Final Precursor Analysis

Accident Sequence Precursor Program --- Office of Nuclear Regulatory Research

Quad Cities 2	Loss of offsite power to Unit 2 but not Unit 1 due to failure of Unit 2 main power transformer with the subsequent failure of a switchyard breaker relay	
Event Date: 08/02/2001	**LER:** 265/01-001	**CCDP =** 5×10^{-6}

Event Summary

On August 2, 2001, at 0813 hours, lightning struck a 345-kv line that connected to the Quad Cities switchyard. Both Unit 1 and Unit 2 were at 100% power. The lightning strike caused the Unit 2 main power transformer to rupture and catch fire, leading to an automatic shutdown of the Unit 2 reactor. Subsequently, additional breakers in the switchyard supplying offsite power to the Unit 2 reserve auxiliary transformer (RAT) opened. Consequently, Unit 2 lost all offsite power. Unit 1 remained connected to the offsite grid with a reduced number of offsite power lines. (Ref. 1)

An unusual event was declared following the Unit 2-centered loss of offsite power (LOOP). The swing emergency diesel generator (EDG 1/2) and the Unit 2 emergency diesel generator (EDG 2) automatically started as required and supplied electrical power to the safety-related buses (bus 23-1 and bus 24-1) for Unit 2. The two station blackout EDGs were manually started as required by station procedures but were not manually loaded to any electrical bus since this was not required. The Unit 1 EDG (EDG 1) was not required to start because bus 14-1 did not lose voltage, as its electrical feed was from Unit 1. An alternate source of offsite power from Unit 1 to Unit 2, using the RAT of Unit 1 feeding through the station emergency bus cross-tie to Unit 2, was available, but this source of offsite power for Unit 2 was not used during the event.

The Unit 2 reactor core isolation cooling (RCIC) system and the safe shutdown makeup pump were manually started and used to maintain reactor vessel water level. Reactor pressure was controlled with the main steam relief valves. All safety systems operated as designed to shut down the Unit 2 reactor and maintain it in a safe shutdown condition. There were no failures of equipment following the Unit 2-centered LOOP that complicated the controlled shutdown of Unit 2.

The fire in the Unit 2 main power transformer was extinguished at approximately 0845 hours (approximately 32 minutes after the lightning strike) by (1) the automatic actuation of the transformer's fire protection deluge system, (2) actions of the station fire brigade, and (3) actions of the local fire departments. Offsite electrical power to Unit 2 emergency buses (buses 23-1 and 24-1) from the Unit 2 RAT was restored at approximately 1047 hours. EDG 1/2 and EDG 2 were then shut down. The Unit 2-centered LOOP lasted approximately 2.5 hours.

Unit 1 power was lowered to approximately 93% following the LOOP at Unit 2. Due to the Unit 2-centered LOOP, Unit 1 was in a 7-day technical specification limiting condition of operation (LCO) from 0813 hours to 1047 hours due to offsite electrical power not being available from Unit 2. Unit 1 was also in another 7-day LCO because the swing diesel, EDG 1/2, was dedicated for use at Unit 2 and not available for Unit 1 from 0855 hours to 1041 hours.

Cause. The cause of the Unit 2 main power transformer failure was original equipment manufacturer design and construction errors that allowed the mechanical failure of the bus bar clamps (due to undersized bus bars and bus bar clamp bolts). After the lightning strike, this mechanical failure of the bus bar clamps created a phase-to-phase fault in the main power transformer, which caused a fire in the transformer. The Unit 2 main power transformer was subjected to multiple electrical faults during its service life, which contributed to its ultimate failure. Although the licensee knew about the faults, they were not tracking the number of faults or the severity of the faults on the transformer. The cause of the subsequent loss of all offsite power to Unit 2 was a transistor failure due to age degradation in a static breaker failure relay, causing a slow relay reset time (Ref. 1). The age-related degradation was not recognized earlier due to the failure to include completion of the reset function in their relay testing program.

Initiating event. For Unit 2, the event is considered a unit-centered LOOP caused by failure of a switchyard breaker relay to properly respond to failure of the Unit 2 main power transformer.
For Unit 1, there is no initiating event. For approximately 2.5 hours, Unit 1 had restricted electrical power while offsite power was being restored to Unit 2. The 2.5-hour time period that Unit 1 had restricted electric power is much shorter than the time allowed by the Unit 1 technical specifications. In addition, a screening evaluation was performed that indicated the risk significance of restricted electrical power at Unit 1 for this event was negligible.

Recovery opportunities. At the time of the Unit 2 scram, offsite power was available from Unit 1 for use at Unit 2. However, the operators chose not to use this Unit 1 source of electric power but rather to use the two emergency diesel generators that automatically started and ran for approximately 2.5 hours. The actual recovery of offsite power to Unit 2 was accomplished by using Unit 2 offsite power sources at approximately 2.5 hours.

Normal recovery of equipment (default value) was used in the risk analysis for equipment not impacted by the Unit 2 main power transformer fire.

Analysis Results

- **CCDP**[1]

Conditional core damage probability (CCDP) is 5.4×10^{-6} (mean).

	Point Value	Mean	5%	95%
CCDP	5.5×10^{-6}	5.4×10^{-6}	7.2×10^{-7}	1.7×10^{-5}

This CCDP exceeds the Accident Sequence Precursor (ASP) program acceptance threshold value for an initiating event. The CCDP is greater than $1.0 \text{ X } 10^{-6}$, and the CCDP is greater than the CCDP for a transient with loss of reactor feedwater and no reactor feedwater recovery, which is $1.2 \text{ X } 10^{-6}$ (point estimate).

[1] For the initiating event assessment, the parameter of interest is the absolute value of the CCDP.

It should be noted that this initiating event assessment is equivalent to calculating the conditional core damage probability of Unit 2 for a unit-centered LOOP because there were no other failures in the actual event following the Unit 2-centered LOOP.

- **Dominant sequence**

  LOOP Initiating Event: The core damage sequence with the highest CCDP (2.4×10^{-6} or 43.6% of the total) for the Unit 2 initiating event assessment is LOOP Sequence 65 (see Figure 1). Three other significant core damage sequences are LOOP Sequence 62-04-5 (9.3×10^{-7} or 16.9%), LOOP Sequence 09-5 (9.0×10^{-7} or 16.4%), and LOOP Sequence 61 (7.1×10^{-7} or 12.9%). The events and important TOP events for these three sequences are shown in Table 1 and Table 2a. These include:

  LOOP Sequence 65

  – reactor protection system (RPS) fails

  LOOP Sequence 62-04-5

  – RPS works
  – emergency electrical power system works
  – one safety relief valve (SRV) sticks open
  – safe shutdown makeup system works
  – suppression pool cooling fails
  – containment spray system fails
  – containment venting fails
  – following containment failure, equipment fails because of survivability concerns

  LOOP Sequence 09-5

  – RPS works
  – emergency electrical power system works
  – all SRVs close
  – RCIC system works
  – suppression pool cooling fails
  – manual depressurization works
  – shutdown cooling fails
  – containment spray system fails
  – containment venting fails
  – following containment failure, equipment fails because of survivability concerns

  LOOP Sequence 61

  – reactor protection system works
  – emergency electrical power system works
  – all SRVs close
  – RCIC system fails
  – high pressure coolant injection (HPCI) system fails
  – safe shutdown makeup system is unavailable

- manual depressurization fails
- insufficient control rod drive (CRD) flow to the reactor coolant system

- **Results tables**

  - The conditional probabilities of the dominant sequences for the Unit 2-centered LOOP are shown in Table 1.
  - The event tree sequence logic for the dominant sequences is provided in Table 2a. Definitions of TOP events are provided in Table 2b.
  - The highest value conditional cut sets are provided in Table 3.
  - The definitions and probabilities for certain basic events are provided in Table 4.

Modeling Assumptions

- **Assessment summary**

  This event was modeled as a unit-centered LOOP initiating event for Unit 2.

- **SPAR model used in the analysis**

  The Standardized Plant Analysis Risk (SPAR) model for Quad Cities 1 & 2 (Rev. 3) was used for this assessment (Ref. 2). The naming convention for event trees, fault trees, and basic events in the model is for Unit 1; however, the model is valid for either unit.

- **Unique system and operational considerations**

  None.

- **Modifications to event tree models**

  Recovery of long term shutdown cooling. The recovery rules for the LOOP event tree were modified to credit recovery of shutdown cooling late in certain sequences. This was done in a manner similar to the use of a nonrecovery term for the transient (TRANS) event tree. In the TRANS event tree, the nonrecovery term SDC-LTERM-NOREC was added to certain sequences where (1) the reactor protection system successfully tripped the reactor, (2) the power conversion system has failed, (3) no relief valves have stuck open, (4) high pressure injection (RCIC, HPCI, or safe shutdown system) was successful, (5) the reactor has been successfully depressurized, but (6) long-term decay heat removal has failed (suppression pool cooling [SPC], shutdown cooling [SDC], and containment spray system [CSS]). The selected sequences in the LOOP event tree are sequences 8, 9, 22, 23, and 33. The nonrecovery event SDC-LTERM-NOREC2 (Operator fails to recover shutdown cooling long in the long term) was added to selected sequences of the LOOP event tree where (1) the reactor protection system has successful tripped the reactor, (2) the emergency power system has successfully restored power, (3) no relief valves have stuck open, (4) high pressure injection (RCIC, HPCI, or safe shutdown system) was successful, (5) the reactor has been successfully depressurized, but (6) long-term decay heat removal has failed (SDC and CSS). The recovery rules for the LOOP event tree were modified as follows:

Long-term recovery of SDC given initial success of injection.

```
if system(/RPS) * system(/EPS) * system(/SRV) * (system(/RCI2) + system(/HCI) +
system(/SSM)) * system(SDC) * system(CSS) then
AddEvent = SDC-LTERM-NOREC2;
endif
```

The value used for SDC-LTERM-NOREC2 in the LOOP sequences was based on the similarity between a unit-centered LOOP with success of the electrical power system and a transient with loss of the power conversion system. In a unit-centered LOOP with success of the electrical power system and no stuck-open relief valve, the recovery of the decay heat removal systems in the long term should be identical to the recovery of the decay heat removal systems in the long term for TRANS with loss of the power conversion system and with no stuck-open relief valve. There is nothing in the unit-centered LOOP logic that would indicate that the operators would have less time to recover the residual heat removal system (RHR) in the long term, that recovery would be any more complicated, or that the stress level would be any higher. The initial stages of the two events might be different, but the long-term RHR recovery actions or inactions would be the same. However, in order to add some conservatism to the analysis, the value used for SDC-LTERM-NOREC2 (3.2E-2) was taken to be twice the value used for SDC-LTERM-NOREC (1.6E-2).

Treatment of RPS. The dominant sequence for core damage is the failure of RPS. In the event tree for LOOP (see Figure 1), the failure of RPS following LOOP (Sequence 65) leads directly to core damage and not to a transfer to an ATWS event tree as found in the IE-TRANS event tree. No modification to Sequence 65 was made for the analysis. No documentation could be found that would allow a change to the sequence to allow a transfer to an ATWS event tree following LOOP. Also, even though the probability of failure of RPS following IE- LOOP is less than the probability of failure of RPS following IE-TRANS, the same values were used for RPS failure following IE-LOOP as used for RPS failure following IE-TRANS. This treatment of RPS results in a higher CCDP in the analysis than might be calculated with more complete documentation of the response of RPS following IE-LOOP.

- **Modifications to fault tree models**

Changes were made to the fault tree for the LOOP FLAG sets to allow setting loss of power to the various divisions of electric power. These changes are shown in the table below and in Figures 2 through 15. In addition, a basic event was added to the division I and II ac electric power trees to model the ability of the operators to cross-connect the 4160 V buses to Unit 1, which had offsite power (see Figures 5 and 8).

Fault Tree	Unmodified FLAG	Modified FLAG	Figure
CRD-A	LOOP	LOOP-I	Figure 2
CRD-B	LOOP	LOOP-II	Figure 3
CVS	LOOP	LOOP-I or LOOP-II	Figure 4
DIV-1-AC	LOOP-I	LOOP-I	Figure 5
DIV-1-AC-U2	LOOP-I-U2 –	LOOP-I-U2 LOOP-I	Figure 6
DIV-1-DC	LOOP	LOOP-I	Figure 7
DIV-2-AC	LOOP-II	LOOP-II	Figure 8
DIV-2-AC-U2	LOOP-II-U2	LOOP-II-U2	Figure 9
DIV-2-DC	LOOP	LOOP-II	Figure 10
SWS-U1A	LOOP	LOOP-I	Figure 11
SWS-U1B	LOOP	LOOP-II	Figure 12
SWS-U2A	LOOP	LOOP-I-U2	Figure 13
SWS-U2B	LOOP	LOOP-II-U2	Figure 14
TBC-A	LOOP	LOOP-I	Figure 15

- **Initiating event probability changes**

  For this analysis, the frequency for initiating event IE-LOOP was set equal to 1.0 and the frequencies for all the other initiating events were set to zero. The LOOP FLAG sets were changed as follows to make this a unit-centered LOOP.

  – LOOP = TRUE
  – LOOP-I = TRUE
  – LOOP-I-U2 = FALSE
  – LOOP-II = TRUE
  – LOOP-II-U2 = FALSE

- **Basic event probability changes**

  Table 4 provides the basic events that were changed to analyze this event.

  Several of the basic events changed involve the recovery of ac electrical power. The values used were based on the assumption that offsite power was available from Unit 1 at time T = 0. A general description of the approach to estimating electric power recovery is contained in Attachment A. One of the important assumptions regarding the recovery of offsite power from the Unit 2 switchyard is that at least 30 minutes is required to restore power to

emergency loads with offsite power available at time T = 0.0. As seen in Attachment A and Table 5, the final value used in the analysis is dependent on the performance shaping factor used for the time available.

- ***Probability that the operator fails to recover ac power in 30 minutes (ACP-XHE-NOREC-30).*** This probability was changed to 1.0E-1 as shown in Table 5. The performance shaping factor for time was given a value of 10 since the time available to perform the action is approximately equal to the time required to perform the action.

- ***Probability that the operator fails to recover ac power in 90 minutes (ACP-XHE-NOREC-90).*** This probability was changed to 1.0E-2 as shown in Table 5. The performance shaping factor for time was given a value of 1.0 since the time available to perform the action is between two and four times the time required to perform the action.

- ***Probability that the operator fails to recover ac power in 4 hours (ACP-XHE-NOREC-4H).*** This probability was changed to 1.0E-3 as shown in Table 5. The performance shaping factor for time was given a value of 0.1 since the time available to perform the action is greater than five times the time required to perform the action.

- ***Probability that the operator fails to recover ac power before battery depletion - 4 hours (ACP-XHE-NOREC-BD).*** This probability was changed to 1.0E-3 as shown in Table 5. The performance shaping factor for time was given a value of 0.1 since the time available to perform the action is greater than five times the time required to perform the action.

