator alarming), line characteristics, transformer characteristics, and unit characteristics in a format acceptable to SPP. The model data updates will be provided per the following criteria:
    - At least 7 calendar days prior to the updated system model data becoming effective (i.e. energizing the revised system).
    - Within 20 business days, upon request of SPP.

    If the update cannot be provided within the time frames above, the Control Area shall advise SPP staff and provide an estimate of when the information will be available.
11. Gross or net generation measurements (MW and MVAR) can be accepted. If gross measurements are supplied, the station auxiliary measurements must also be supplied so that net measurements can be derived.

Node Connectivity Requirement

SPP operates ICCP nodes at both the primary and disaster recovery sites. Both the primary and disaster recovery site ICCP servers feed real-time data to the primary and disaster recovery site Energy Management Systems. To ensure maximum availability of ICCP data required for operating reliability, the following connectivity requirements are stipulated:

- SPP members are required to configure their ICCP servers to connect to the SPP primary and disaster recovery sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.

- SPP will normally reference the same ICCP Object ID from both nodes when reading member data, thus imposing no additional maintenance workload upon the member companies.

- Members operating a disaster recovery site may choose to concurrently serve data from that site. In that instance, SPP will configure the primary ICCP node to communicate with the member's primary site node and will configure the disaster recovery site ICCP node to communicate with the member disaster recovery site node. This is required per the TASE.2 standard.

- SPP will configure the disaster recovery site ICCP nodes to serve data to member sites using a separate and distinct ICCP Object ID in order to permit them to concurrently read

operating reliability data from redundant nodes. This is required per the TASE.2 standard.

Change History

June 6, 2001: Modified submission interval criteria for Unit Commitment Report.

March 11, 2002: Added update periodicity for ISN Data Definition File. Added requirement to require submission of System One-Line and Overview diagrams.

February 10, 2004: Changed references from Security Working Group (SWG) to Operating Reliability Working Group (ORWG). Added reference to the reporting requirements of the NERC Cyber Security Standard and removed references to the InfraGard and SCIS reporting mechanisms. Added requirement for concurrent connection and data transfer from member ICCP nodes to the SPP primary and backup site ICCP nodes.

March 12, 2004: Clarified the requirement to submit topology change documentation.

March 26, 2004: Added requirement to submit model data updates

June 30, 2004: Revised timing requirements for submitting ISN Data Definition Files, topology and system model updates. Replaced Unit Commitment Report with Resource Plan

April 4, 2005: Replaced Special Operating Security Limits with System Operating Limits and added reporting requirements.

June 4, 2007: Removed temperature reporting requirements from Hourly Load Report

September 6, 2007: Revised Inadvertent Accounting Report to reflect reporting via NERC Inadvertent Monitoring Application.

Data Prescribed by NERC Appendix 4B

Transmission Data

Status

Description

Status of the switching devices (breakers, switches, disconnects) at each end of a transmission line. Possible values are Open and Closed for two-state devices and Open, Closed, and Between for three state devices.

Exchange Mechanism

ICCP Block 2.

Transmission Facility Loading (MW or Ampere Loadings)

Description

Instantaneous power flow (MW and MVar) or instantaneous current flow (ampere loading) on the transmission facility. If ampere loading is provided, voltage measurement on the same facility must also be provided.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

MVA Capability

Description

MVA limit for transmission facilities. This may be either a static or dynamic limit.

Exchange Mechanism

Dynamic limits: ICCP Block 1, 30 second maximum periodicity.
Static limits: Network model exchange or other mechanism to be defined.

Transformer Tap Setting

Description

Predefined, fixed positions on one or both sides of a transformer. Each Tap position represents a specific voltage value. (i.e. changing a Tap Position changes the voltage.) There is no standard numbering scheme for the tap position. For example, some utilities number beginning at 0, others at 1. Other utilities refer to the nominal position as position 0, with positive integers for positions above nominal, and negative integers for positions below nominal. Still other utilities use turns ratio and not position notations. Documentation defining the possible values and their meaning must be provided to SPP, either as part of the exchanged network model or as a separate document.

Exchange Mechanism

Telemetered or derived tap positions: ICCP Block 1, 30 second maximum periodicity.
Non-telemetered and no-load tap information: Network model exchange or other mechanism to be defined.

