CALCULATION NOTE COVER SHEET

Section To Be Completed By Author(s):

Calc-Note Number: QC-CN-93-003 **Revision Number:** 0

Title:

POWER RECOVERY PROBABILITIES FOR QUAD CITIES IPE

Project: QUAD CITIES IPE
Shop Order: N\A

Purpose: TO DOCUMENT THE SOURCE OF THE PROBABILITIES USED FOR TWO NODES IN THE QUAD CITIES LOSS OF OFFSITE POWER AND STATION BLACKOUT PLANT RESPONSE TREES.

Results Summary: THE QUAD CITIES STATION IS CONSIDERED TO BE IN THE OFFSITE POWER RECOVERY CLUSTER GROUP #2. ACTUAL PROBABILITIES OF NOT RECOVERING POWER AT SPECIFIC TIMES ARE SHOWN IN SECTION 4.

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CALC-NOTE NUMBER: QC-CN-93-003 REV. 0

CALCULATION NOTE METHODOLOGY CHECKLIST

CHECKLIST TO BE COMPLETED BY AUTHOR(S): (CHECK APPROPRIATE RESPONSE)

1.	Is the Subject and/or the Purpose of the Design Analysis Clearly Stated?	(YES) NO
2.	Are the Required Inputs and Their Sources Provided?	(YES) NO N/A
3.	Are the Assumptions Clearly Identified and Justified?	(YES) NO N/A
4.	Are the Methods and Units Clearly Identified?	(YES) NO N/A
5.	Are the Results of Literature Searches, if Conducted, and Other Background Data provided?	(YES) NO N/A
6.	Are all the Pages Sequentially Numbered and Identified by the Calculation Note Number?	(YES) NO
7.	Is the Project or Shop Order Clearly Identified?	YES NO (N/A)
8.	Has the Required Computer Calculation Information Been Provided?	YES NO (N/A)
9.	Were the Computer Codes Used Under Configuration Control?	YES NO (N/A)
10.	Are the Results and Conclusions Clearly Stated?	(YES) NO
11.	Were Approved Design Controlled Practices Followed Without Exception?	(YES) NO

NOTE: IF 'NO' TO ANY OF THE ABOVE, PAGE NUMBER CONTAINING JUSTIFICATION:__________

TABLE OF CONTENTS

1.0 INTRODUCTION

The purpose of this calculation note is to document the source of the probabilities used for two nodes in the Quad Cities Loss of Offsite Power and Station Blackout Plant Response Tree notebooks (References 1 and 2). The two nodes in question are:

ROP1 - Recovery of Offsite Power in Time to Preclude Core Damage (LOOP)
ROP2 - Recovery of Offsite Power in Time to Preclude Core Damage (SBO)

The methodology used to determine these probabilities is contained in this document and is based on the information found in NUREG-1032 "Evaluation of Station Blackout Accidents at Nuclear Power Plants" (Reference 3).

The steps to determine these probabilities include:

- Determine the "Offsite Power Cluster Group" that Quad Cities should be included in by implementing the selection criteria found in NUREG-1032.
- Determine the probability of recovering power in time to prevent core damage (ROP1/ROP2) using the frequency distributions contained in NUREG-1032.

Each of these steps will be discussed in detail in the following sections.

2.0 DETERMINATION OF POWER CLUSTER SUBGROUPS

The Offsite Power Cluster Grouping is an attempt to account for any relationship between switchyard design characteristics, local weather, power recovery procedures, and the duration of loss of offsite power events at a given plant. The methodology used to determine the appropriate Offsite Power Cluster Group is based on the selection criteria found in Tables A.2, A.3, A.6 and Tables A.8 through A.11 of NUREG-1032. The Offsite Power Cluster

Group is determined by the unique combination of four subgroups. These subgroups, defined by grid design and local weather, are shown below:

1. Switchyard Configuration Group (I1, I2, I3)
2. Grid Reliability/Recovery Group (G1, G2, G3, G4)
3. Severe Weather-Induced Loss of Offsite Power Frequency/Recovery Group (SR1, SR2, SR3, SR4, SR5, SR6, SR7, SR8, SR9, SR10)
4. Extremely Severe Weather-Induced Loss of Offsite Power Frequency Group (SS1, SS2, SS3, SS4, SS5)

Two factors, grid and switchyard design, are potentially significant with regard to frequency and duration of loss of offsite power events. The impact of these design factors is determined by the blend of responses (yes/no) to the following statements. The unique blend of yes and no responses define the impact of these features and the subsequent Switchyard Configuration Group to which the plant belongs.

A. Independence of offsite power sources to the nuclear plant.

1. All offsite power sources are connected to the plant through one switchyard. **YES**
2. All offsite power sources are connected to the plant through two or more switchyards, and the switchyards are electrically connected. **NO**
3. All offsite power sources are connected to the plant through two or more switchyards or separate incoming transmission lines, but at least one of the AC sources is electrically independent of the others. **NO**

B. Automatic and manual transfer schemes for the Class 1E buses when the normal source of AC power fails and when the backup sources of offsite power fail.

1. If the normal source of AC power fails, there are no automatic transfers and there is one or more manual transfers to preferred or alternate offsite power sources. **NO**

2. If the normal source of AC power fails, there is one automatic transfer but no manual transfers to preferred or alternate offsite power sources. **NO**

   a. All of the Class 1E buses in a unit are connected to the same preferred power source after the automatic transfer of power sources. **YES**

   b. The Class 1E buses in a unit are connected to separate offsite power sources after the automatic transfer of power sources. **NO**

3. After loss of the normal AC power source, there is one automatic transfer. If this source fails, there may be one or more manual transfers of power sources to preferred or alternate offsite power sources. **YES**

   a. All of the Class 1E buses in a unit are connected to one preferred power source after the first automatic transfer. **YES**

   b. The Class 1E buses in a unit are connected to separate offsite power sources after the first automatic transfer. **NO**

4. If the normal source of AC power fails, there is an automatic transfer to a preferred source of power. If this preferred source of power fails, there is an automatic transfer to another source of offsite power. **NO**

   a. All of the Class 1E buses in a unit are connected to the same preferred power source after the first automatic transfer. **NO**

   b. The Class 1E buses in a unit are connected to separate offsite power sources after the first automatic transfer of power source. **NO**

The responses to the above statements are based on information contained in the Electric Power Systems Notebook (Reference 4) and show that Quad Cities falls into Switchyard Configuration Group I3. All group designations based on design factors are shown in Table 1 of Appendix A.

2.1 Grid Reliability/Recovery Group

The Grid Reliability/Recovery Group combines into a single factor the inherent reliability of the local power grid and the ability of the plant to rapidly recover from the loss of power.