- ***Probability that the emergency diesel generator fails to run for the medium term (EPS-DGN-FR-FTRM).*** This probability was changed to 9.0E-4 based on a total mission time of 1 hour. That is: the value represents 0.5 hours at the failure to run/hour of short term and 0.5 hours at the failure to run/hour of medium term.

- ***Probability that the operator fails to recover offsite power in 1 hour (OEP-XHE-NOREC-1H).*** This probability was changed to 4.0E-3 as shown in Table 5. The performance shaping factor for time was given a value of 1.0 since the time available to perform the action is between two and four times the time required to perform the action.

- ***Probability that the operator fails to recover offsite power in 2 hours (OEP-XHE-NOREC-2H).*** This probability was changed to 4.0E-3 as shown in Table 5. The performance shaping factor for time was given a value of 1.0 since the time available to perform the action is between two and four times the time required to perform the action.

- ***Probability that the operator fails to recover offsite power in 4 hours (OEP-XHE-NOREC-4H).*** This probability was changed to 4.0E-4 as shown in Table 5. The performance shaping factor for time was given a value of 0.1 since the time available to perform the action is greater than five times the time required to perform the action.

- ***Probability that the operator fails to recover offsite power in 10 hours (OEP-XHE-NOREC-10H).*** This probability was changed to 4.0E-4 as shown in Table 5. The performance shaping factor for time was given a value of 0.1 since the time available to perform the action is greater than five times the time required to perform the action.

– ***Unit 2 cross-tie fails from bus 23-1 (EPS-XHE-BUS-23-1).*** This event was added to model the ability of operators to cross connect bus 13-1 to Unit 2 bus 23-1 (see Figure 5). This event is assumed to be similar to event EPS-XHE-XE-SBO1 (operator fails to align Unit 1 SBO diesel generator to dead bus), and the nominal human error probability of 1.0E-3 for an action task was used for this event. This basic event does not depend on the recovery of offsite power to the Unit 2 switchyard.

– ***Unit 2 cross-tie fails from bus 24-1 (EPS-XHE-BUS-24-1).*** This event was added to model the ability of operators to cross connect bus 14-1 to Unit 2 bus 24-1 (see Figure 8). This event is assumed to be similar to event EPS-XHE-XE-SBO2 (operator fails to align Unit 2 SBO diesel generator to dead bus), and the nominal human error probability of 1.0E-3 for an action task was used for this event. This basic event does not depend on the recovery of offsite power to the Unit 2 switchyard.

- **Model update**

Changes to the Rev. 3 SPAR model for Quad Cities are as follows:

– Fault tree logic for the injection valve in the HPCI system was updated. A modification was made to the HCI and HC1 fault trees to address the basic event HCI-MOV-CC-IVFRO, failure of injection valve to reopen. The basis for the modifications is given in the footnotes to Table 2b. (Updated fault trees are presented in Figures 16 and 17.)

– Fault tree logic for the division I and II electric power systems for both units was updated. The logic for the station blackout (SBO) buses was revised to remove the ability to supply the bus with power from the other unit's SBO diesel generator. SBO buses 61 and 71 cannot be tied together if either bus is feeding a 4160 V safety bus. (Updated fault trees are presented in Figures 5, 6, 8, and 9.)

– Alpha factors used to calculate the common-cause failure probability for failure to run for the motor-driven service water pumps were updated based on guidance provided by Idaho National Engineering Laboratory. (See Table 6 for the updated alpha factors.)

– Alpha factors used to calculate the common-cause failure probability for failure to run for the RHR motor-driven pumps were updated based on guidance provided by Idaho National Engineering Laboratory. (See Table 6 for the updated alpha factors.)

– Alpha factors used to calculate the common-cause failure probability for the batteries were updated based on guidance provided by Idaho National Engineering Laboratory. (See Table 6 for the updated alpha factors.)

– The failure rate for batteries and battery chargers was updated based on guidance provided by Idaho National Engineering Laboratory. (See Table 4 for the updated failure probabilities.)

These updates are independent of the actual events being analyzed. Bases for the updates are described in the footnotes to Table 2b or 4.

- **Related events**

  None

- **Sensitivity studies**

  For selected sequences, credit was given for recovery of shutdown cooling in the long term. For the initiating event assessment, the nonrecovery value used for SDC-LTERM-NOREC2 was 3.2E-2. This value is two times the value used for nonrecovery of shutdown cooling in the long term for transient sequences. A sensitivity study was made using a value of 0.16 for SDC-LTERM-NOREC2. With this change, the CCDP value increases by a factor of 2 to 9.4E-6 (point estimate). Sensitivity results are provided in the following table.

Event tree name	Sequence no.	Conditional core damage probability (CCDP)[1]	Percentage contribution
LOOP	09-5	4.5×10^{-6}	47.9
LOOP	65	2.4×10^{-6}	25.5
LOOP	62-04-5	9.3×10^{-7}	9.9
LOOP	61	7.1×10^{-7}	7.6
Total (all sequences)[2]		$\mathbf{9.4 \times 10^{-6}}$	N/A

Note:
1. Values are point estimates. (File name: GEM 265-01-001 Sensitivity 1-7-2004 134536.wpd).
2. Total CCDP includes all sequences (including those not shown in this table).

- **Analysts**

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References

1. LER 265/01-001, Revision 1, *Quad Cities Nuclear Power Station, Unit 2, Reactor Scram due to Failure of Main Power Transformer*, April 10, 2002 (ADAMS Accession Number: ML021190402).

2. J. A. Schroeder, *Standardized Plant Analysis Risk Model for Quad Cities 1 & 2 (ASP BWR C),* Revision 3, Idaho National Engineering and Environmental Laboratory, February 2002, Internet computer update was March 7, 2002.

3. D. M. Ericson, Jr., et. al., *Analysis of Core Damage Frequency: Internal Events Methodology*, NUREG/CR-4550, Vol. 1, Rev. 1, Sandia National Laboratories, January 1990.

Table 1. Conditional probabilities associated with the highest probability sequences for the initiating event assessment.

Event tree name	Sequence no.	Conditional core damage probability (CCDP)[1]	Percentage contribution
LOOP	65	2.4E-006[2]	43.6
LOOP	62-04-5	9.3E-007	16.9
LOOP	09-5	9.0E-007	16.4
LOOP	61	7.1E-007	12.9
Total (all sequences)[3]		**5.5E-006**	N/A

Note:
1. Values are point estimates. (File name: GEM 265-01-001 1-7-2004 151731.wpd).
2. No credit was taken for the loss of offsite power deenergizing relays and solenoids.
3. Total CCDP includes all sequences (including those not shown in this table).

Table 2a. Event tree sequence logic for the initiating event dominant sequences.

Event tree name	Sequence no.	Logic (“/” denotes success; see Table 2b for TOP event names)
LOOP	65	RPS
LOOP	62-04-5	/RPS /EPS P1 /SSM SPC CSS CVS SURVIVE
LOOP	09-5	/RPS /EPS /SRV /RCI2 SPC /DEP SDC CSS CVS SURVIVE
LOOP	61	/RPS /EPS /SRV RCI2 HCI SSM DEP CRD

Table 2b. Definitions of TOP events listed in Table 2a.

TOP event	Definition
CRD[1]	Insufficient CRD flow to RCS
CSS	Containment spray mode of residual heat removal (RHR) system fails
CVS[1]	Containment venting fails
DEP	Manual depressurization fails
EPS	Emergency EPS fails
HCI[2]	HPCI fails to provide sufficient flow to reactor vessel
P1	One SRV fails to close
RCI2	RCIC fails to provide sufficient flow to reactor vessel during LOOP
RPS	Reactor shutdown fails
SDC	Shutdown cooling mode of residual heat removal system fails
SPC	Suppression pool cooling mode of residual heat removal system fails
SRV	One or more safety relief valves fail to close
SSM	Safe shutdown makeup system is unavailable
SURVIVE	Following containment failure, equipment survivability fails

Notes:
1. Changes were made to the fault tree for the LOOP FLAG sets to allow setting loss of power to the various divisions of electric power.
2. Fault tree logic for the injection valve in the HPCI system was updated. A modification was made to the HCI and HC1 fault trees to address the basic event HCI-MOV-CC-IVFRO, failure of injection valve to reopen. This single basic event in the two fault trees was replaced by an AND gate with three basic events feeding the AND gate. (See gate HC1-10 in Figure 16 and gate HCI-10 in Figure 17.) This modification was made to consider the possibility of multiple injections of water into the reactor coolant system by the HPCI system.

Table 3. Conditional cut sets for LOOP sequences.

CCDP[1]	Percent contribution	Minimal cut sets[2]
Event Tree: LOOP Sequence 65		
1.7×10^{-6}	69.7	RPS-SYS-FC-PSOVS[3]
3.8×10^{-7}	15.6	RPS-SYS-FC-RELAY[3]
2.5×10^{-7}	10.2	RPS-SYS-FC-CRD
2.4×10^{-6}	**Total[4]**	
Event Tree: LOOP Sequence 62-04-5		
7.9E-007	84.9	PPR-SRV-OO-1VLV CVS-XHE-XE-VENT2 RHR-XHE-XM-ERROR
9.4×10^{-7}	**Total[4]**	
Event Tree: LOOP Sequence 09-5		
7.9E-007	87.3	/SRV CVS-XHE-XE-VENT2 RHR-XHE-XE-ERROR SDC-LTERM-NOREC2
9.0×10^{-7}	**Total[4]**	
Event Tree: LOOP Sequence 61		
1.8E-007	25.2	/SRV DCP-BAT-CF-ALL
8.7E-008	12.2	/SRV DCP-XHE-XE-BCH2A DCP-BDC-LP-BUS1A
7.1×10^{-7}	**Total[4]**	
Total all sequences (including those not shown) = 5.5×10^{-6}		

Notes:
1. Values are point estimates.
2. See Table 4 for definitions and probabilities for the basic events.
3. No credit was taken for the loss of offsite power deenergizing relays and solenoids.
4. Total CCDP includes all cut sets (including those not shown in this table).

Table 4. Definitions and probabilities for modified or dominant basic events.

Event name	Description	Probability/ Frequency	Modified
ACP-XHE-NOREC-30	Operator fails to recover ac electrical power before 30 minutes	1.0E-1	Yes[1]
ACP-XHE-NOREC-90	Operator fails to recover ac electrical power before 90 minutes	1.0E-2	Yes[1]
ACP-XHE-NOREC-4H	Operator fails to recover ac electrical power before 4 hours	1.0E-3	Yes[1]
ACP-XHE-NOREC-BD	Operator fails to recover ac electrical power before battery depletion - 4 hours	1.0E-3	Yes[1]
CVS-XHE-XE-VENT2	Dependent operator action - fails to vent containment given operator fails to start/control RHR	5.1E-2	No
DCP-BAT-CF-ALL	Batteries fail from common-cause	1.9E-7	Yes[2, 3]
DCP-BAT-LP-250U1	Unit 1 250 V dc battery fails	2.4E-5	Yes[3]
DCP-BAT-LP-250U2	Unit 2 250 V dc battery fails	2.4E-5	Yes[3]
DCP-BAT-LP-U1	Unit 1 125 V dc battery fails	2.4E-5	Yes[3]
DCP-BAT-LP-U2	Unit 2 125 V dc battery fails	2.4E-5	Yes[3]
DCP-BCH-CF-250ALL	250 Vdc battery chargers fail from common-cause	6.6E-8	Yes[2]
DCP-BCH-CF-CHRS	Battery chargers fail from common-cause	4.7E-8	Yes[2]
DCP-BCH-FC-250U1	Unit 1 250 V dc battery charger 1 fails	2.4E-5	Yes[3]
DCP-BCH-FC-250U12	Unit 1 250 V dc standby battery charger ½ fails	2.4E-5	Yes[3]
DCP-BCH-FC-BCH1	Unit 1 125 V dc battery charger 1 fails	2.4E-5	Yes[3]
DCP-BCH-FC-BCH1A	Unit 1 125 V dc standby battery charger fails	2.4E-5	Yes[3]
DCP-BCH-FC-BCH2	Unit 2 125 V dc battery charger 2 fails	2.4E-5	Yes[3]
DCP-BCH-FC-BCH2A	Unit 2 125 V dc standby battery charger fails	2.4E-5	Yes[3]
DCP-BDC-LP-BUS1A	Division I 125 Vdc bus 1A fails	9.0E-5	No
DCP-XHE-XE-BCH2A	Operator fails to place standby battery charger in service	1.0E-3	No
EPS-DGN-FR-FTRL	Diesel generator fails to run, 14 to 24 hours	0.0	Yes[4]
EPS-DGN-FR-FTRM	Diesel generator fails to run, 0.5 to 14 hours	9.0E-4	Yes[4]
EPS-XHE-XE-BUS-23-1	Unit 2 cross-tie fails from bus 23-1	1.0E-3	Yes[5]
EPS-XHE-XE-BUS-24-1	Unit 2 cross-tie fails from bus 24-1	1.0E-3	Yes[5]
HCI-MOV-IVFRO	HPCI injection valve fails to reopen	2.0E-1	Yes[6]
HCI-MULTIPLE-INJECT	Probability of multiple HPCI injections	1.2E-1	Yes[6]
HCI-XHE-XL-INJECT	Operator fails to recover HPCI injection valve reopening	8.3E-1	Yes[6]

Table 4. Definitions and probabilities for modified or dominant basic events (cont'd).

Event name	Description	Probability/ Frequency	Modified
IE-LOOP	Loss of offsite power initiator	1.0	Yes[7]
OEP-XHE-NOREC-1H	Operator fails to recover offsite power in 1 hour	4.0E-3	Yes[1]
OEP-XHE-NOREC-2H	Operator fails to recover offsite power in 2 hours	4.0E-3	Yes[1]
OEP-XHE-NOREC-4H	Operator fails to recover offsite power in 4 hours	4.0E-4	Yes[1]
OEP-XHE-NOREC-10H	Operator fails to recover offsite power in 10 hours	4.0E-4	Yes[1]
PPR-SRV-OO-1VLV	One SRV fails to close	3.1E-2	No
RHR-XHE-XM-ERROR	Operator fails to start/control RHR	5.0E-4	No
RPS-SYS-FC-CRD	Control rod drive mechanical failure	2.5E-7	No
RPS-SYS-FC-PSOVS	HCU scram pilot SOVs fail	1.7E-6	No
RPS-SYS-FC-RELAY	Trip system relays fail	3.8E-7	No
SDC-LTERM-NOREC2	Operator fails to recover SDC cooling in the long term	3.2E-2	Yes[8]

Notes:

1. Based on human factor evaluation, assuming offsite power is available at time = 0.0 from Unit 1. See Table 5 for human error probability calculations.
2. Common-cause probability values automatically calculated by GEMS.
3. Battery and battery charger failure rate was updated to 1.0E-6/hour, based on guidance provided by Idaho National Engineering Laboratory from NUREG/CR-4550, Table 8.2-8. (Ref. 3). Failure probability of 2.4E-5 based on 24-hour mission time.
4. Diesel generator failure to run probability is based on a total mission time of 1 hour.
5. This event was added to model the ability of operators to cross connect division I bus 13-1 to Unit 2 bus 23-1 and division II bus 14-1 to Unit 2 bus 24-1 (see text and Figure 5 and Figure 8). This event involves different operator action than the operator actions to recover offsite power at Unit 2.
6. Basic events added to fault trees HCI and HC1 to model multiple HPCI injections based on guidance provided by Idaho National Engineering Laboratory.
7. Initiating event frequency changed to model the event being analyzed (see text).
8. Recovery of shutdown cooling in the long term is credited (see text).