Transformer Phase Angle Setting

Description

Represents the Phase Angle between the current and voltage. (i.e. changing the Phase Angle changes the power.) The angle settings can typically vary between -90 and +90. The unit of measurement is Degrees.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

Key Voltage

Description

Instantaneous voltage measurement for all telemetered locations on the transmission network. Unit of measurement is kV. PerUnit, 100Base, 120Base, etc. voltages must be converted to simple kV readings by the originator or, if not possible, the appropriate scaling factors must be defined.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

Generator Data

Status

Description

Status of the generator as telemetered, or as derived from the status of the breaker associated with the generator unit. Possible values are In-service, Out-of-service and Between, or On, Off and Between.

Exchange Mechanism

ICCP Block 2

MW Capability

Description

Limit on the gross or net MW output of a generator unit. This value may be either a static or dynamic limit.

Exchange Mechanism

Dynamic limits: ICCP Block 1, 30 second maximum periodicity.
Static limits: Network model exchange or other mechanism to be defined.

MVAR Capability

Description

MVAR Capability Curve for a generating unit.

Exchange Mechanism
Network model exchange or other mechanism to be defined.

MW Output
Description
Instantaneous measurement of the gross or net real output power from the generator.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

MVAR Output
Description
Instantaneous measurement of the gross or net imaginary output power from the generator.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Status of Automatic Voltage Control Facilities
Description
Instantaneous telemetered or derived status of automatic voltage regulators, and if they exist, the statuses of fast acting exciters and stabilizers. Possible values are In-service, Out-of-service, and Between, or On, Off, and Between.

Exchange Mechanism
ICCP Block 2

Operating Reserve

MW Reserve Available Within Ten Minutes
Description
The amount of additional power that can be made available to the system within 10 minutes, as defined in SPP Criteria 6.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Control Area Demand

Instantaneous Control Area Demand
Description
Instantaneous calculation of the generation minus actual interchange for the control area. The unit of measurement is MW.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Interchange

Instantaneous Actual Interchange With Each Control Area

Description
Instantaneous reading of the MW flow between control areas.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Current Interchange Schedules With Each Control Area By Individual Interchange Transaction

Description
Current scheduled MW flows between control areas, and may include interchange identifiers and reserve responsibilities.

Exchange Mechanism
Electronic Tagging.

Interchange Schedules For the Next 24 Hours

Description
Interchange schedules with each control area by individual interchange transaction for the period encompassing the next hour to 24 hours into the future.

Exchange Mechanism
Electronic Tagging.

Area Control Error and Frequency

Instantaneous Area Control Error

Description
Instantaneous measurement of the area control error. Unit of measurement is MW. Value may be positive or negative.

Exchange Mechanism
ICCP Block 1, 30 second maximum periodicity.

Clock Hour Area Control Error

Description

Instantaneous Area Control Error averaged since the start of the current hour. This value may be positive or negative. Unit of measurement is MW.

Exchange Mechanism

This measurement is NOT required by SPP.

System Frequency At One or More Locations in the Control Area

Description

Instantaneous reading of the actual frequency in Hz. This is not the deviation from a value (nominally 60 Hz).

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

Other Operating Information

System Operating Limits (SOLs)

Description

Notification of new or revised SOLs.

Exchange Mechanism

Written notification at least a calendar day prior to the effective date of planned SOLs. Any deviation from planned SOLs in real-time will be communicated by voice or telemetry.

Forecast of Operating Reserve at Peak, and Time of Peak for Current Day and Next Day

Description

Estimate of the operating reserve at the time of peak demand. Unit of measurement is MW. The time is the local clock time, with time zone specified, for the peak demand.

Exchange Mechanism

Load and Capability Report (requires modification to include time of peak).

Forecast Peak Demand for Current Day and Next Day

Description

Estimate of the peak demand for the day. Unit of measurement is MW.

Exchange Mechanism

Load and Capability Report.

Forecast Changes in Equipment Status

Description

Notification of expected changes in availability of equipment, or special protection schemes, such as equipment being placed into service or taken out of service.

Exchange Mechanism

Generation and Transmission Outage Reports.

New Facilities in Place

Description

Notification of new equipment being placed into service.

Exchange Mechanism

To be determined.

New or Degraded Special Protection Systems

Description

Notification of changes to the status of special protection schemes and systems.

Exchange Mechanism

To be determined.

Emergency Operating Procedures in Effect

Description

Notification of Emergency conditions and procedures and expected duration. This may also include Transmission Loading Relief states, Energy Emergency Alerts, and relevant information such as action taken or planned.

Exchange Mechanism

IDC, ARS, and other mechanisms to be determined.