From the Quad Cities Initiating Events Notebook (Reference 5), the frequency of grid related losses is 2.7E-3 per year. Quad Cities has never experienced a grid related loss of offsite power. NUREG-1032 implies use of a grid loss frequency of 1E-2 per year if no loss of power events have occurred at the individual site. However, use of either frequency will place Quad Cities in Grid Group G1. Table 2 of Appendix A shows the relationship of grid loss frequency to Grid Group.

The next step in determining the Grid Reliability/Recovery Group is to identify the recovery group. The recovery group qualitatively identifies the plant's ability to recover power within 1/2 hour following a grid blackout. The plant must have the capability and procedures to recover offsite (non-emergency) AC power to the site within 1/2 hour following a grid blackout to be considered in the R1 group. By default, all other plants not in the R1 group are contained in the R2 group. Quad Cities does not have specific procedures in place for recovering power in this time frame and therefore falls into the R2 recovery group. This combination of factors leads to a Grid Reliability/Recovery Group of GR5 as identified by Table 3 of Appendix A.

2.2 Severe Weather/Recovery Group

The severe weather/recovery group combines into a single factor the likelihood of loss of offsite power due to severe weather events with the ability of the plant to recover from the event in a rapid manner. From the Quad Cities Initiating Events Notebook, the frequency of severe weather related loss of offsite power events at the Quad Cities station is 8.1E-3 per year. This frequency, in combination with the recovery group R2 identified earlier in section 2.1, defines a Severe Weather/Recovery Group of SR7. Tables 4 and 5 in Appendix A show the manner in which severe weather frequency and plant recovery ability are grouped to arrive at the SR7 group designation.

2.3 Extremely Severe Weather Loss of Offsite Power Frequency Group

This group is determined strictly by the frequency of extremely severe weather, postulated in this case. This event consists of losses of offsite power caused by extreme weather such as hurricanes, very high winds (greater than 125 mph) and major damage to switchyards due to tornado strikes. Restoration of offsite power following these events is assumed to require at least 24 hours. The Quad Cities Initiating Events Notebook gives a frequency of 2E-4 per year for this type of event. The group designators associated with each occurrence frequency range are shown in Table 6 of Appendix A. With an occurrence frequency of 2E-4, Quad Cities is considered to be in group SS1.

3.0 DETERMINATION OF OFFSITE POWER CLUSTER GROUP

The subgroups previously defined in section two permit determination of the offsite power cluster group. These subgroups I3, G1, SR7 and SS1 can be inserted into the matrix shown in Table 7 of Appendix A to determine the proper cluster group. The results of this process show that Quad Cities should be included in Offsite Power Cluster Group 2.

4.0 PROBABILITY OF NOT RECOVERING POWER AT TIME X (ROP1/ROP2)

NUREG-1032 gives frequency distributions for durations of loss of offsite power events for each of the cluster groups (table A.11 of Reference 3). The probability of not recovering power at each hour was derived using the median values of the frequency distribution data contained in this table. The frequency at each time interval was divided by the frequency at time = 0 hours to normalize the values and thus render probabilities. Since the information contained in NUREG-1032 did not have values for every hour, values for each missing hour through 16 hours were obtained by using log extrapolations, which provide a good fit to the to the loss of offsite power frequency duration curves presented in Figure A.15 of NUREG-1032. The values for each of the intermediate hours not given was estimated by the

following equation:

$$P=10^{\frac{LOG(X)+LOG(Y)}{2}}$$

where x = probability at previous hour given
and y = probability at the next succeeding hour given

This equation gives a value for a point midway between two known times x and y. The results of applying this equation can then be used again to determine a new intermediate value and the equation reapplied until all the unknown values are determined. This information is summarized in the following table for Offsite Power Cluster Group 2 for events of up to 16 hours duration.

DURATION (HR)	Loss of offsite power frequency (Table A.11 of NUREG-1032)		Probability of not recovering power
	Freq	Normalized	
0	0.1040	1.000E+00	1.000E+00
1/2	N/A	N/A	6.068E-01
1	N/A	N/A	3.682E-01
2	0.0141	1.356E-01	1.356E-01
3	N/A	N/A	9.553E-02
4	0.0070	6.731E-02	6.731E-02
5	N/A	N/A	5.852E-02
6	N/A	N/A	5.088E-02
7	N/A	N/A	4.424E-02
8	0.0040	3.846E-02	3.846E-02
9	N/A	N/A	3.569E-02
10	N/A	N/A	3.312E-02
11	N/A	N/A	3.074E-02
12	N/A	N/A	2.852E-02
13	N/A	N/A	2.647E-02
14	N/A	N/A	2.456E-02
15	N/A	N/A	2.280E-02
16	0.0022	2.115E-02	2.115E-02

5.0 REFERENCES

1. Loss of Offsite Power Event Tree Notebook, Quad Cities Nuclear Power Station Units 1 and 2, prepared by IPEP, August 1993, Rev. 0.

2. Station Blackout Event Tree Notebook, Quad Cities Nuclear Power Station Units 1 and 2, prepared by IPEP, date and rev. to be provided.

3. Baranowsky, P.W., et. al., "Evaluation of Station Blackout Events at Nuclear Power Plants", U.S. NRC Report NUREG-1032, June 1988.

4. Electric Power Systems Notebook, Quad Cities Nuclear Power Station Units 1 and 2, prepared by IPEP, date and rev. to be provided.

5. Initiating Events Notebook, Quad Cities Nuclear Power Station Units 1 and 2, prepared by IPEP, date and rev. to be provided.

APPENDIX A

TABLE 1

DEFINITION OF SWITCHYARD CONFIGURATION GROUPS	
GROUP	FACTOR
I1	A1, A2, or A3 and B4
I2	A1 or A2 and B2b or B3
I3	A1 or A2 and B1 or B2a

TABLE 2

DEFINITION OF FREQUENCY OF GRID GROUPS	
GROUP	FREQUENCY OF GRID LOSS PER SITE YEAR
G1	less than 1.67E-2
G2	1.67E-2 to 5.0E-2
G3	5.0E-2 to 0.167
G4	equal to or greater than 0.167

TABLE 3

DEFINITION OF GR GROUPS		
FREQUENCY GROUP	RECOVERY GROUP	GRID RELIABILITY/RECOVERY GROUP (GR)
G1	R1	GR1
G2	R1	GR2
G3	R1	GR3
G4	R1	GR4
G1	R2	GR5
G2	R2	GR6
G3	R2	GR7