Table 5. Human factor evaluation of recovery of ac electrical power.

Recovery event	Time	Stress	Complex	Procedure	Nominal	Adjusted value
LOOP Sequences						
OEP-XHE-NOREC-1H	1	2	2	1	1.0E-3	4.0E-3
OEP-XHE-NOREC-2H	1	2	2	1	1.0E-3	4.0E-3
OEP-XHE-NOREC-4H	0.1	2	2	1	1.0E-3	4.0E-4
OEP-XHE-NOREC-10H	0.1	2	2	1	1.0E-3	4.0E-4
SBO Sequences						
ACP-XHE-NOREC-30	10	5	2	1	1.0E-3	1.0E-1
ACP-XHE-NOREC-90	1	5	2	1	1.0E-3	1.0E-2
ACP-XHE-NOREC-4H	0.1	5	2	1	1.0E-3	1.0E-3
ACP-XHE-NOREC-BD	0.1	5	2	1	1.0E-3	1.0E-3

Table 6. Revised alpha factors for common-cause failure events.

Event name	Event description	Probability	Distribution parameter
DCP-BAT-LP-02A01	250 Vdc battery alpha factor 1 for 2 trains	0.9901068	1.26E+00
DCP-BAT-LP-02A02	250 Vdc battery alpha factor 2 for 2 trains	9.89E-03	1.26E+02
DCP-BAT-LP-04A01	125 Vdc battery alpha factor 1 for 4 trains	0.983541	4.61E+00
DCP-BAT-LP-04A02	125 Vdc battery alpha factor 2 for 4 trains	1.09E-02	2.77E+02
DCP-BAT-LP-04A03	125 Vdc battery alpha factor 3 for 4 trains	4.29E-03	2.79E+02
DCP-BAT-LP-04A04	125 Vdc battery alpha factor 4 for 4 trains	1.24E-03	2.79E+02
ESW-MDP-FR-03A01	Diesel service water motor-driven pump alpha factor 1 for 3 trains (fails to run)	0.9676124	2.41E+01

Table 6. Revised alpha factors for common-cause failure events (cont'd).

Event name	Event description	Probability	Distribution parameter
ESW-MDP-FR-03A02	Diesel service water motor-driven pump alpha factor 2 for 3 trains (fails to run)	1.38E-02	7.34E+02
ESW-MDP-FR-03A03	Diesel service water motor-driven pump alpha factor 3 for 3 trains (fails to run)	1.86E-02	7.31E+02
MCW-MDP-FR-03A01	Circulating water motor-driven pump alpha factor 1 for 3 trains (fails to run)	0.9676124	2.41E+01
MCW-MDP-FR-03A02	Circulating water motor-driven pump alpha factor 2 for 3 trains (fails to run)	1.38E-02	7.34E+02
MCW-MDP-FR-03A03	Circulating water motor-driven pump alpha factor 3 for 3 trains (fails to run)	1.86E-02	7.31E+02
RHR-MDP-FR-04A01	RHR motor-driven pump alpha factor 1 for 4 trains (fails to run)	0.9917641	3.37E+00
RHR-MDP-FR-04A02	RHR motor-driven pump alpha factor 2 for 4 trains (fails to run)	6.70E-03	4.06E+02
RHR-MDP-FR-04A03	RHR motor-driven pump alpha factor 3 for 4 trains (fails to run)	9.90E-04	4.08E+02
RHR-MDP-FR-04A04	RHR motor-driven pump alpha factor 4 for 4 trains (fails to run)	5.45E-04	4.08E+02
RHR-MDP-FS-04A01	RHR motor-driven pump alpha factor 1 for 4 trains (fails to start)	0.9721242	6.89E+00
RHR-MDP-FS-04A02	RHR motor-driven pump alpha factor 2 for 4 trains (fails to start)	2.53E-02	2.41E+02
RHR-MDP-FS-04A03	RHR motor-driven pump alpha factor 3 for 4 trains (fails to start)	1.69E-03	2.47E+02
RHR-MDP-FS-04A04	RHR motor-driven pump alpha factor 4 for 4 trains (fails to start)	9.03E-04	2.47E+02
SSW-MDP-FR-04A01	RHR service water motor-driven pump alpha factor 1 for 4 trains (fails to run)	0.9692023	3.07E+01
SSW-MDP-FR-04A02	RHR service water motor-driven pump alpha factor 2 for 4 trains (fails to run)	1.35E-02	9.83E+02
SSW-MDP-FR-04A03	RHR service water motor-driven pump alpha factor 3 for 4 trains (fails to run)	4.28E-03	9.92E+02
SSW-MDP-FR-04A04	RHR service water motor-driven pump alpha factor 4 for 4 trains (fails to run)	1.31E-02	9.83E+02
SWS-MDP-FR-05A01	Service water motor-driven pump alpha factor 1 for 5 trains (fails to run)	0.9710674	3.64E+01

Table 6. Revised alpha factors for common-cause failure events (cont'd).

Event name	Event description	Probability	Distribution parameter
SWS-MDP-FR-05A02	Service water motor-driven pump alpha factor 2 for 5 trains (fails to run)	1.19E-02	1.24E+03
SWS-MDP-FR-05A03	Service water motor-driven pump alpha factor 3 for 5 trains (fails to run)	5.10E-03	1.25E+03
SWS-MDP-FR-05A04	Service water motor-driven pump alpha factor 4 for 5 trains (fails to run)	1.99E-03	1.25E+03
SWS-MDP-FR-05A05	Service water motor-driven pump alpha factor 5 for 5 trains (fails to run)	9.99E-03	1.24E+03

Attachment A
Electrical Power Recovery Model

- **Background**

The time required to restore offsite power to plant emergency equipment is a significant factor in modeling the CCDP given a loss of offsite power (LOOP). SPAR models for LOOP and station blackout (SBO) include various sequence-specific ac power recovery factors that are based on the time available to recover power to prevent core damage. For a sequence involving failure of all of the reactor cooling sources, only about 30 minutes would be available to recover power to help avoid reactor core damage. On the other hand, for sequences involving successful early inventory control and decay heat removal, but failure of long-term decay heat removal, several hours to recover ac power prior to reactor core damage would be available.

Failure to recover offsite power to plant safety-related electrical loads (if needed because EDGs fail to supply the loads), given recovery of power to the switchyard, could result from (1) operators failing to restore proper breaker line-ups, (2) breakers failing to close on demand, or (3) a combination of operator and breaker failures. The dominant contributor to failure to recover offsite power to plant safety-related loads in this situation is operators failing to restore proper breaker line-ups. The SPAR human error model was used to estimate nonrecovery probabilities as a function of time following restoration of offsite power to the switchyard. The best estimate analysis assumes that at least 30 minutes is necessary to restore offsite power to emergency buses given offsite power is available at time T = 0.0. .

- **Human error modeling**

The SPAR human error model generally considers the following three factors:

- Probability of failure to diagnose the need for action
- Probability of failure to successfully perform the desired action
- Dependency on other operator actions involved in the specific sequence of interest

This analysis assumes no probability of failure to diagnose the need to recover ac power and no dependency between operator performance of the power recovery task and any other task the operators may need to perform. Thus, each estimated ac power nonrecovery probability is based solely on the probability of failure to successfully perform the desired action.

The probability of failure to perform an action is the product of a nominal failure probability (1.0×10^{-3}) and the following eight performance shaping factors (PSFs):

- Available time
- Stress
- Complexity
- Experience/training
- Procedures
- Ergonomics
- Fitness for duty
- Work processes

For each ac power nonrecovery probability, the PSF for available time is assigned a value of 10 if the time available to perform the action is approximately equal to the time required to perform the action, 1.0 if the time available is between two and four times the time required, and 0.1 if the time available is greater than or equal to five times the time required. If the time available is inadequate (i.e., less than the time to restoration of power to the switchyard plus 1 hour for the best estimate case), the ac power nonrecovery probability is 1.0 (TRUE).

The PSF for stress is assigned a value of 5 (corresponding to extreme stress) for all ac power SBO nonrecovery probabilities. The PSF for stress is assigned a value of 2 (corresponding to high stress) for all ac power non-SBO nonrecovery probabilities.

For all of the ac power nonrecovery probabilities, the PSF for complexity is assigned a value of 2 (corresponding to moderately complex) based on the need for multiple breaker alignments and verifications.

For all of the ac power nonrecovery probabilities, the PSFs for experience/training, procedures, ergonomics, fitness for duty, and work processes are assumed to be nominal (i.e., are assigned values of 1.0).

- **Results**

Table 5 presents the calculated values for the ac power nonrecovery probabilities used in the best estimate case analysis.

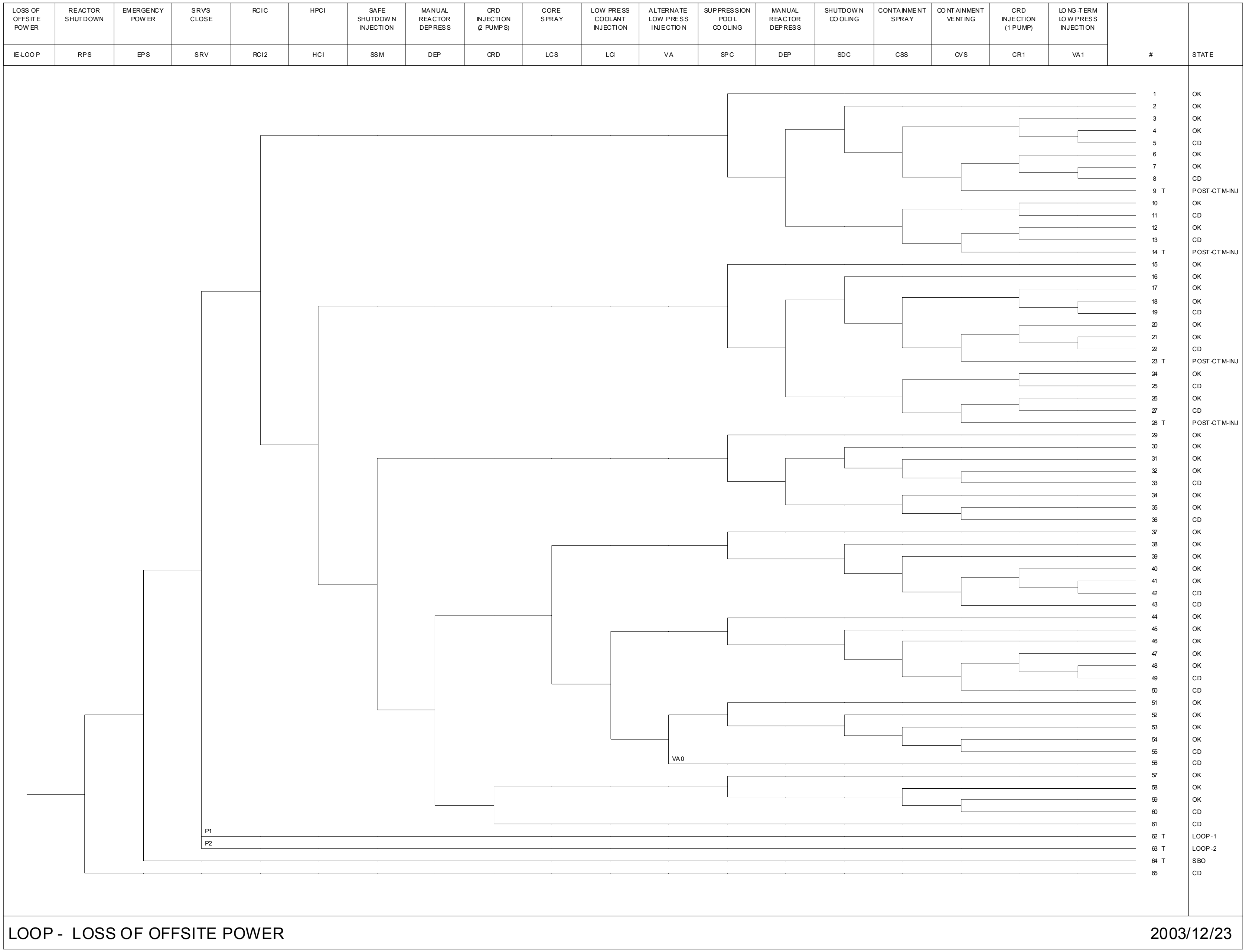


Figure 1. Quad Cities Units 1 and 2 loss of offsite power event tree.