Severe Weather, Fire, or EarthQuake

Description

Notification of severe weather conditions such as hurricanes, tornadoes, and severe thunder storms. May also include tornado and severe weather warnings and watches, and solar magnetic disturbance alerts. Also includes notification of earthquakes, and fires that affect or could potentially affect the power system operation.

Exchange Mechanism

To be determined.

Multi-site Sabotage

Description

Notification of cases of sabotage to power system equipment at multiple sites.

Exchange Mechanism
NIPC/NERC IAW Reporting Procedures and the NERC Cyber Security Standard.

Additional Operational and Topology Data Required by SPP

Scheduled Base Frequency

Description

Instantaneous reading of the scheduled (base) frequency in Hz. This is not the deviation from a value (nominally 60 Hz). If this value is only valid during periods of time correction, then a status indication value must also be supplied to indicate whether time correction is in effect or not.

Exchange Mechanism

Scheduled Base Frequency: ICCP Block 1, 30 second maximum periodicity.
Time Correction status: Block 2.

Scheduled Net Interchange With Each Control Area

Description

Scheduled net MW flow between control areas.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

Instantaneous Actual Total Net Interchange

Description

Instantaneous total net MW flow into or out of the Control Area.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

Scheduled Total Net Interchange

Description

Total scheduled MW flow into or out of the Control Area.

Exchange Mechanism

ICCP Block 1, 30 second maximum periodicity.

CPS Report

Description

Monthly NERC reporting requirement for each Control Area. The report includes CPS1 and CPS2 data reporting.

Exchange Mechanism

SDA or Web Interface, reported to SPP no later than the 10th of the month for the previous month.

Inadvertent Accounting Report

Description

Monthly NERC reporting requirement for each Balancing Authority.

Exchange Mechanism

Reported to SPP, via the NERC Inadvertent Monitoring Application, no later than the 10th of the month for the previous month.

AIE Report

Description

NERC reporting requirement when an AIE report is requested for each Control Area.

Exchange Mechanism

SDA or Web Interface, submitted upon request.

Hourly Load Report

Description

Historical load reporting required from each Control Area for SPP reporting requirements. Hour by hour actual loads are required.

Exchange Mechanism

SDA or Web Interface. Reports may be made daily, weekly, or monthly, so long as the previous month has been completely reported by the 15th of the current month.

Resource Plan

Description

Resource plans for generating facilities within the SPP region to be submitted by SPP members for the current day and next 6 days. An hourly MW plan must be submitted. The plan may be submitted on a unit-by-unit or plant-by-plant basis as the unit or plant is modeled in the SPP EMS. For each unit and for each hour the following information must be submitted: Resource Status, Planned MW, Minimum Operating Limit, and Maximum Operating Limit. Additionally, Ramp Rate may be submitted. The current day update must take into account control area load and all known interchange transactions. The next 6 days update must take into account control area load and firm transactions.

Exchange Mechanism

The next 6 days update must be submitted by 11:00 Central Time daily to the SPP FTP server using the SPP-defined XML format. The current day update must be submitted by 7:00 a.m. Central Time daily to the SPP FTP server using the SPP-defined XML format.

Load Forecast Report

Description

Hourly forecast / actual integrated load, in MW, for the prior, current, and next six days. Prior day actual loads are mandatory. Current and next six day forecast loads are requested. If the current and future day forecast is not supplied, a forecast will be derived from previously reported actual loads.

Exchange Mechanism

SDA or Web Interface, submitted daily.

System One-Line Diagrams

Description

This diagram shows the detailed generation or transmission substation topology including switching elements, transformers, reactive devices, generation, and load withdrawal points.

Exchange Mechanism

Hard copy or electronic version in an SPP-compatible format, submitted per the requirements stated in the *Assumptions and Standard Conventions* clause of this appendix. Acceptable electronic submissions include Autocad drawing files and Adobe Acrobat files in an SPP acceptable version. Documentation shall accompany electronic submittals identifying the actual changes being made. Hard copy submissions shall consist of two copies of each document with the changes clearly annotated.

Overview Diagrams

Description

A sub-control area or control area “world” map reflecting the substations and network connectivity. Substation detail is not required in the Overview diagram.

Exchange Mechanism

Hard copy or electronic version in an SPP-compatible format, submitted annually.

Appendix 8

Southwest Power Pool Generator Owner/Operator Excitation System Summary Report

Instructions: Generator Owner/Operator shall fill out summary information for all units under your control concerning the number of hours the Excitation System was not operated in Automatic Voltage Control Mode.