TABLE 4

DEFINITION OF FREQUENCY OF SEVERE-WEATHER GROUPS	
GROUP	FREQUENCY PER SITE YEAR
S1	less than 3.0E-3
S2	3.0E-3 to 1.0E-2
S3	1.0E-2 to 3.0E-2
S4	3.0E-2 to 0.1
S5	0.1 to 0.33

TABLE 5

DEFINITION OF SR GROUPS		
FREQUENCY GROUP	RECOVERY GROUP	SEVERE-WEATHER/RECOVERY GROUP
S1	R1	SR1
S2	R1	SR2
S3	R1	SR3
S4	R1	SR4
S5	R1	SR5
S1	R2	SR6
S2	R2	SR7
S3	R2	SR8
S4	R2	SR9
S5	R2	SR10

TABLE 6

DEFINITION OF EXTREMELY SEVERE WEATHER-INDUCED GROUPS	
GROUP	FREQUENCY PER SITE YEAR
SS1	less than 3.0E-4
SS2	3.04E-4 to 8.3E-4
SS3	8.3E-4 to 3.0E-3
SS4	3.0E-3 to 1.0E-2
SS5	greater than or equal to 1.0E-2

TABLE 7

CLASSIFICATION OF OFFSITE POWER CLUSTER GROUPS				
CLUSTER GROUP	I	GR	SR	SS
1	1,2 1,2 1,2	1,3,5 1,3,5 1,3,5	1,2,6,7 1,6 3	1,2 3 1,2
2	1,2 1,2 1,2 1,2 3 3 3 3	1,3,5 1,3,5 1,3,5 1,3,5 1,3,5 1,3,5 1,3,5 1,3,5	8 4 2,3,7 1,6 1,2,6,7 3,8 3 4	1,2,3 1-4 3,4 4 1-4 1,2 3,4 1-4
3	same as cluster 2 and 1	7	same as cluster 2 and 1	same as cluster 2 and 1
4	1,2,3	1,3,5,7	10	1-5

NUREG 1032 DISTRIBUTIONS
PROBABILITY OF NOT RECOVERING POWER

	CLUSTER GROUPS				
TIME	1	2	3	4	5
0	1.000E+00	1.000E+00	1.000E+00	1.000E+00	1.000E+00
1	2.481E-01	3.682E-01	4.105E-01	4.663E-01	6.622E-01
2	6.154E-02	1.356E-01	1.685E-01	2.174E-01	4.385E-01
3	4.267E-02	9.553E-02	1.198E-01	1.668E-01	3.567E-01
4	2.959E-02	6.731E-02	8.509E-02	1.279E-01	2.902E-01
5	2.463E-02	5.852E-02	6.648E-02	1.184E-01	2.393E-01
6	2.050E-02	5.088E-02	5.194E-02	1.097E-01	1.974E-01
7	1.706E-02	4.424E-02	4.058E-02	1.016E-01	1.628E-01
8	1.420E-02	3.846E-02	3.170E-02	9.403E-02	1.343E-01
9	1.273E-02	3.569E-02	2.725E-02	8.462E-02	1.142E-01
10	1.141E-02	3.312E-02	2.343E-02	7.615E-02	9.717E-02
11	1.023E-02	3.074E-02	2.014E-02	8.265E-02	7.030E-02
12	9.167E-03	2.852E-02	1.731E-02	6.167E-02	7.030E-02
13	8.217E-03	2.647E-02	1.488E-02	5.550E-02	5.979E-02
14	7.365E-03	2.456E-02	1.279E-02	4.994E-02	5.086E-02
15	6.601E-03	2.280E-02	1.100E-02	4.494E-02	4.326E-02
16	5.917E-03	2.115E-02	9.455E-03	4.044E-02	3.679E-02
17	5.304E-03	1.963E-02	8.128E-03	3.640E-02	3.130E-02
18	4.754E-03	1.822E-02	6.987E-03	3.275E-02	2.662E-02
19	4.261E-03	1.691E-02	6.007E-03	2.948E-02	2.264E-02
20	3.820E-03	1.569E-02	5.164E-03	2.652E-02	1.926E-02
21	3.424E-03	1.456E-02	4.439E-03	2.387E-02	1.638E-02
22	3.069E-03	1.351E-02	3.816E-03	2.148E-02	1.393E-02
23	2.751E-03	1.254E-02	3.280E-03	1.933E-02	1.185E-02
24	2.465E-03	1.63E-02	2.820E-03	1.740E-02	1.008E-02

Attachment 4-B

QUESTION 11

11. The common cause failure values used in the IPE are lower than those typically used in other IPE/PRAs. For example, the beta factor for failure of 2 MOVs is a factor of 5 to 9 lower than the beta factor typically used and the beta factor for DGs is a factor of 10 lower than the beta factor typically used. Screening common cause data for plant specific applicability based on expert opinion is a rather questionable approach because common cause events address classes of events as opposed to specific events as typically are screened for applicability.

    (a) Please provide the justification for the low common cause factors used in the IPE.

RESPONSE TO QUESTION 11 (a)

"Common cause" describes multiple failures of functionally identical components due to a single, shared cause. Common cause analysis (CCA) evaluates the effects of these dependencies that may affect the ability of a system to prevent or mitigate a severe accident.

The Quad Cities CCA modeled common cause failures at the basic event level, employing the Multiple Greek Letter (MGL) method as defined in NUREG/CR-4780, "Procedures for Treating Common Cause Failure in Safety and Reliability Studies."

A generic common cause failure database was developed from EPRI NP-3967, "Classification and Analysis of Reactor Operating Experience Involving Dependent Events", supplemented with events from the September 1990 EPRI draft report, "A Database of Common Cause Events for Risk and Reliability Evaluations" (EPRI TR-100382).

This common cause failure database was screened to insure that the appropriate degree of temporal coincidence was present and to make it specific to Quad Cities. Because not all of the listed ("generic") failures are applicable to Quad Cities, the common cause factors were naturally reduced. The expert opinion employed in the screening process was needed to accurately determine the applicability of the data to the Quad Cities' components.

3.0 DISCUSSION

To support the generation of values for the MGL factors, a common cause database was developed. Discussions with respect to that database and the calculation of component specific conditional probabilities are contained in the sections which follow.