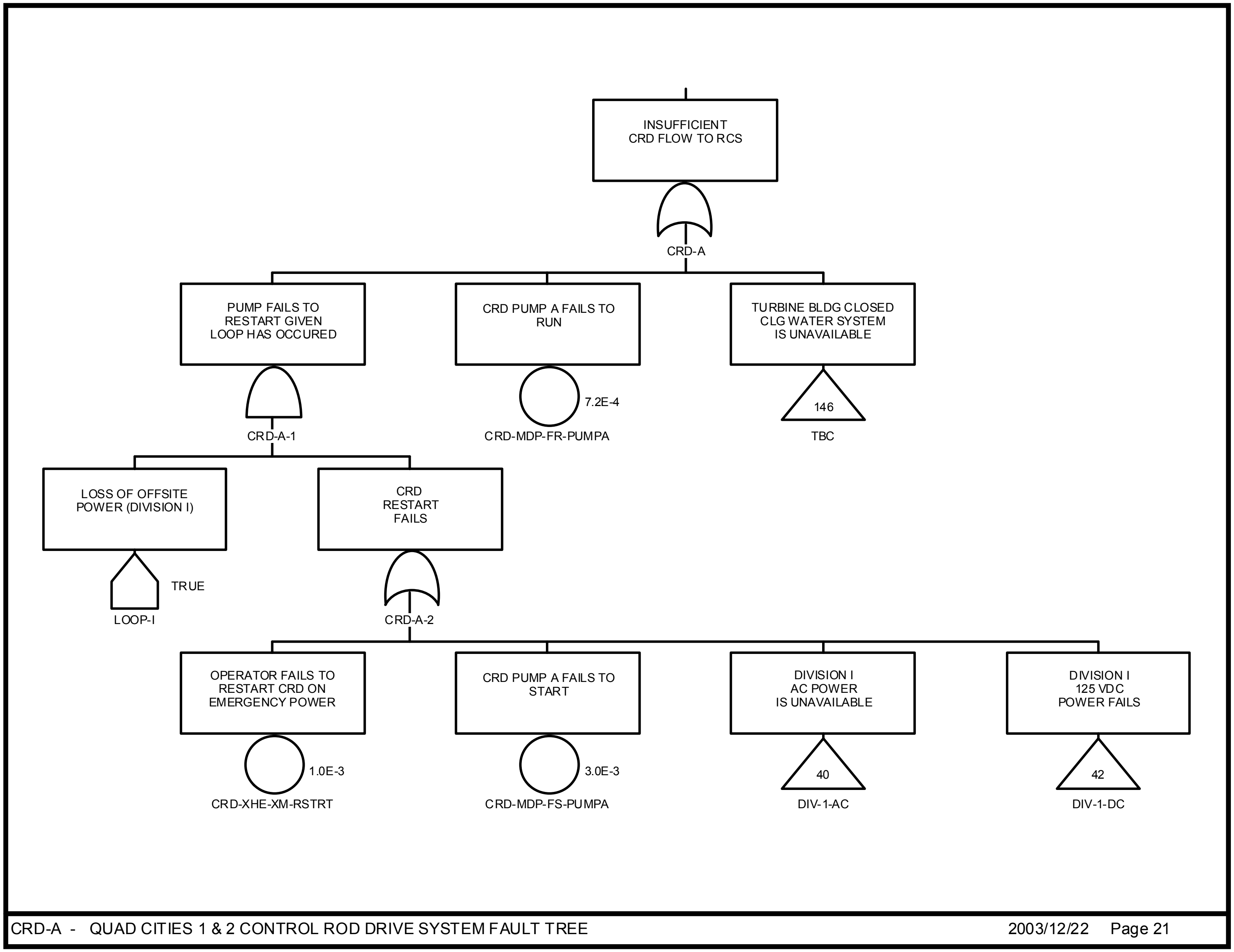
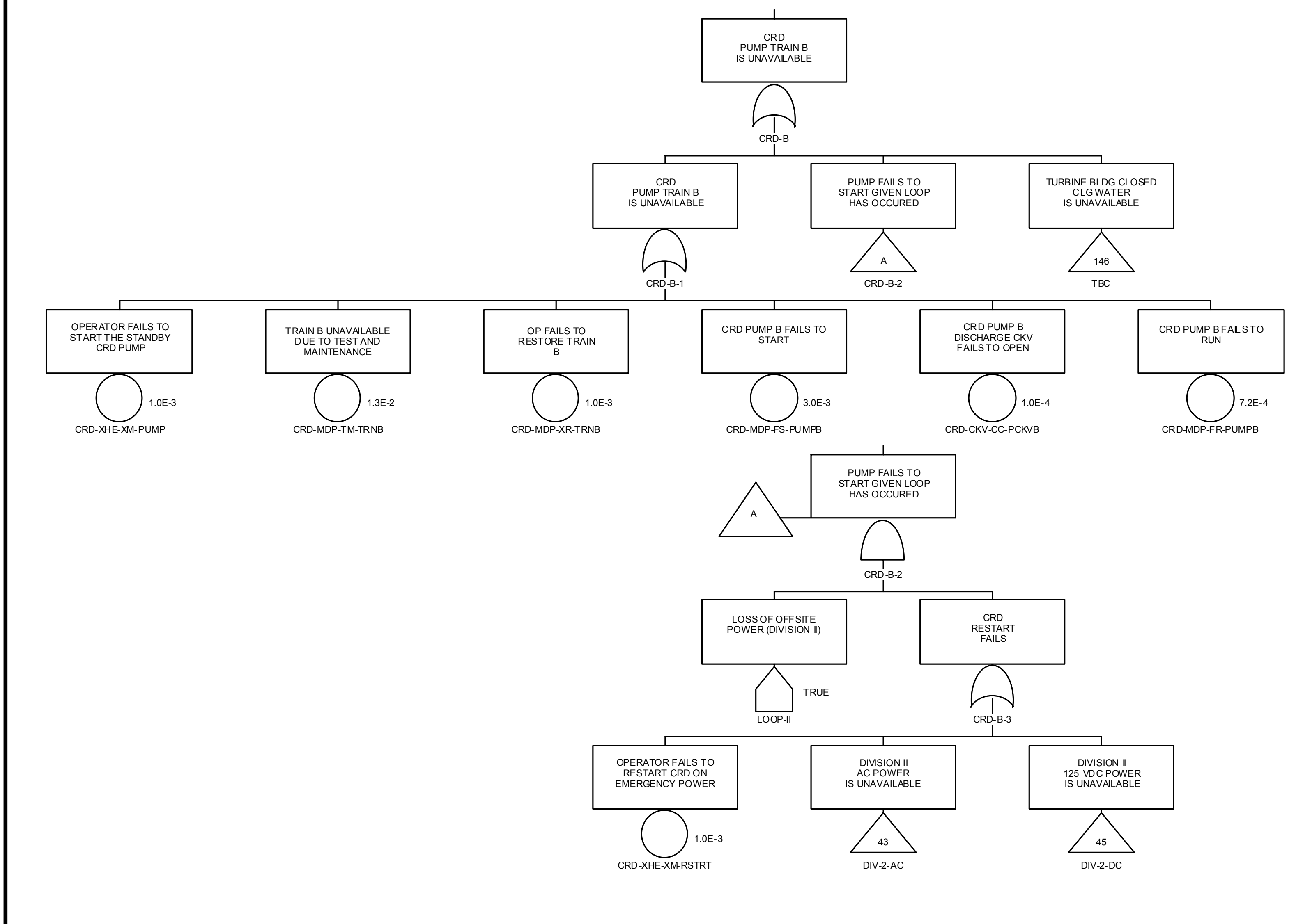
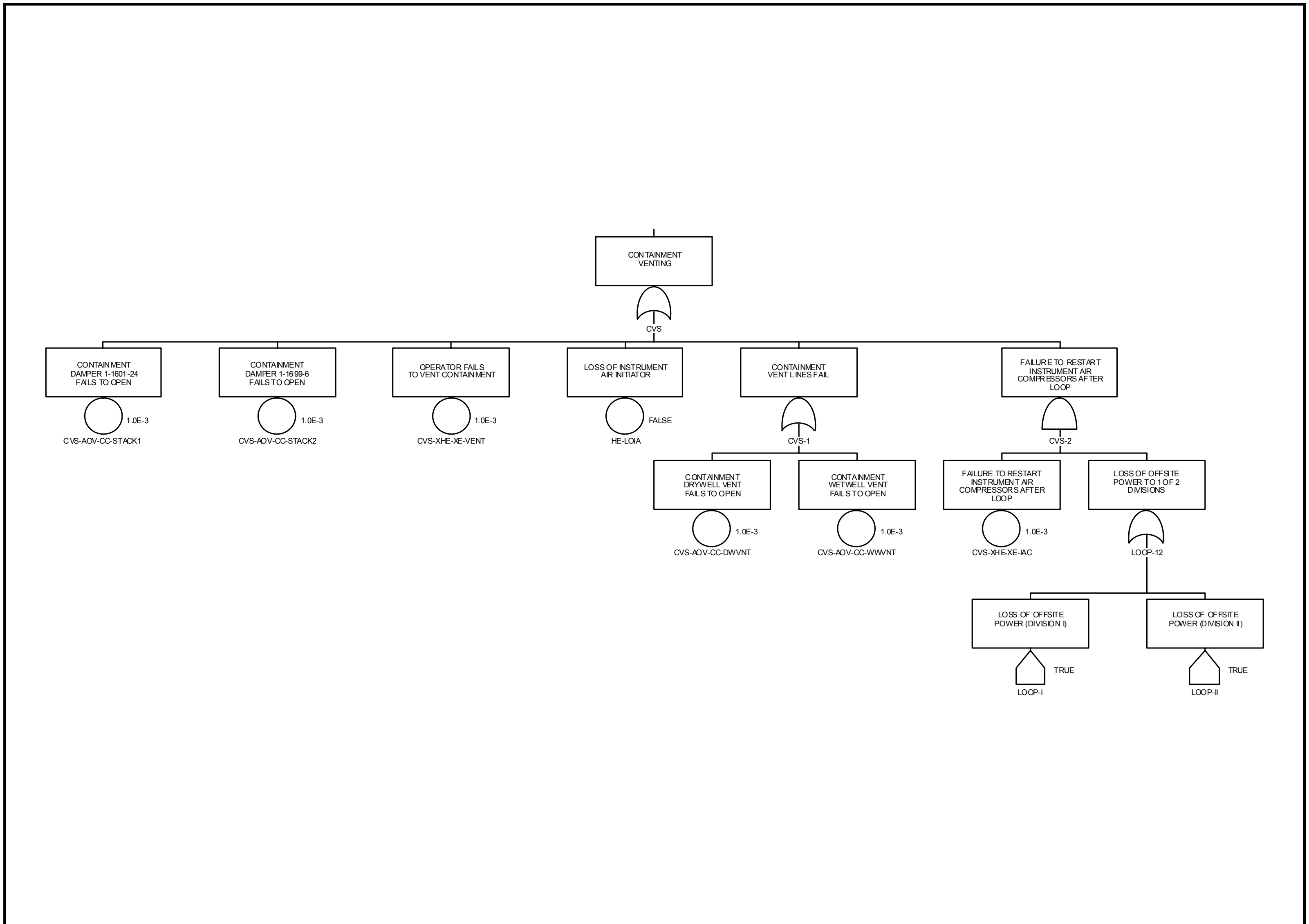


Figure 2. Control rod drive system fault tree (CRD-A).



CRD-B - QUAD CITIES 1 & 2 CONTROL ROD DRIVE SYSTEM FAULT TREE 2003/12/22 Page 22

Figure 3. Control rod drive system fault tree (CRD-B).



CVS - QUAD CITIES 1 & 2 SUPRESSION POOL VENT SYSTEM FAULT TREE 2003/12/22 Page 26

Figure 4. Supression pool vent system fault tree (CVS).

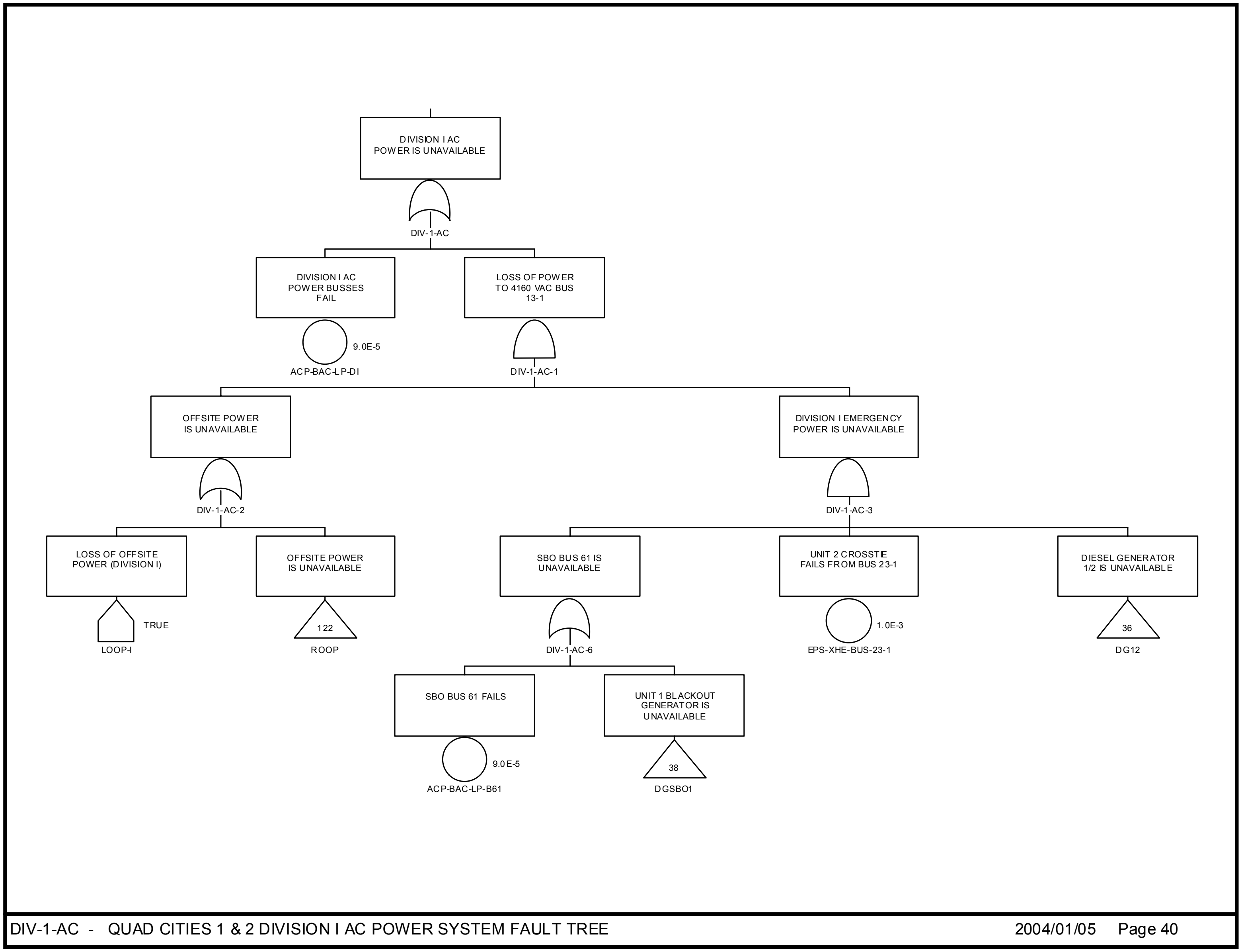


Figure 5. Unit 1 division I ac power system fault tree (DIV-1-AC).