Generator Owner/Operator	
Month Reporting Data	
Contact Name	
Contact Phone	

Station	**Unit #**	**# Hours Excitation System not operated in Automatic Voltage Control Mode**

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Generator Unit Excitation System Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of events of a particular generating unit's excitaton system not being operated in automatic voltage control mode.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date (unit not operated in automatic mode)	**Unit #**	**Reason unit's excitation system was operated out of automated voltage control mode**

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool Generator Owner/Operator Voltage Schedule Requirements

Instructions: Control Area Operator shall specify voltage schedule to be maintained by each Generator Owner/Operator's units at a specified bus.

Generator Owner/Operator	
Control Area	
Voltage Schedule Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Station	**Unit #**	**Specified Voltage**	**Specified Bus**

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool Generator Unit Voltage Schedule Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of periods in which particular generating units did not adhere to control area's prescribed voltage schedule. If event was approved by control area operator, please attach written approvals.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date	**Duration (hr:min)**	**Reason unit did not adhere to voltage schedule**	**Approved (yes/no)**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Control Area's List of Exempt Generators

Instructions: Control Area Operator shall list units in their area of responsibility that are exempt from following prescribed Control Area Voltage Schedules.

Control Area Operator	
Last Updated	
Contact Name	
Contact Phone	

Generator Owner/Operator	Generating Station	Unit

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Generator Unit Transformer Tap Setting Report

Instructions: Generator Owner/Operators shall fill out information concerning the tap settings and impedances of all GSU and AUX transformers under their control.

Generator Owner/Operator	
Generating Station	
Last Updated	
Contact Name	
Contact Phone	

GSU/AUX Transformer I.D.	**Current Tap Setting**	**Tap Setting Range**	**Transformer Impedence (OA Base)**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Generator Unit Transformer Tap Setting Change Request

Instructions: Control Area Operator shall complete information necessary to let affected Generator Owner/Operator know of needed Generator Unit Transformer settings changes.

Generator Owner/Operator	
Generating Station	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

GSU/AUX Transformer I.D.	**Current Tap Setting**	**New Tap Setting**	**Technical Justification for Tap Setting Change**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Generator Units Exempt from Tap Setting Reporting Procedures

Instructions: Generator Owner/Operators shall fill out information for all units under their control that are exempt from Transformer Tap Setting Procedures. The criteria that is met must also be documented

Generator Owner/Operator	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Generating Station	**Unit #**	**Exemption Criteria Met**

Dev. February, 2001

Appendix 8

By SPP GWG

Southwest Power Pool
Voltage Regulator Control Setting Status Report

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Date	
Contact Name	
Contact Phone	

Generating Control	**Control Setting**	**Generator Short Term Capability**	**Protective Relay Setting**
Overexcitation Limiter			
Underexcitation Limiter			
Volts/Hertz Limiter			

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Generator Governor Characteristic Reporting

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Last Updated	
Contact Name	
Contact Phone	

Governor Control	**Control Setting**
Speed Regulation	

Dev. February, 2001
By SPP GWG

Appendix 8

Southwest Power Pool
Non-Functioning Governor Controls

Instructions: Generator Owner/Operators shall fill out information for all units under their control that has a non-functioning or a blocked speed/load governor control.

Generator Owner/Operator	
Last Updated	
Contact Name	
Contact Phone	

Generating Station	**Unit**	**Governor Status (Blocked/Non-functioning)**

Dev. February, 2001
By SPP GWG

SPP Misoperation Report

Reporting Utility: _____ **Date:** _____

Contact Person:

Name	
Phone	
Fax	
E-Mail	
Address	

Equipment Category and Operating Voltage:

DME (Yes/No):	**TPS (Yes/No):**	**GCP (Yes/No):**
SPS (Yes/No):	**UFLS (Yes/No):**	**UVLS (Yes/No):**
ARL (Yes/No):		**Voltage (kV):**

Time, Equipment Location & Description:

Incident Date:	**Incident Time:**	**Time Zone:**
Relay MFGR:	**Relay Type:**	**Relay Flags:**
Substation Name/Number:	**Line/Bus/Auto/Unit Name/No.:**	**Circuit Breaker Numbers:**

Description of Misoperation/Failure:

Investigation Results:

Corrective Action:

Target Date To Complete Recommendations:

Recommendations:

Person Verifying That All Corrective Actions And Recommendations Have Been Completed:

Name:	**Title:**	**Date:**

Note: Equipment categories include DME – Disturbance Monitoring Equip, TPS – Transmission Protection Systems, GCP – Generator Control & Protection, SPS – Special Protection Systems, UFLS –

Appendix 9 – Response Factor Thresholds June 2, 2004

Factor	Short-term	Long-term *	Date Approved	Comments
PTDF	3%	3%	4/27/2004	
OTDF	3%	3%	4/27/2004	
PTVF	0.02 p.u.	0.02 p.u.	12/12/2001	
TRM		0%	12/12/2001	See SPP website for short-term TRM

* Long-term factors apply to all elements above 60kV.

Appendix 10: Unit Reactive Limits (Lead and Lag) Verification FORM

General Information

Unit Operating Entity _____ Contact person _____

Plant _____ Unit No.:_____

Location (State): _____ Transmission Modeler: _____

Test/Verification Details

Instructions:

Maximum leading and lagging reactive test/verification should be conducted under conditions that are likely to induce reactive response that approaches the unit's maximum capability, as further described in Criteria 12.1.6.5.2.

The procedures for the test/verification are specified in Criteria 12.1.6.5.3.

Upon completion of a test/verification (which includes data points for both leading or lagging capability), this completed form shall be submitted to the SPP Member that is responsible for modeling the unit in power flow and stability models.

***MAXIMUM LAGGING* (Unit injects VARs) (4): Date of Test: _____**

Gross Generation	Auxiliary Load	Net Gen. @ POI (1)	Generator Terminal Voltage	Transmission bus Voltage @ POI (1)
_____MW	_____MW	_____MW	Ph.1_____kV (5)	Ph.1_____kV
_____MVAR	_____MVAR	_____MVAR	Ph.2_____kV	Ph.2_____kV
			Ph.3_____kV	Ph.3_____kV

Data point at Near Maximum Rated MW.

***MAXIMUM LEADING* (Unit absorbs VARs) (4): Date of Test: _____**

Gross Generation	Auxiliary Load	Net Gen. @ POI (1)	Generator Terminal Voltage	Transmission bus Voltage @ POI (1)
_____MW	_____MW	_____MW	Ph.1_____kV (5)	Ph.1_____kV
_____MVAR	_____MVAR	_____MVAR	Ph.2_____kV	Ph.2_____kV
			Ph.3_____kV	Ph.3_____kV

Data point at Near Maximum Rated MW.

VERIFICATION METHOD:

❑ Operational Data ❑ Engineering Analysis

❑ Commissioning Data ❑ Testing/Validating

TEST PERFORMED:

❑ Maximum Leading Reactive ❑ Maximum Lagging Reactive

VERIFICATION CONDITIONS:

Date: _____

Start Time: _____ Stop Time: _____

Ambient Air Temperature (°F): _____ (2)

GENERATOR STEP-UP NAMEPLATE DATA:

Fixed Tap Setting _____kV Impedance: _____ % Capability: _____MVA (3)

GENERATOR NAMEPLATE DATA:

Maximum Gross Dependable Unit Generation: _____MW

Maximum Net Dependable Unit Generation: _____MW

Rated Power Factor: _____

Unit Rating: _____ MVA

Nominal Terminal Bus Voltage: _____ kV

Abnormal Conditions at Time of Test:_____

_____

_____

FACTORS THAT LIMITED REACTIVE CAPABILITY DURING TEST:

❑ Maximum Generator Voltage with Auxiliary loads

❑ Maximum Generator Voltage without Auxiliary loads

❑ Minimum Generator Voltage with Auxiliary loads

❑ Minimum Generator Voltage without Auxiliary loads

❑ Main transformer capability plus Auxiliary loads

❑ Transmission system constraint

❑ Steady State Stability Limit

❑ Maximum Gross MW capability

❑ Minimum Gross MW capability

❑ Minimum Excitation Limiter

❑ Loss of Field Relay

❑ Other: _____

_____

SUBMITTAL:

Date submitted to SPP Control Area Authority Representative: _____

NOTES:

(1) Point of Interconnect.
(2) Degrees Fahrenheit if limiting, outside air or generator air.
(3) Actual tap setting – not nominal tap setting.
(4) Maximum Leading and Maximum Lagging test/verification may be conducted at different times of the year. VARs – Volt-Amps reactive
(5) kV – kilovolt which is equal to 1000 volts.