3.1 DATABASE DEVELOPMENT

The EPRI database includes common cause events on the following components:

COMPONENT	COMMON CAUSE EVENT DESCRIPTIONS PLG-0865 PAGE #	ADDITIONAL INDEPENDENT EVENTS
Diesel Generators	3- 6 to 3- 20	566
High Head Safety Injection Pumps	3- 33 to 3- 39	70
Residual Heat Removal Pumps	3- 42 to 3- 49	63
Containment Spray Pumps	3- 52 to 3- 59	30
Auxiliary Feedwater Pumps	3- 61 to 3- 70	131
Standby Liquid Control Pumps	3- 75 to 3- 76	3
HPCI and RCIC Pumps	3- 78 to 3- 82	94
Service Water Pumps	3- 86 to 3- 94	105
Component Cooling Water Pumps	3- 98 to 3- 98	22
HVAC Chillers	3-101 to 3-102	33
Containment Cooling & HVAC Fans	3-104 to 3-121	66
Motor Operated Valves	3-124 to 3-163	784
Standby Liquid Control Relief Valves	3-182 to 3-183	19
*Two-Stage Target-Rock Relief Valves	3-185 to 3-197	11
Electromatic Relief Valves	3-199 to 3-210	19
Check Valves	3-212 to 3-220	77
Circuit Breakers	3-223 to 3-237	98
Reactor Trip Breakers	3-241 to 3-247	47

* Eliminated from review; component not part of CECo systems.

Information provided for the EPRI database of multiple failures includes: component, plant, date, plant status, event description, failure mode, shock type, population size, and impact vector values. All events considered for inclusion in the common cause database used in this evaluation are listed in Table 1. This table indicates if the event was applicable (A) or not (N) applicable to each of the four CECo sites. If an event was deemed by the expert review panel to be not applicable, a reason was provided and recorded on the event record sheets in Appendix A.

TABLE 1: COMMON CAUSE EVENTS AND APPLICABILITY TO BYRON, BRAIDWOOD, QUAD CITIES AND LASALLE IPEs.

TYPE	ID	APPL-RATIONALE BY	BR	QC	LS	PLANT	DATE	STATUS	P/B
DG	DG -01	N-14	N-14	N-14	N-14	Peach Bottom 2	February 1978	1% Power	D
DG	DG -02	A	A	A	A	Browns Ferry 1	January 1980	Refueling	D
DG	DG -03	N-14	N-14	N-14	N-14	Zion 1	July 1974	74% Power	D
DG	DG -04	N-24	N-24	N-24	N-24	Hadam Neck	April 1968	Power	D
DG	DG -05	N-10	N-10	N-10	N-10	Cook 1	December 1977	100% Power	D
DG	DG -06	A	A	A	A	Yankee Rowe	August 1977	Refueling	D
DG	DG -07	N-07	N-07	N-07	N-07	Arkansas-1	August 1979	100% Power	D
DG	DG -08	N-07	N-07	N-07	N-07	Dresden 2	May 1973	Power	D
DG	DG -09	A	A	A	A	Salem	July 1977	Hot Standby	D
DG	DG -10	N-11	N-11	N-11	N-11	Millstone 2	May 1977	Power	D
DG	DG -11	N-24	N-24	N-24	N-24	TMI-1	March 1978		D
DG	DG -12	A-23	A-23	A-23	A-23	Quad Cities	May 1973	Power	D
DG	DG -13	N-10	N-10	N-10	N-10	Brunswick 1	January1977	32% Power	D
DG	DG -14	N-04	N-04	N-04	N-04	Dresden 2,3	September 1972	350 MWt/Cold Shutdown	D
HH	HH -01	N-33	N-33	N-33	N-33	Salem 1, 2	November 1979	Shutdown	D
HH	HH -02	N-30	N-30	N-30	N-30	Point Beach 2	September 1978	100% Power	D
HH	HH -03	N-12	N-12	N-12	N-12	Arkansas 1	January 1982	84% Power	D
HH	HH -04	N-10	N-10	N-10	N-10	North Anna 1	April 1979	Cold Shutdown	D
HH	HH -05	N-31	N-31	N-31	N-31	Robinson 2	November 1977	Startup	D
HH	HH -06	N-07	N-07	N-07	N-07	Robinson 2	July 1973	Power	D
RH	RHSI-01	N-14	N-14	N-14	N-14	Beaver Valley 1	January 1978	Power	D
RH	RHSI-02	A	A	A	A	Monticello	December 1972	Refueling	D
RH	RHSI-03	N-10	N-10	A	A	Browns Ferry 1	September 1974	Cold Shutdown	D
RH	RHSI-04	N-10	N-10	N-10	N-10	Beaver Valley 1	January 1981	Startup	D
RH	RHSI-05	N-31	N-31	A	N-31	Peach Bottom 2	April 1978	95% Power	D
RH	RHSI-06	N-10	N-10	A	A	Brunswick 1	April 1979	30%Power	D
RH	RHSI-07	A-19	A-19	A-19	A-19	Brunswick 2	April 1979	Refueling	D
CS	CS -01	N-10	N-10	N-10	N-10	Robinson 2	October 1978	100% Power	P
CS	CS -02	N-12	N-12	N-10	N-10	Oconee 2	January 1975	Startup	P
CS	CS -03	N-12	N-12	N-10	N-10	Davis Besse	January 1978	Hot Shutdown	P
CS	CS -04	N-12	N-12	N-10	N-10	Cook 2	May 1978	Hot Shutdown	P
CS	CS -05	N-12	N-12	N-10	N-10	Farley	September 1978	Hot Shutdown	P
CS	CS -06	N-12	N-12	N-10	N-10	Robinson 2	November 1977	Startup	P
CS	CS -07	A	A	N-10	N-10	Kewaunee	Oct-Dec 1977	100% Power	P
AFW	AFW -01	N-10	N-10	N-10	N-10	Kewaunee	November 1975	Shutdown	D
AFW	AFW -02	N-10	N-10	N-10	N-10	Ginna	December 1973	Critical	D
AFW	AFW -03	N-07	N-07	N-07	N-07	Turkey Point 3	May 1974	98% Power	D
AFW	AFW -04	N-10	N-10	N-10	N-10	Point Beach 1,2	April 1974	Cooldown	D
AFW	AFW -05	N-11	N-11	N-11	N-11	Zion 2	September 1981	Shutdown	D
AFW	AFW -06	N-10	N-10	N-10	N-10	Zion 1,2	November 1981	Low Power Testing	D
AFW	AFW -07	N-10	N-10	N-10	N-10	Zion 2	December 1981	Power	D
AFW	AFW -08	N-10	N-10	N-10	N-10	Arkansas 2	April 1980	0% Power	D
AFW	AFW -09	N-31	N-31	N-31	N-31	Trojan	January 1976	150 MWe	D
HPRC	HPRC-01	N-10	N-10	N-14	N-14	Brunswick 1	July 1982	55% Power	B
HPRC	HPRC-02	N-10	N-10	N-10	N-10	Browns Ferry 1	April 1980	53% Power	B
HPRC	HPRC-03	N-10	N-10	N-16	N-16	Brunswick 2	September 1980	Shutdown	B
HPRC	HPRC-04	N-10	N-10	N-14	N-14	Brunswick 2	July 1982	55% Power	B

TABLE 1 (Continued): COMMON CAUSE EVENTS AND APPLICABILITY TO BYRON, BRAIDWOOD, QUAD CITIES AND LASALLE IPEs.