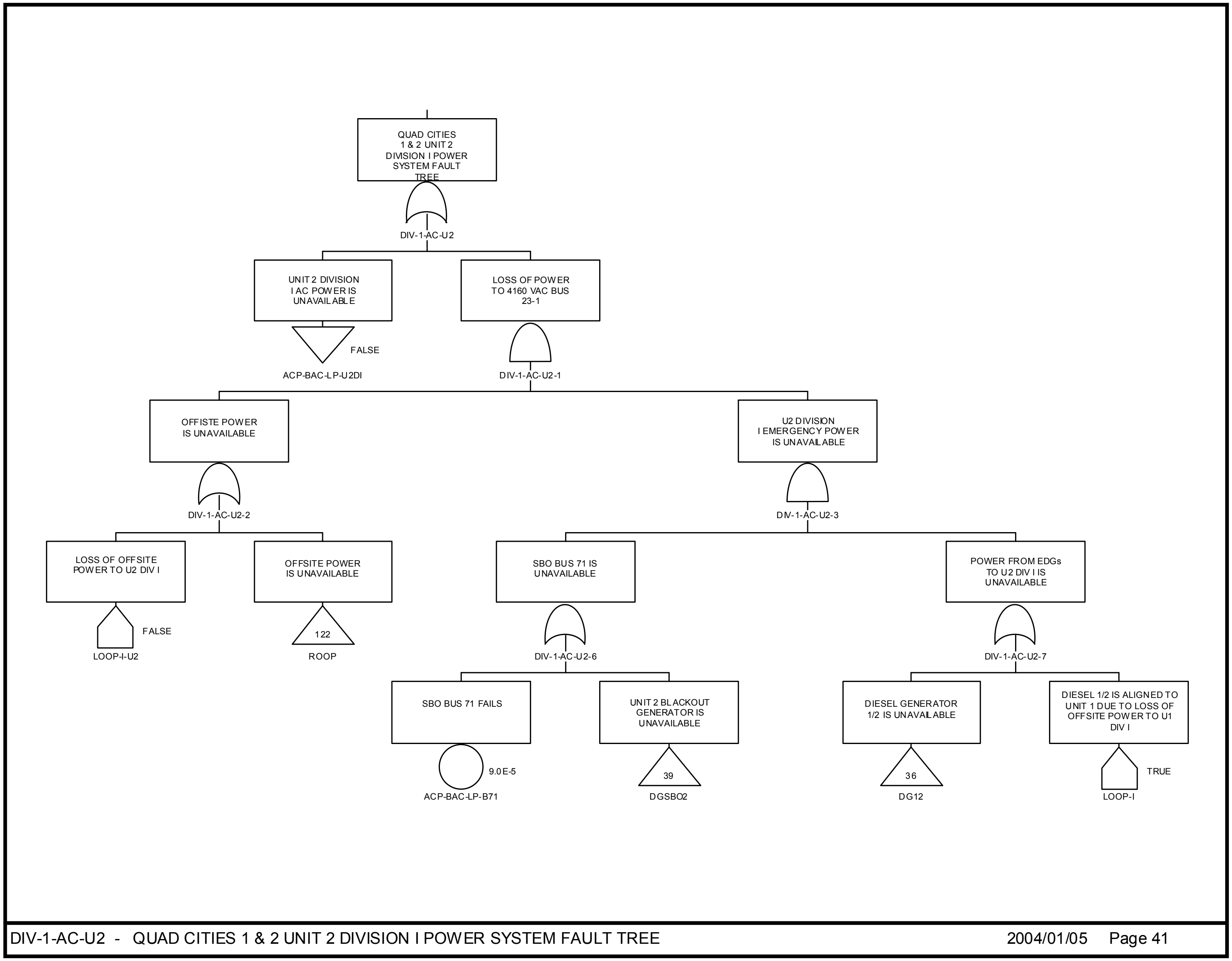
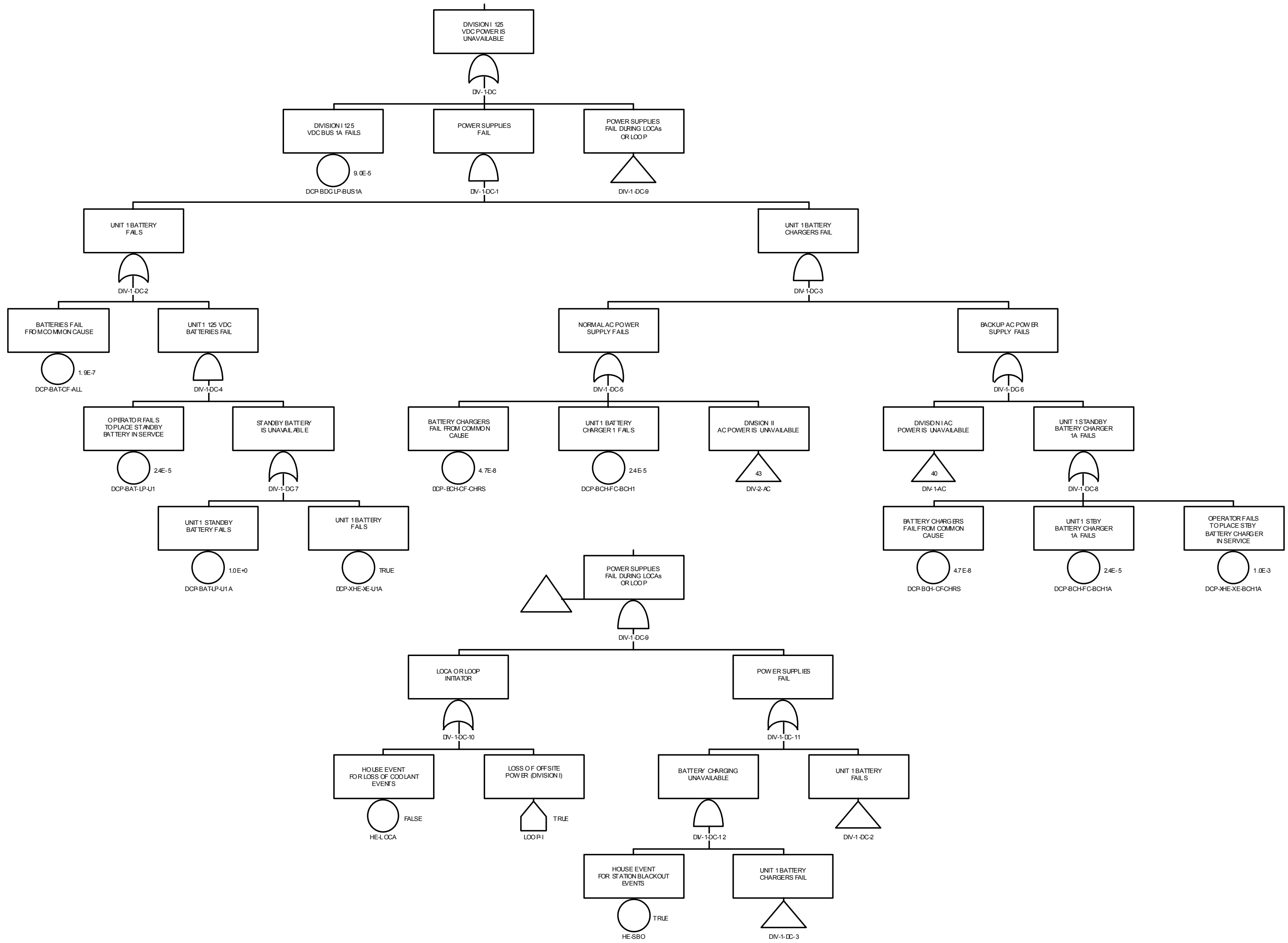


Figure 6. Unit 2 division I ac power system fault tree (DIV-I-AC-U2).



DIV-1-DC - QUAD CITIES 1 & 2 DIVISION I DC POWER SYSTEM FAULT TREE 2004/05/13 Page 42

Figure 7. Unit 1 division I dc power system fault tree (DIV-1-DC).

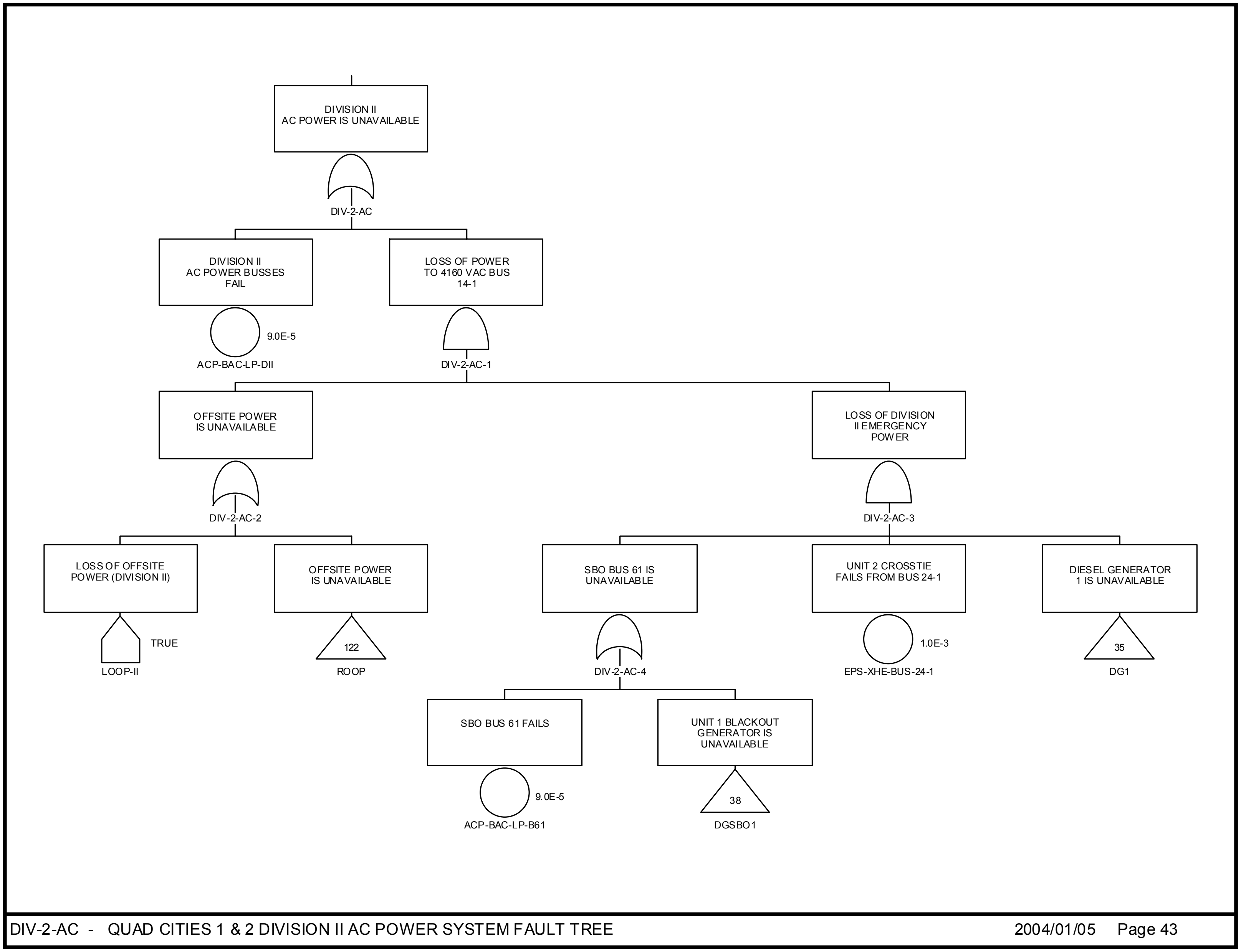


Figure 8. Unit 1 division II ac power system fault tree (DIV-2-AC).

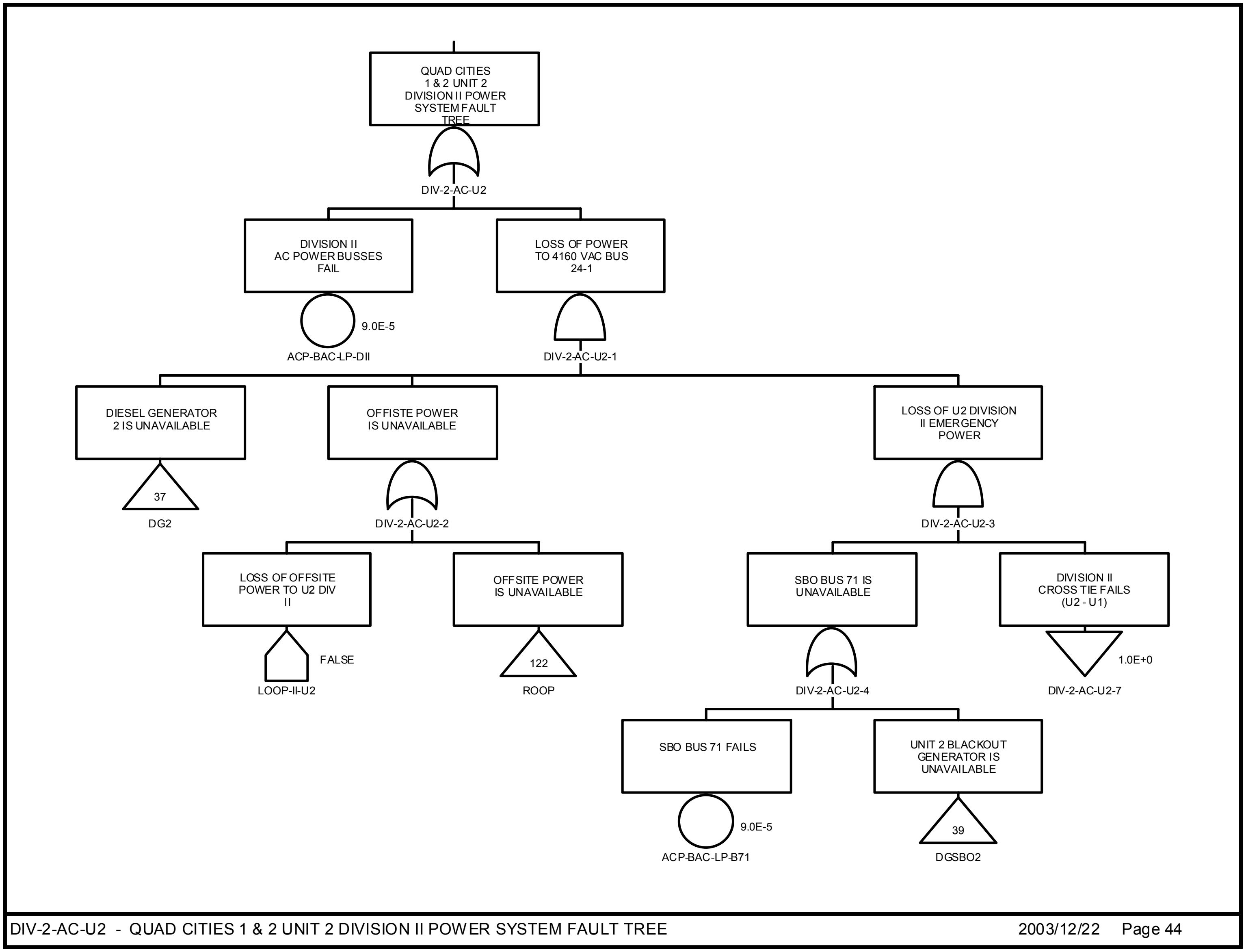
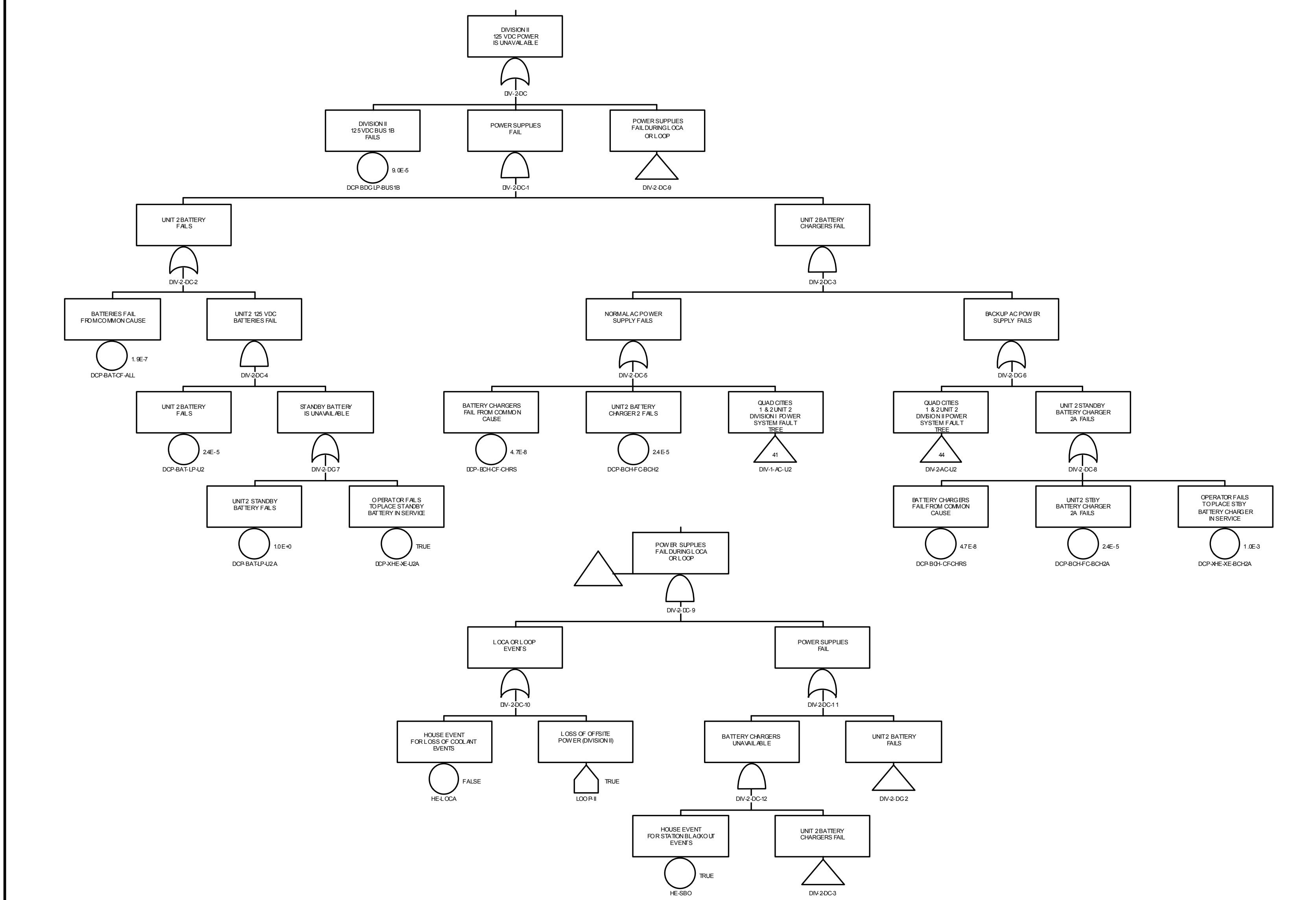