		APPL-RATIONALE							
TYPE	ID	BY	BR	QC	LS	PLANT	DATE	STATUS	P/B
SWCC	SW -01	N-14	N-14	N-14	N-14	Farley 1	December 1978	100% Power	D
SWCC	SW -02	N-10	N-10	N-10	N-10	Beaver Valley 1	October 1976	Preop. Testing	D
SWCC	SW -03	N-15	N-15	N-15	N-15	Palisades	July 1982	43% Power	D
SWCC	SW -04	N-08	N-08	N-08	N-08	Pilgrim 1	December 1975	55% Power	D
SWCC	SW -05	N-08	N-08	N-08	N-08	Pilgrim	December 1974	100% Power	D
SWCC	SW -06	N-08	N-08	N-08	N-08	Pilgrim	May 1974	Power	D
SWCC	SW -07	N-31	N-31	N-31	N-31	TMI Unit 1	August 1978	100% Power	D
SWCC	SW -08	N-29	N-29	N-29	N-29	Oyster Creek	November 1978	Refueling	D
CHIL	CHIL-01	P-13	P-13	P-13	P-13	Calvert Cliffs	Jul, Sep 1980	90-100% Power	D
FAN	FAN -01	N-14	N-14	N-14	N-14	Crystal River 3	Nov/Dec 1978	98% Power	D
FAN	FAN -02	N-29	N-29	N-29	N-29	Three Mile Is 2	Jan/Dec 1982	Cold Shutdown	D
FAN	FAN -03	N-10	N-10	A	A	Dresden 2 & 3	November 1974	65% Power	D
FAN	FAN -04	N-16	N-16	N-16	N-16	Three Mile Is 2	February 1982	Shutdown	D
FAN	FAN -05	N-14	N-14	N-14	N-14	Susquehanna 1	Aug/Oct 1982	Preop & Startup	D
FAN	FAN -06	N-08	N-08	N-08	N-08	McGuire 1	July 1983	100% Power	D
FAN	FAN -07	P-19	P-19	P-19	P-19	Quad Cities 1	February 1978	83% Power	D
FAN	FAN -08	N-27	N-27	N-27	N-27	Three Mile Is 2	July 1980	Shutdown	D
FAN	FAN -09	N-10	N-10	N-10	N-10	Salem 1	September 1980	Cold Shutdown	D
FAN	FAN -10	N-10	N-10	N-10	N-10	Three Mile Is 2	August 1981	Shutdown	D
FAN	FAN -11	N-14	N-14	N-14	N-14	Arkansas 1	November 1977	100% Power	D
FAN	FAN -12	N-10	N-10	N-10	N-10	Susquehanna 1	Aug/Sep 1983	100% Power	D
FAN	FAN -13	N-14	N-14	N-14	N-14	Calvert Cliffs 1	Feb/Dec 1982	100% Power	D
FAN	FAN -14	N-27	N-27	N-27	N-27	Kewaunee	October 1975	99% Power	D
FAN	FAN -15	N-14	N-14	N-14	N-14	Browns Ferry 2	July/Aug 1983	95-97% Power	D
FAN	FAN -16	N-16	N-16	N-16	N-16	Dresden 3	August 1978	90% Power	D
FAN	FAN -17	N-12	N-12	N-12	N-12	Kewaunee	March 1984	83% Power	D

TABLE 1 (Continued): COMMON CAUSE EVENTS AND APPLICABILITY TO BYRON, BRAIDWOOD, QUAD CITIES AND LASALLE IPEs.

		APPL-RATIONALE							
TYPE	ID	BY	BR	QC	LS	PLANT	DATE	STATUS	P/B
MOV	MV -01	N-14	N-14	N-14	N-14	Arkansas One 1	August 1981	100% Power	D
MOV	MV -02	N-29	N-29	N-29	N-29	Turkey Point 3	April 1979	Refueling	D
MOV	MV -03	N-06	N-06	N-06	N-06	Arkansas One 1	April 1980	100% Power	D
MOV	MV -04	N-05	N-05	N-05	N-05	Zion 2	October 1975	83% Power	D
MOV	MV -05	A	A	A	A	Oconee 2	October 1975	Cold Shutdown	D
MOV	MV -06	N-30	N-30	N-30	N-30	Zion 2	December 1976	75% Power	D
MOV	MV -07	A	A	A	A	Turkey Point 3	April 1979	Refueling	D
MOV	MV -08	A	A	A	A	Arkansas 1	April 1980	100% Power	D
MOV	MV -09	N-06	N-06	N-06	N-06	Oconee 2	October 1975	Cold Shutdown	D
MOV	MV -10	N-05	N-05	N-05	N-05	Arkansas 1	August 1981	100% Power	D
MOV	MV -11	N-05	N-05	N-05	N-05	Zion 2	October 1975	83% Power	D
MOV	MV -12	N-10	N-10	N-10	N-10	Maine Yankee	February 1975	60% Power	D
MOV	MV -13	N-16	N-16	N-16	N-16	Vermont Yankee	February 1976	97% Power	D
MOV	MV -14	A	A	A	A	Browns Ferry 2	December 1974	Shutdown	D
MOV	MV -15	N-10	N-10	N-10	N-10	Pilgrim	September 1974	95% Power	D
MOV	MV -16	N-16	N-16	N-16	N-16	Davis Besse	December 1977	Power Esc. Test	D
MOV	MV -17	N-09	N-09	N-09	N-09	Kewaunee	September 1975	61% Power	D
MOV	MV -18	N-05	N-05	N-05	N-05	Trojan	October 1976	58% Power	D
MOV	MV -19	A	A	A	A	Palisades	January 1971	After Fuel Loading	D
MOV	MV -20	N-08	N-08	N-08	N-08	North Anna	August 1978	95% Power	D
MOV	MV -21	N-05	N-05	N-05	N-05	Rancho Seco	November 1976	Shutdown	D
MOV	MV -22	A	A	A	A	Cook 2	January 1979	2% Power	D
MOV	MV -23	A	A	A	A	Monticello	July 1972	Cold Shutdown	D
MOV	MV -24	N-07	N-07	N-07	N-07	Browns Ferry 2	December 1979	Cold Shutdown	D
MOV	MV -25	N-14	N-14	N-14	N-14	Robinson 2	January 1981	6% Power	D
MOV	MV -26	N-11	N-11	N-11	N-11	Surry 2	July 1981	100% Power	D
MOV	MV -27	N-08	N-08	N-08	N-08	Dresden 2	August 1973	Power	D
MOV	MV -28	N-08	N-08	N-08	N-08	Dresden 3	September 1975	Power	D
MOV	MV -29	N-14	N-14	N-14	N-14	Browns Ferry 1	September 1974	Cold Shutdow	D
MOV	MV -30	N-08	N-08	N-08	N-08	Hatch 2	September 1978	Shutdown	D
MOV	MV -31	N-14	N-14	N-14	N-14	Pilgrim	July 1977	100% Power	D
MOV	MV -32	P	P	P	P	Hatch 2	May 1980	Startup	D
MOV	MV -33	A	A	A	A	Hatch 2	May 1982	99% Power	D
MOV	MV -34	A	A	A	A	Dresden 2	May 1975	Refueling	D
MOV	MV -35	N-18	N-18	N-18	N-18	Vermont Yankee	September 1976	Shutdown	D
MOV	MV -36	A	A	A	A	Dresden 2	August 1973	Power	D
MOV	MV -37	A	A	A	A	Pilgrim	April 1973	Power	D
MOV	MV -38	N-30	N-30	N-30	N-30	Dresden 2	October 1973	Power	D
MOV	MV -39	A	A	A	A	Cooper	October 1980	98% Power	D