Figure 9. Unit 2 division II ac power system fault tree (DIV-2-AC-U2).



DIV-2-DC - QUAD CITIES 1 & 2 DIVISION II DC POWER SYSTEM FAULT TREE 2004/05/13 Page 45

Figure 10. Unit 1 division II dc power system fault tree (DIV-2-DC).

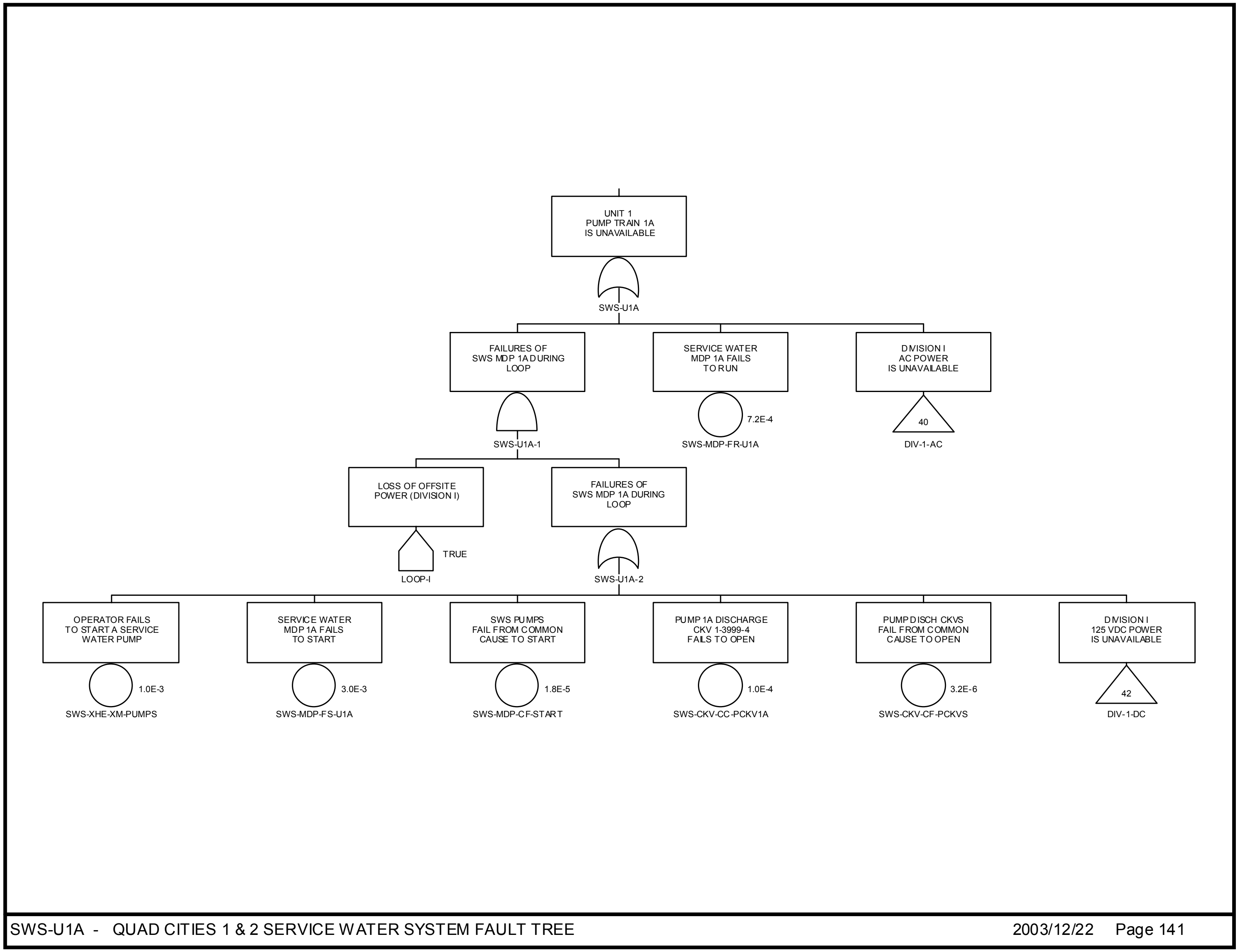


Figure 11. Unit 1 service water system fault tree (SWS-U1A).

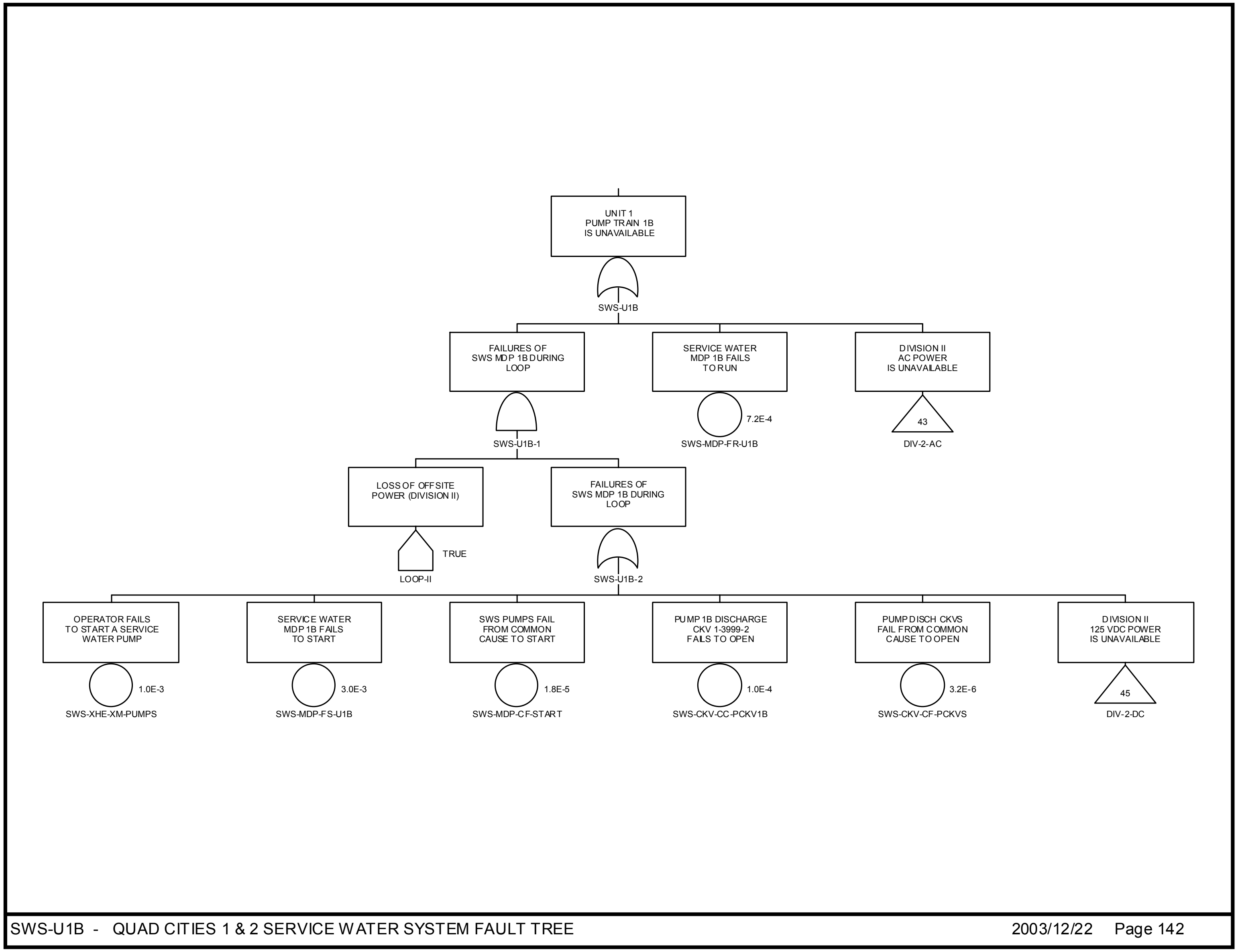


Figure 12. Unit 1 service water system fault tree (SWS-U1B).

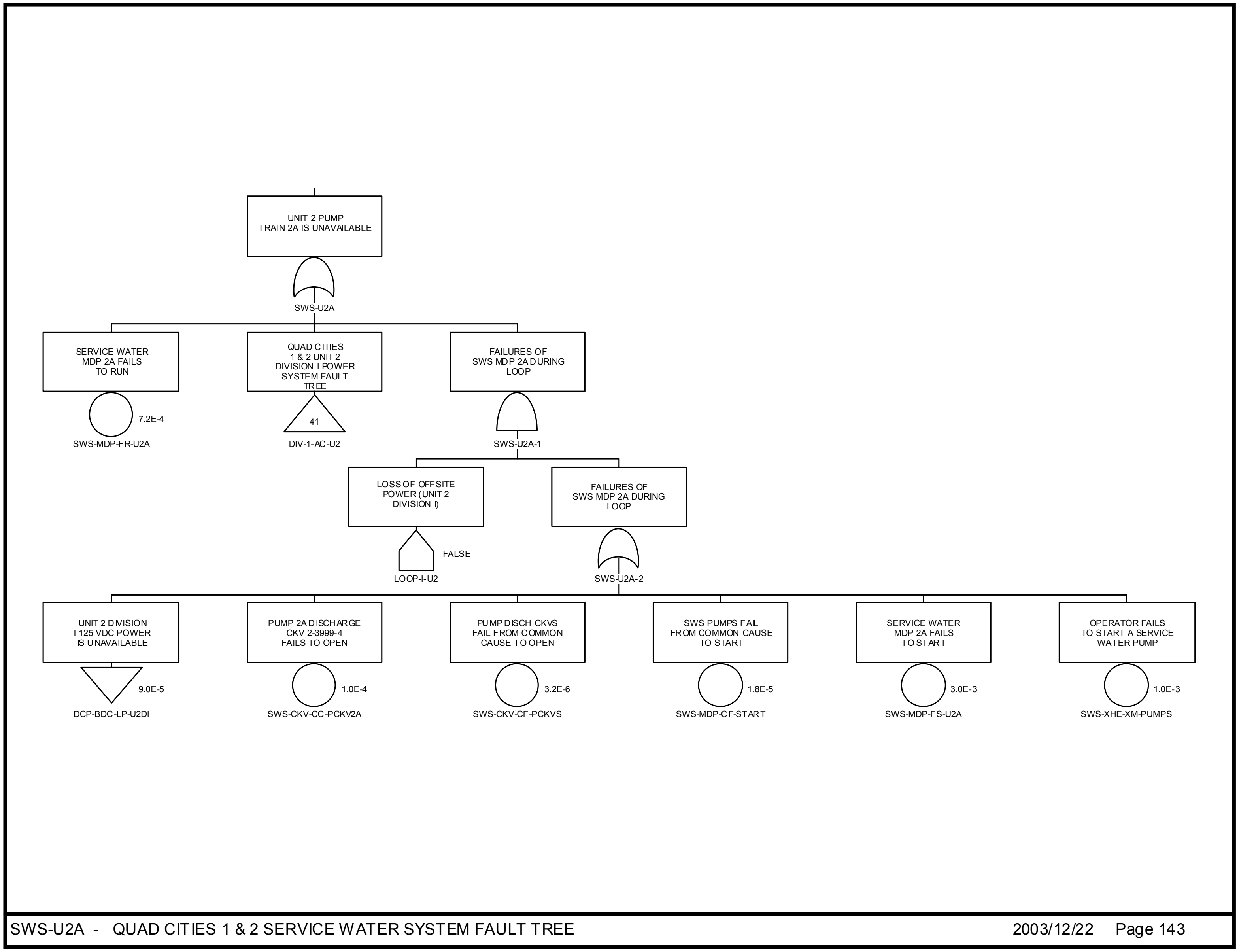


Figure 13. Unit 2 service water system fault tree (SWS-U2A).