TABLE 1 (Continued): COMMON CAUSE EVENTS AND APPLICABILITY TO BYRON, BRAIDWOOD, QUAD CITIES AND LASALLE IPEs.

		APPL-RATIONALE							
TYPE	ID	BY	BR	QC	LS	PLANT	DATE	STATUS	P/B
SLRV	SLRV-01	N-14	N-14	N-14	N-14	Hatch 2	May 1984	Cold Shutdown	B
SRV	TRRV-01	N-10	N-10	N-10	N-10	Millstone 1	June 1983	-	B
SRV	TRRV-02	N-10	N-10	N-10	N-10	Brunswick 2	Nov 85-May 86	Refueling	B
SRV	TRRV-03	N-10	N-10	N-10	N-10	Brunswick 1	October 1982	4% Power	B
SRV	TRRV-04	N-10	N-10	N-10	N-10	Pilgrim	April 1984	Refueling	B
SRV	TRRV-05	N-10	N-10	N-10	N-10	Pilgrim	November 1981	Refueling	B
SRV	TRRV-06	N-10	N-10	N-10	N-10	Hatch 1	July 1982	100% Power	B
SRV	TRRV-07	N-10	N-10	N-10	N-10	Hatch 1	April 1981	-	B
SRV	TRRV-08	N-10	N-10	N-10	N-10	Hatch 1	June 1983	0% Power	B
SRV	TRRV-09	N-10	N-10	N-10	N-10	Hatch 2	November 1980	Refue..ng	B
SRV	TRRV-10	N-10	N-10	N-10	N-10	Fitzpatrick	March 1985	Refueling	B
SRV	TRRV-11	N-10	N-10	N-10	N-10	Brunswick 2	Nov 85-May 86	Refueling	B
SRV	TRRV-12	N-10	N-10	N-10	N-10	Pilgrim	April 1984	Refueling	B
SRV	EMRV-01	N-10	N-10	N-14	N-10	Nine Mile Point	May 1972	Shutdown	B
SRV	EMRV-02	N-10	N-10	N-14	N-10	Dresden 2	April-Nov 1970		B
SRV	EMRV-03	N-10	N-10	N-14	N-10	Quad Cities 2	Oct, Dec 1980	17% Power / Shutdown	B
SRV	EMRV-04	N-10	N-10	A	N-10	Oyster Creek	November 1984	12% Power	B
SRV	EMRV-04	N-10	N-10	A	N-10	Oyster Creek	November 1984	12% Power	B
SRV	EMRV-05	N-10	N-10	N-14	N-10	Dresden 2	June 1975	Startup	B
SRV	EMRV-06	N-10	N-10	A	N-10	Quad Cities 1	November 1976	77% Power	B
SRV	EMRV-07	N-10	N-10	A	N-10	Arnold	March 1977	Shutdown	B
SRV	EMRV-08	N-10	N-10	A	N-10	Quad Cities 1,2	March 1979	2% Power	B
SRV	EMRV-09	N-10	N-10	N-14	N-10	Oyster Creek	January 1980	Shutdown	B
SRV	EMRV-10	N-10	N-10	N-26	N-10	Dresden 1	May 1970	-	B
SRV	EMRV-11	N-10	N-10	N-14	N-10	Oyster Creek	December 1972	1830 MWt	B
CV	CV -01	N-08	N-08	N-08	N-08	Zion 2	November 1985	Refueling	D
CV	CV -02	N-10	N-10	A-34	N-10	Brunswick 2	March 1975	5% Power	D
CV	CV -03	N-07	N-07	N-07	N-07	Cook 2	November 1978	Shutdown	D
CV	CV -04	A-19	A-19	A-19	A-19	Crystal River	April 1980	Cold Shutdown	D
CV	CV -05	N-10	N-10	N-10	N-10	Trojan	March 1983	Shutdown	D
CV	CV -06	N-10	N-10	A-34	N-10	Trojan	March 1984	100% & 78% Power	D
CV	CV -07	N-10	N-10	N-10	N-10	Turkey Point 3,4	Nov 85/Jan 86	Power	D
CV	CV -08	N-26	N-26	N-26	N-26	Point Beach 1	July 1981	Cold Shutdown	D

TABLE 1 (Continued): COMMON CAUSE EVENTS AND APPLICABILITY TO BYRON, BRAIDWOOD, QUAD CITIES AND LASALLE IPEs.

TYPE	ID	APPL-RATIONALE BY	BR	QC	LS	PLANT	DATE	STATUS	P/B
BR	BRLA-01	N-14	N-14	N-14	N-14	Indian Point 3	November 1984	Cold Shutdown	D
BR	BRLA-02	N-27	N-27	N-27	N-27	Davis-Besse	August 1983	Shutdown	D
BR	BRLA-03	N-14	N-14	N-14	N-14	Zion 2	February 1979	55% power	D
BR	BRLA-04	N-10	N-10	N-10	N-10	Turkey Point 4	May 1975	Refueling Shutdown	D
BR	BRLA-05	N-27	N-27	N-27	N-27	Rancho Seco	July 1985	Cold Shutdown	D
BR	BRLA-06	A	A	A	A	Cooper	August 1984	90 % Power	D
BR	BRLA-07	N-08	N-08	N-08	N-08	Oyster Creek	September 1973	Shutdown	D
BR	BRLA-08	A	A	A	A	Cooper	January 1978	79% Power	D
BR	BRLA-09	N-08	N-08	N-08	N-08	Hatch 1	June 1978	Shutdown	D
BR	BRLA-10	N-10	N-10	N-10	N-10	Brunswick 2	October 1982	17% Power	D
BR	BRLA-11	N-08	N-08	N-08	N-08	Dresden 2	May 1971	Unknown	D
BR	BRLA-12	N-28	N-28	N-28	N-28	Washington Nuc 2	June 1985	Hot Shutdown	D
BR	BRLA-13	N-10	N-10	N-10	N-10	Dresden 1,2,3	August 1985	70% Power	D
BR	BRLA-14	N-10	N-10	N-10	N-10	Hatch 1,2	April 1981	Refueling	D
RTB	RTB -01	N-25	N-25	N-25	N-25	Conn. Yankee	December 1981	Power	D
RTB	RTB -02	N-25	N-25	N-25	N-25	Oconee 1	February 1979	98%Power	D
RTB	RTB -03	N-25	N-25	N-25	N-25	St. Lucie	November 1980	100% Power	D
RTB	RTB -04	A	A	A	A	Salem 1	February 1983	Startup	D
RTB	RTB -05	N-02	N-02	N-02	N-02	San Onofre 2	March 1983	Shutdown	D
RTB	RTB -06	N-15	N-15	N-15	N-15	McGuire 1	March 1983	Shutdown	D

NOTES - The following describes the headings and entries in Table 1:

TYPE - Type of component or common cause group. Acronyms used here defined below:

RTB - Reactor Trip Breaker
DG - Diesel Generator
MOV - Motor Operated Valve
SRV - Safety Relief Valve; does not include Electromatic Relief Valves.
EMRV- Electromatic Relief Valve
HHP - High Head Pump
RHSI- RH Pump and Low Head SI Pump
CS - Containment Spray Pump
AFW - Auxiliary Feedwater Pump
SWCC- Service Water and Component Cooling Water
CC - Service Water Pump
SW - Component Cooling Water Pump
HPRC- High Pressure Core Injection (HPIC) and Reactor Core Isolation Cooling (RCIC) Pumps
CHIL- HVAC Chiller
FAN - Containment Cooling and HVAC Fans
SLRV- Standby Liquid Control Relief Valve
CV - Check Valve
BRLA- Circuit Breaker, Large AC

ID - Event Identification number assigned to "A Database of Common Cause Events for Risk and Reliability Evaluation", PLG-0866, PLG Inc., March 1992.

PLANT - Plant Name and Unit if available
BY - Byron Station
BR - Braidwood Station
QC - Quad Cities Station
LS - LaSalle Station

DATE - Date of event
STATUS - Plant status at time of event
P/B - Component applicability to PWRs (P), BWRs (B), or both (D).

APPL-RATIONALE - These columns contain the applicability of each event followed by the rational for its applicability or non-applicability to the CECo database. There are three columns which describe applicability. The BY (Byron Station), BR (Braidwood Station), QC (Quad Cities Station), or LS (LaSalle Station) columns contain the site specific applicability-rationale.

The first application-rationale designator indicates assigned applicability of common cause events to specific stations as follows:

A - Applicable for common cause considerations at CECo Plants.
N - Not applicable for common cause considerations at CECo Plants.
P - Low probability of applicability. Used in MGL calculation in absence of other data.

The second designator (separated from the first by a hyphen is the rationale for assigning the applicability or non-applicability. These are assigned in an alpha numeric fashion. Each designator is unique and where two are given, the first listed is the most important with the second giving additional information. The designators are described below:

01 - Events modeled explicitly in systems analysis.
02 - Events occurring prior to commercial operation detected as a result of start-up testing.
03 - Events occurring during shutdown conditions that cannot occur during power operation.
04 - Events involving failures or potential failures that do not have a significant impact in analyses for PRA applications.
05 - Root cause of common cause events is torque switches on MOVs. This common cause failure mechanism has been removed a CECo plants by MOV directive, Guidelines for Motor-Operated Valve (MOV) Testing, Maintenance and Evaluation, Revision 2, NO Directive NOD-MA.1, Commonwealth Edison, September 1990.
06 - Root cause of common cause events is loose bolts on MOV. This common cause failure mechanism has been removed a CECo plants by MOV directive, see note 5.
07 - Failure would have been prevented by a Post Operational Test or a Post Failure Test.
08 - Failure would not have occurred in a mature CECo plant.
09 - Failure would have been prevented by the CECo EQ program for grease.
10 - Failure would not occur at the specific CECo plant. Equipment configuration or condition does not exist at that specific plant.
11 - Failure would be prevented at CECo plant by independent verification post maintenance or control boarding.
12 - Human error problem. CECo plants have procedures in place to prevent errors of this type.
13 - Human error problem. CECo plants have procedures in place to prevent errors of this type and the event is easily recoverable.
14 - Single failure(s). Little to no evidence that a common cause failure exists.
15 - Single failure(s). Little to no evidence that a common cause failure exists. There was a significant time period between failures.
16 - Modeled explicitly in IPE.
17 - This common cause failure would be prevented at CECo plant by QA inspection of new components.
18 - Event does not have any failures. Potential common cause event based upon potential failures.
19 - Common cause event is applicable but impact to CECo plants is lessened.
20 - Common cause event is applicable but impact to CECo plants is lessened by MOV directive, see note 05.
21 - Common cause event is applicable but impact to CECo plants is lessened by EQ program.
22 - Common cause event is applicable but impact to CECo plants is lessened by MOV directive, see note 05, and its impact on MOV loose bolts.
23 - Common cause event is applicable but impact to CECo plants is lessened. Event is based on degraded performance not failure.
24 - DG trip caused by permissives which are not included in those in use when diesel is operated in bypass (emergency condition).
25 - Modified RTB system with shunt trip makes this common cause failure unrealistic.
26 - This problem is well known and common cause failure mechanism has been removed.
27 - There are procedures in place at CECo plants to prevent this common cause event from occurring.
28 - This is a non-repeatable event. Problem solved, procedures and\or equipment in place to prevent common cause failures of this type at CECo plants.
29 - Failure mode not applicable to success criteria.
30 - Failure mode not applicable to success criteria. Not a failure, partial degradation.
31 - Failure mode not applicable to success criteria. Event is easily recoverable.
32 - Failure mode not applicable to success criteria RTBs were slow, partial degradation.
33 - There is reverse flow protection to prevent this event from occurring.
34 - Applicable only to Testable Check Valves