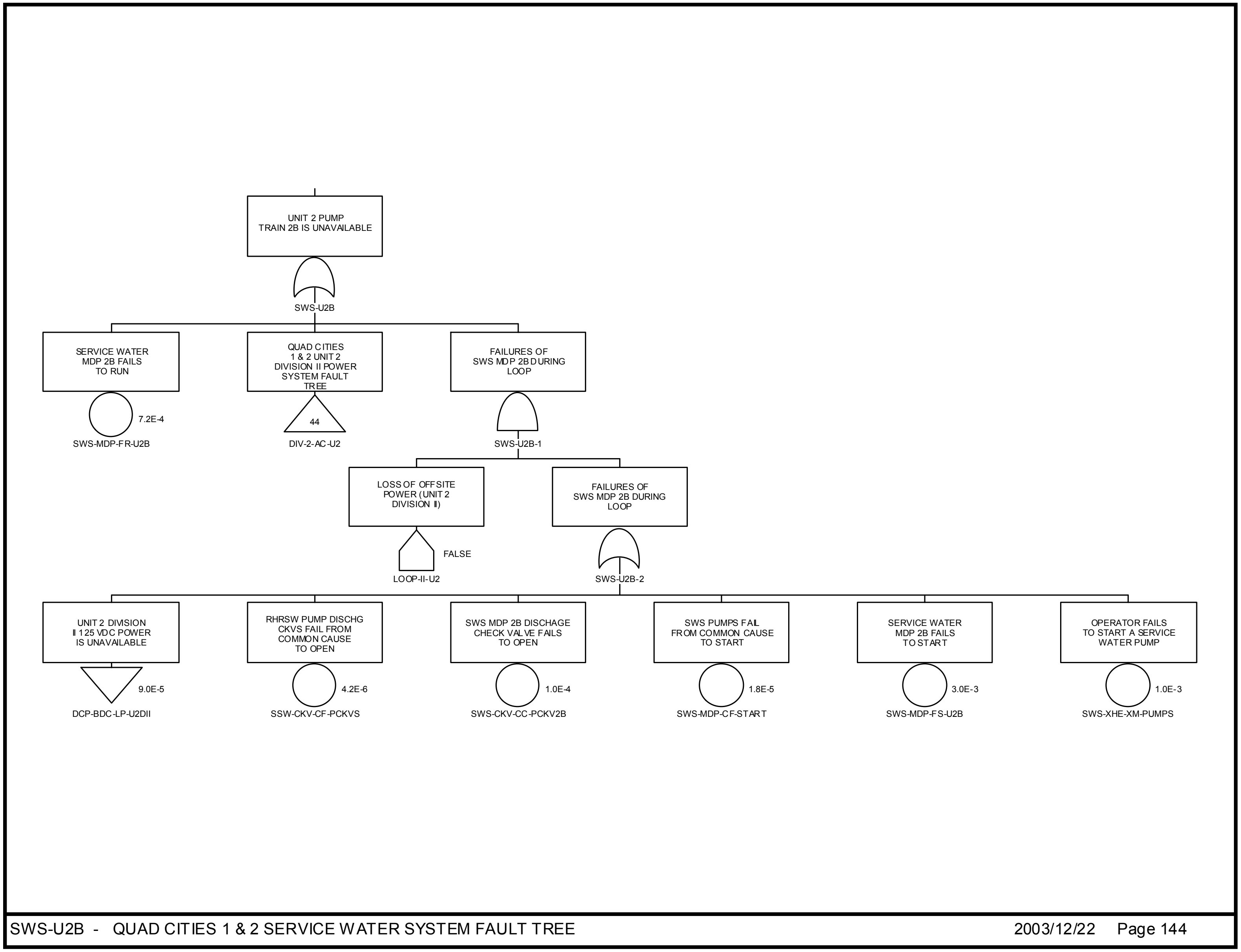


Figure 14. Unit 2 service water system fault tree (SWS-U2B).

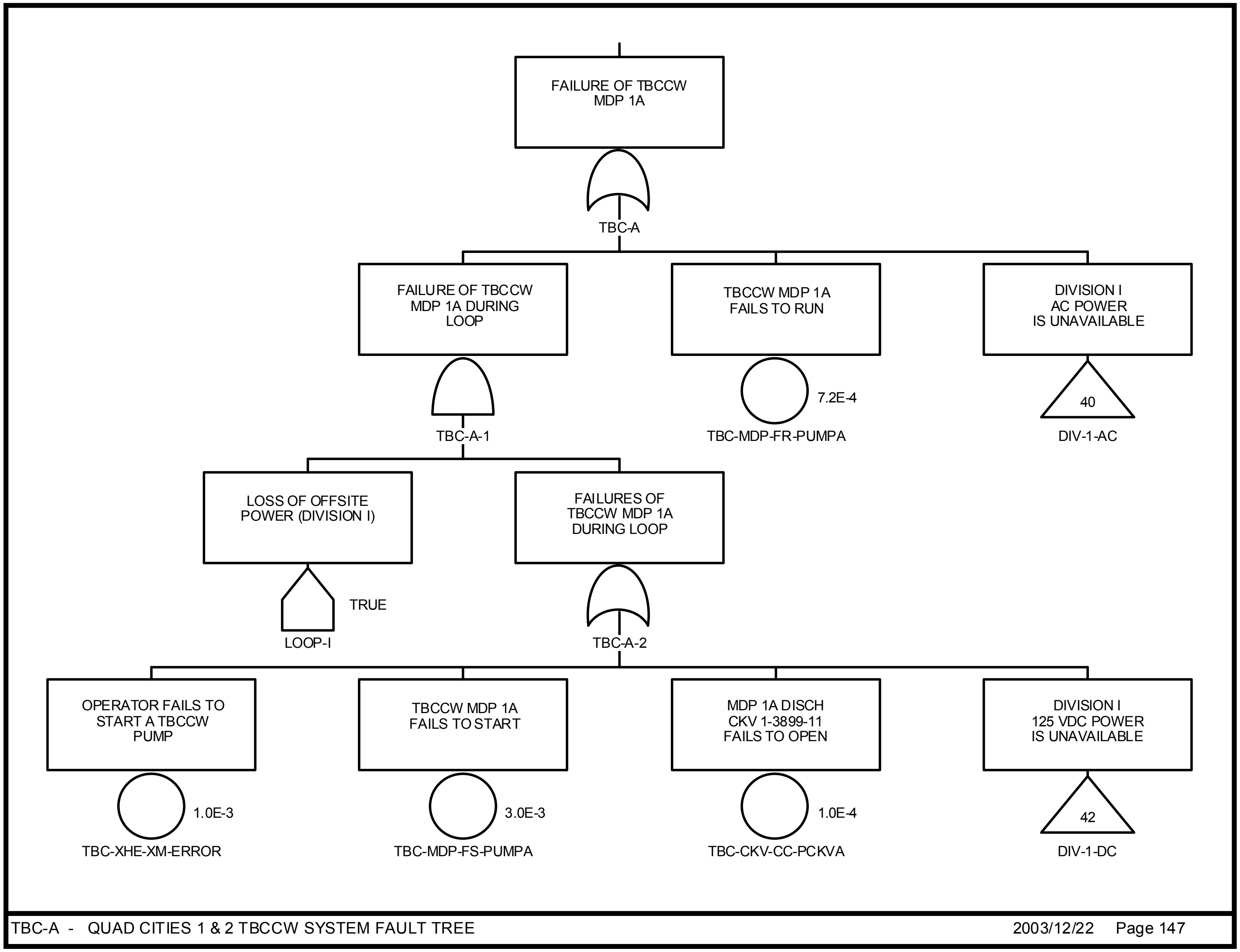
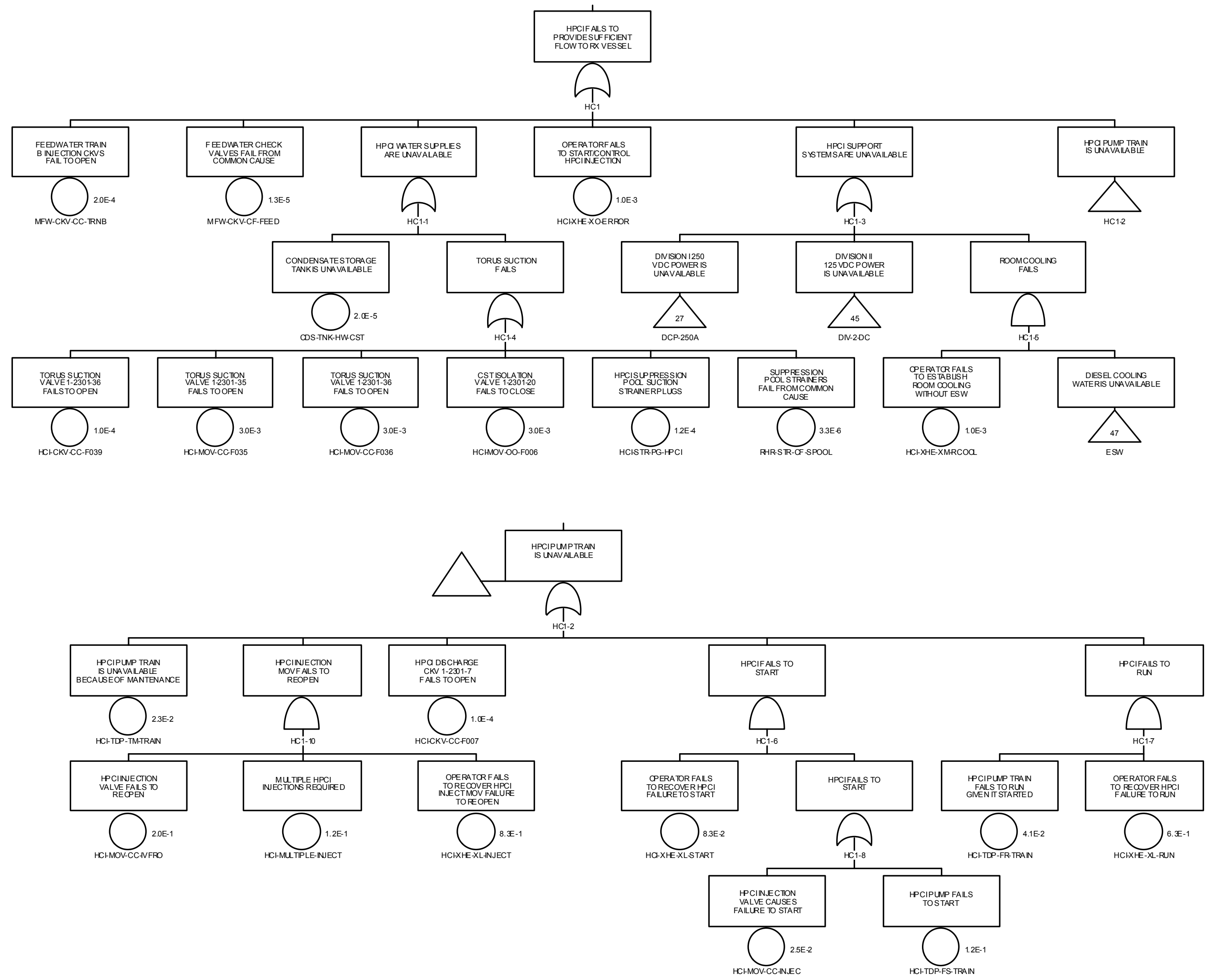
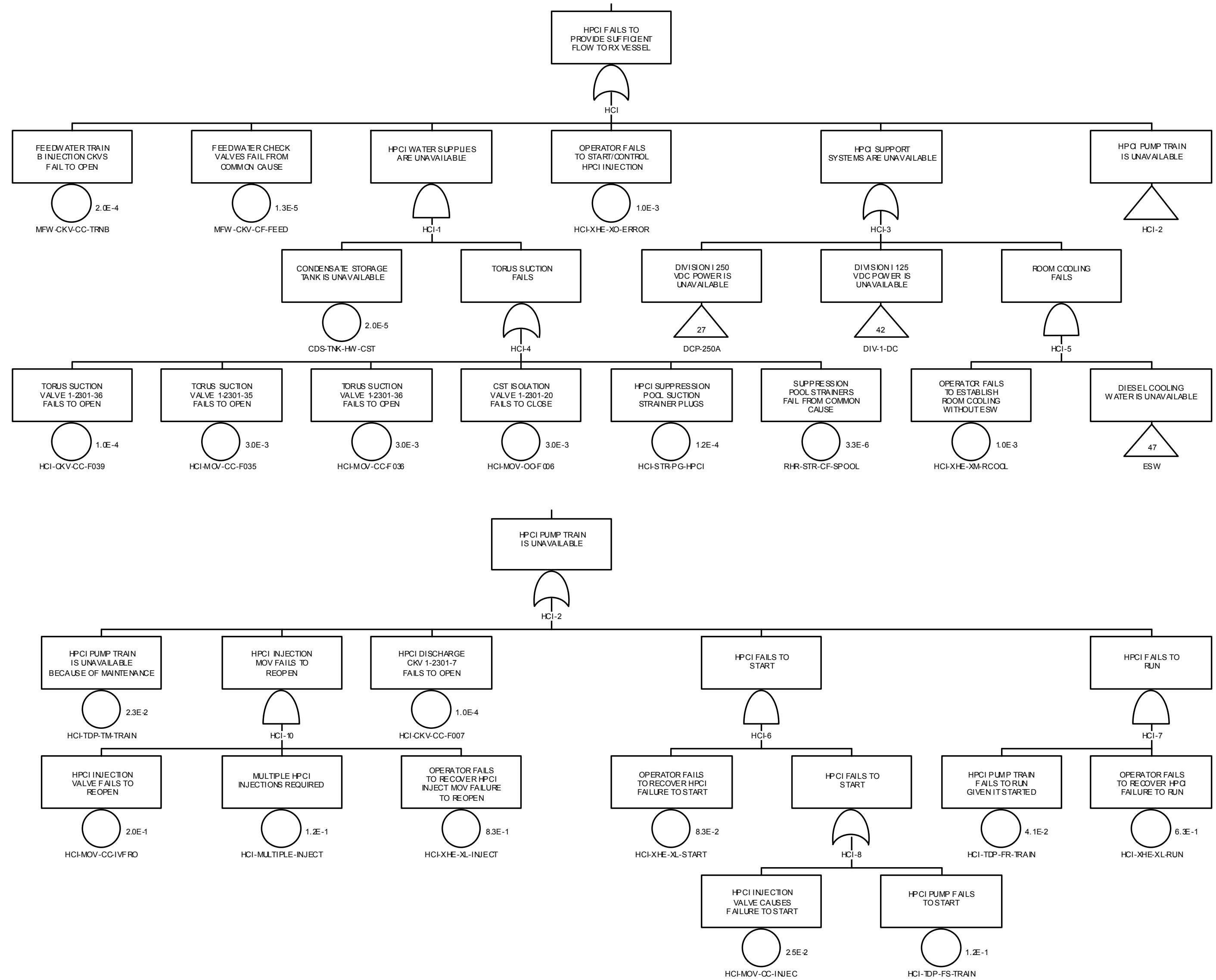


Figure 15. TBCCW system fault tree (TBC-A).