Attachment 4-C

TABLE 4.5.1-2
LOOP SUPPORT MODEL QUANTIFICATION RESULTS

NUMBER (1)	FREQUENCY (2)	PERCENT (3)	EVENT (4)	VALUE (5)	DESCRIPTION (6)
1.	2.54E-02	79.21%	LOOP 1TB	3.20E-02 1.00E+00	SINGLE UNIT LOOP EVENTS EVENT FAILS
2.	2.12E-03	6.63%	LOOP DG1 1TB	3.20E-02 7.81E-02 1.00E+00	SINGLE UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) EVENT FAILS
3.	1.91E-03	5.97%	LOOP DGB 1TB	3.20E-02 7.10E-02 1.00E+00	SINGLE UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) EVENT FAILS
4.	1.24E-03	3.89%	LOOP SW 1IA	3.20E-02 4.59E-02 1.00E+00	SINGLE UNIT LOOP EVENTS FAILURE OF SW (LOOP) EVENT FAILS
5.	5.07E-04	1.58%	LOOP 1TB 1IA	3.20E-02 1.00E+00 1.96E-02	SINGLE UNIT LOOP EVENTS EVENT FAILS IA FAILS (LOOP, DLOOP)
14.	2.19E-05	0.07%	LOOP DGB 18 1TB	3.20E-02 7.10E-02 1.13E-02 1.00E+00	SINGLE UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) LOSS OF BUS 18, 13-1 UNAVAIL EVENT FAILS
17.	1.02E-05	0.03%	LOOP DGB 14 1IA	3.20E-02 7.10E-02 5.50E-03 1.00E+00	SINGLE UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) LOSS OF BUS 14 (345KV UNAVAIL) EVENT FAILS
21.	5.57E-06	0.02%	LOOP 13 14 1IA	3.20E-02 5.57E-03 4.05E-02 1.00E+00	SINGLE UNIT LOOP EVENTS LOSS OF BUS 13 (345KV UNAVAIL) LOSS OF BUS 14 AFTER 13, 14-1 AVAIL EVENT FAILS
26.	2.02E-06	0.01%	LOOP DGB DG1 141 SBO?	3.20E-02 7.10E-02 8.44E-02 1.17E-02 1.00E+00	SINGLE UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) LOSS OF DG1 AFTER DG1/2 (6 HRS) LOSS OF BUS 14-1, 14 & DG1 UNAVAIL, X-TIE AVAIL SBO OCCURS IN UNIT 1

Notes:

1. "Number" refers to support state model sequence.
2. "Frequency" is the frequency per year that this initiator/support combination is expected to occur.
3. "Percent" is the percent of off-normal conditions for the subject initiators that would involve this state.
4. "Event" is the model top event label.
5. "Value" is frequency (for initiators) or probability (for failures) that the event would occur.
6. "Description" defines the event label.

Attachment 4-D

TABLE 4.5.1-3
DUAL UNIT LOOP SUPPORT MODEL QUANTIFICATION RESULTS

NUMBER (1)	FREQUENCY (2)	PERCENT (3)	EVENT (4)	VALUE (5)	DESCRIPTION (6)
1.	1.21E-02	74.98%	DLOOP 1TB	1.61E-02 1.00E+00	DUAL UNIT LOOP EVENTS EVENT FAILS
2.	9.85E-04	6.13%	DLOOP DG1 1TB	1.61E-02 7.81E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) EVENT FAILS
3.	9.16E-04	5.69%	DLOOP DGB 1TB	1.61E-02 7.10E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) EVENT FAILS
4.	8.49E-04	5.28%	DLOOP DG2 1TB	1.61E-02 6.60E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG2 TO BUS 24-1 (6 HRS) EVENT FAILS
5.	3.61E-04	2.24%	DLOOP SW	1.61E-02 2.85E-02	DUAL UNIT LOOP EVENTS FAILURE OF SW (DLOOP), 23 UNAVAIL
6.	2.41E-04	1.50%	DLOOP 1TB 1IA	1.61E-02 1.00E+00 1.96E-02	DUAL UNIT LOOP EVENTS EVENT FAILS IA FAILS (LOOP, DLOOP)
7.	8.14E-05	0.51%	DLOOP DG1 DGB 1TB	1.61E-02 7.81E-02 7.68E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) LOSS OF DG1/2 AFTER DG1, (6 HRS) EVENT FAILS
8.	7.69E-05	0.48%	DLOOP DG1 DG2 SBO?	1.61E-02 7.81E-02 7.15E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) LOSS OF DG2 AFTER DG1 (6 HRS) SBO IN UNIT 2, NO SBO IN UNIT 1
20.	1.11E-05	0.07%	DLOOP DG1 DG2 DGB SBO?	1.61E-02 7.81E-02 7.15E-02 1.24E-01 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) LOSS OF DG2 AFTER DG1 (6 HRS) LOSS OF DG1/2 AFTER DG1 AND DG2, (6 HRS) SBO IN UNIT 1, SBO IN UNIT 2
21.	1.05E-05	0.07%	DLOOP DGB 18 1TB	1.61E-02 7.10E-02 1.13E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) LOSS OF BUS 18, 13-1 UNAVAIL EVENT FAILS
27.	4.73E-06	0.03%	DLOOP DGB 14	1.61E-02 7.10E-02 5.50E-03	DUAL UNIT LOOP EVENTS LOP FROM DG1/2 (6 HRS) LOSS OF BUS 14 (345KV UNAVAIL)
30.	2.57E-06	0.02%	DLOOP 13 14	1.61E-02 5.57E-03 4.05E-02	DUAL UNIT LOOP EVENTS LOSS OF BUS 13 (345KV UNAVAIL) LOSS OF BUS 14 AFTER 13, 14-1 AVAIL
44.	9.16E-07	0.01%	DLOOP DG1 DGB 141 SBO?	1.61E-02 7.81E-02 7.68E-02 1.17E-02 1.00E+00	DUAL UNIT LOOP EVENTS LOP FROM DG1 TO BUS 14-1 (6 HRS) LOSS OF DG1/2 AFTER DG1, (6 HRS) LOSS OF BUS 14-1, 14 & DG1 UNAVAIL, X-TIE AVAIL SBO IN UNIT 1, NO SBO IN UNIT 2

TABLE 4.5.1-3 (Continued)
DUAL UNIT LOOP SUPPORT MODEL QUANTIFICATION RESULTS

Notes:

1. "Number" refers to support state model sequence.
2. "Frequency" is the frequency per year that this initiator/support combination is expected to occur.
3. "Percent" is the percent of off-normal conditions for the subject initiators that would involve this state.
4. "Event" is the model top event label.
5. "Value" is frequency (for initiators) or probability (for failures) that the event would occur.
6. "Description" defines the event label.