HC1 - QUAD CITIES 1 & 2 HPCI SYSTEM FAULT TREE 2004/05/13 Page 58

Figure 16. HPCI system fault tree (HC1).



HCI - QUAD CITIES 1 & 2 HPCI SYSTEM FAULT TREE 2004/05/13 Page 59

Figure 17. HPCI system fault tree (HCI).

Attachment B - Resolution of Comments

Region III Comments on Accident Sequence Precursor Report for Quad Cities Unit 2 LOOP and Transformer Fire on August 2, 2001

Region III Comment 1: Page 1, Paragraph 1 - Last sentence states (per the LER) that all offsite power sources to Unit 1 remained normal. This statement is somewhat misleading. While Unit 1 remained connected to the grid, the switchyard breakers which opened due to the lightening strike, transformer failure, and switchyard breaker protective relaying malfunctions resulted in 2 of 5 offsite lines being unavailable to both units. In addition, if switchyard breaker 7-8 would have opened Unit 1 would have scrammed since this breaker was the only one allowing power from the Unit 1 main generator to be supplied to the switchyard.

Response: Text changed to state: "Unit 1 remained connected to the offsite grid with a reduced number of offsite power lines."

Region III Comment 2: Page 1, Paragraph 2 - First sentence states that an Unusual Event was declared due to the Unit 2-centered loss of offsite power. I am unsure how this determination was made. Please consider that although the transformer exploded, this event was not what caused the loss of offsite power (LOOP). The LOOP was caused due to a subsequent failure of a switchyard protective relaying reset function. The failure of this relay to properly reset resulted in the switchyard breakers on each side of the relay to open. This is what actually caused the LOOP.

Response: Title changed to "Loss of offsite power to Unit 2 but not Unit 1 due to failure of Unit 2 main power transformer with the subsequent failure of a switchyard breaker relay." Text changed to state: "An unusual event was declared following the Unit 2-centered loss of offsite power (LOOP)."

Region III Comment 3: Page 1, Paragraph 2 - At the bottom of the paragraph, references are made to the Unit 1 EDG and to bus 14-1. The reason for including this information is not clear to me. We may want to better explain that Quad Cities had an opportunity to supply Unit 2 using the grid using the cross tie breaker between bus 14-1 (Unit 1) and bus 24-1 (Unit 2). However, this is not an easy task. To complete this task, the droop setting on the EDG has to be lowered, the EDG has to be paralleled with the grid, the bus tie breaker has to be closed, and several other actions must be done. The licensee chose not to pursue this route since there was no damage to the Unit 2 reserve auxiliary transformer (RAT). The licensee believed it was a better choice to restore the Unit 2 RAT than complete the actions to cross tie busses 14-1 and 24-1.

Response: This paragraph describes the state of all the emergency buses and emergency diesel generators at the site, including the station blackout diesels. The Unit 1 emergency diesel generator and bus 14-1 are described for completeness. Text changed to state: "The Unit 1 EDG (EDG 1) was not required to start ..."

Region III Comment 4: Page 1, Paragraph 3 - Second sentence states that reactor pressure was controlled using the main steam relief valves. Do we mean the safety relief valves or the main steam safety valves? Both types of valves exist at Quad Cities. Based on my plant knowledge, I believe we mean the safety relief valves.

Response: Text unchanged. Text is taken verbatim from the LER. It appears that main steam relief valves and safety relief valves are interchangeable nomenclature.

Region III Comment 5: Page 1, Paragraph 4 - Multiple local fire departments were called in to combat the transformer fire.

Response: Text changed to state: "...and (3) actions of the local fire departments."

Region III Comment 6: Page 1, Paragraph 5 - Unit 1 did not continue to operate at 100 percent power throughout the event. As stated in Inspection Report 2001012, Unit 1 reactor power was lowered to approximately 93 percent during the Unit 2 transformer fire to recover service water system pressure.

Response: Text changed to state: "Unit 1 power was lowered to approximately 93% following the LOOP at Unit 2."

Region III Comment 7: Page 2, Paragraph 1 - While we do not disagree with the information in this paragraph, more is known. Specifically, the Unit 2 main power transformer was subjected to multiple electrical faults during its service life. Although the licensee knew about the faults, they were not tracking the number of faults or the severity of the faults on the transformer. The licensee now states that repeatedly subjecting the undersized bus bar and bus bar clamps to faults caused these components to loosen to the point that a phase-to-phase fault occurred in the transformer.

Response: Text changed to state: "...caused a fire in the transformer. The Unit 2 main power transformer was subjected to multiple electrical faults during its service life, which contributed to its ultimate failure. Although the licensee knew about the faults, they were not tracking the number of faults or the severity of the faults on the transformer."

Region III Comment 8: Page 2, Paragraph 1 - In their LER, the licensee stated that age related degradation of a transistor led to slow reset time of the static breaker failure relay. Again, this is a true statement. However, the licensee failed to state that the age related degradation was not recognized earlier due to the failure to include completion of the reset function in their relay testing program.

Response: Text changed to state: “...causing a slow relay reset time (Ref. 1). The age-related degradation was not recognized earlier due to the failure to include completion of the reset function in their relay testing program.”

Region III Comment 9: Page 2, Paragraph 2 - The LOOP was not caused by the transformer failure. It was a direct result of the static breaker failure relay malfunction.

Response: Text changed to state: “For Unit 2, the event is considered a unit-centered LOOP caused by failure of a switchyard breaker relay to properly respond to failure of the Unit 2 main power transformer.”

Region III Comment 10: Page 2, Paragraph 3 - This paragraph mentions that Unit 1 had restricted electrical power while offsite power was being restored to Unit 2. This contradicts Page 1, Paragraph 5 which states that Unit 1 remained at full power. Also, electrical power was restricted to recover service water pressure rather than to restore power to Unit 2.

Response: Text unchanged. The text on page 1, paragraph 5 was changed as noted above.

Region III Comment 11: Page 2, Paragraph 4 - Please consider including the information mentioned on the previous page to explain why the licensee chose not to restore offsite power to Unit 2 using the Unit 1 cross tie. If a decision is made not to include this information, please consider explaining why the NRC feels this would have been a better course of action.

Response: Text unchanged. The ASP analysis is based on what occurred. No judgment is being made as to which action is better. The decision concerning when to restore offsite power must be made by the operators on site depending on the existing conditions.

Region III Comment 12: Page 2, Paragraph 6 - Under the CCDP analysis results section, please consider including the precursor threshold value for an initiating event to provide the reader with a baseline initiating events value.

Response: Text changed to state: “This CCDP exceeds the Accident Sequence Precursor (ASP) acceptance threshold. The CCDP is greater than 1.0×10^{-6}, and the CCDP is greater than the CCDP for a transient with loss of reactor feedwater and no reactor feedwater recovery, which is 1.2×10^{-6} (point estimate).”

Region III Comment 13: General Comments - You may want to consider looking at the inspection reports in addition to the licensee’s LER. I have found that the licensee tends to only include what is required while providing as little information as possible to the reader. You may find that the inspection reports include more detail on what happened during a specific event and why.

Response: Review of inspection reports has always been a part of the Accident Sequence Precursor program.

A memo from Peter J. Habighorst, Acting Section Chief, Probabilistic Safety Assessment Branch, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation to Larry Rossbach, Project Manager, Division of Licensing Project Management, Office of Nuclear Reactor Regulation, dated July 7, 2004, "Review of Preliminary ASP Analysis of a Loss of Off-Site Power Event at Quad Cities in August 2001."

SPSB Comment 1: Generic Comment - In the event summary, the lightning strike caused the Unit 2 main transformer failure, leading to an automatic shutdown of the Unit 2 reactor. Subsequently, additional breakers in the switchyard supplying offsite power to the Unit 2 reserve auxiliary transformer (RAT) opened, and an unusual event was declared due to the Unit 2 loss of offsite power (LOOP). If the above two events concurred or the breaker openings followed the weather-initiated transformer fire instantly, the event was initiated due to severe weather (lightning strike), leading to a partial LOOP (or transient) and followed by the total loss of offsite power due to the subsequent failures of the breakers.

Response: Analysis was performed as a unit-centered LOOP on Unit 2; that is, only Unit 2 lost offsite power while Unit 1 remained tied to offsite power. Modifications were made to the SPAR Revision 3 models to perform the analysis as a Unit 2-centered LOOP. The nominal SPAR Revision 3 initiating events do not apply to this event. In particular, the SPAR Revision 3 plant-centered LOOP model does not apply because not all units at the site lost offsite power due to problems in the switchyard.

SPSB Comment 2: Generic Comment - The PSFs for recovery actions have been changed. The assignment of either an overly conservative stress level (such as "extreme" stress) or a too optimistic value may not be desirable, depending on the PSFs and type of precursor events. Two PSFs, 'stress' and 'complex' for LOOP sequences have been changed from "nominal" to "high" and "nominal" to "moderately complex," respectively. These adjusted recovery actions raised the CDP contribution by a factor of four. For a routine LOOP event with a well defined plant evolution, "normal" stress level may be more appropriate. The PSFs for this event should be set to "nominal" values.

Response: Based on a number of evaluations of LOOPs over the last 3 years, including the grid-related LOOPs on August 14, 2003, the Accident Sequence Precursor program reviewed its treatment of recovery of electrical power following LOOP and made some changes to the methods used for the analysis. For LOOPs and partial LOOPs, recovery of electrical power is now generally treated as a human factor evaluation rather than allowing the SPAR Revision 3 models to automatically recalculate recovery based on what kind of LOOP was specified in the computer input. The ASP analysis for Quad Cities Unit 2 represents an event where Unit 2 lost offsite power but Unit 1 did not. The ability to recover electric power at Unit 2 using Unit 1 electrical power existed from time t = 0.0 seconds. The performance shaping factors used in the analysis are consistent with other LOOP evaluations, including evaluations of the grid-related LOOPs on August 14, 2003. These performance shaping factors used in LOOP analyses have been approved by human factors personnel at INEEL.

SPSB Comment 3: Generic Comment - For SBO sequences, PSF values were changed from "nominal" to either "more-than enough" or "inadequate" for the PSF element, 'time,' and to "extreme" for the PSF 'stress'. These changes appear to be too extreme, compared with the changes for the recovery actions during the LOOP sequences. Again, these changes may not be appropriate.

Response: The analysis represents an event where Unit 2 lost offsite power but Unit 1 did not. The performance shaping factors used in the analysis are those appropriate to the event and use assumptions consistent with other LOOP evaluations. These performance shaping factors have been approved by human factors personnel at INEEL.

SPSB Comment 4: Generic Comment - The reviewer employed the Quad Cities SPAR-3 model for initiation and condition evaluation of this ASP event and all of the initial availability numbers were set to nominal values without changing or adjusting PSFs and basic event availability numbers. The availability values of the reactor protection system (RPS) and other successful systems were set as nominal values (not "False" or "0"). This resulted in: CDP

Point Estimate	4.6×10^{-5}
Mean	5.4×10^{-5}
5_{th} Percentile	3.4×10^{-5}
Median	4.3×10^{-5}
95_{th} Percentile	1.0×10^{-4}
Standard Deviation	6.6×10^{-6}

* The analyses were based on a truncation level of 10^{-11} with the third and fourth moments indicating relatively high uncertainty.

Response: In general, the SPSB results appear to result in a CCDP an order of magnitude higher than the ASP results. The differences are due to a number of considerations, but the major reasons for the differences are believed to be: (1) the nominal SPAR Revision 3 initiating events are not applicable to the event at Quad Cities and (2) the SPSB analysis does not take credit for the ability of the operators to restore electrical power in ways not treated in the nominal SPAR Revision 3 models.

SPSB Comment 5: Specific Comment - The Quad Cities event in August 2001 appeared to be a severe weather related partial LOOP or transient event, unless a plant centered LOOP can be justified. Using nominal values without adjusting the PSF values (Table 5, page 15) and without any credits to successes (zero maintenance model), a plant centered LOOP resulted in a CDP point estimate of 1.1×10^{-4}. Event tree sequence 09-5 is the dominant sequence, followed by sequences 61 and 65. However, the CCDP of sequence 65 remains as 2.4×10^{-6}, since the sequence involves only the reactor protection system (RPS-SYS-FC-PSOVS, RPSSYS- FC-RELAY, and RPS-SYS-FC CRD). If the lightning strike and severe weather related LOOP (not partial LOOP nor Transient) is employed, a CDP point estimate of 4.6×10^{-5} would result. The dominant sequence would be 09-5, followed by sequences 64-02 and 62-34. Sequence 65 would not register in the severe weather related LOOP evaluation as one of the top sequences.

Response: The event is not a plant-centered LOOP. Unit 1 did not lose offsite power. The event is a unit-centered LOOP at Unit 2 and is modeled as such in the ASP analysis using the latest techniques for LOOP analysis.

SPSB Comment 6: Specific Comment - The event summary description indicated that the Unit 2 LOOP lasted approximately 2.5 hours. A more realistic approach of recovery actions could benefit the ASP program. The use of actual offsite power (OSP) restoration time to a safety bus should be more realistic, rather than using a recovery time of more than four hours, which is too conservative.

Response: Offsite power was available to Unit 2 from Unit 1 from time t = 0.0 seconds. The operators chose to allow the emergency diesel generators to continue to power the Unit 2 emergency buses rather than restore electrical power to the Unit 2 emergency buses using Unit 1 electrical power. There were no failures to start or to run of either emergency diesel generator used to power the Unit 2 emergency buses during the event. When the Unit 2 offsite power was restored, the operators restored offsite power to the Unit 2 emergency buses and stopped the emergency diesel generators.

Assuming that an emergency diesel generator powering a Unit 2 emergency bus failed, with a nominal probability, the ASP analysis modeled those operator actions necessary to recover electric power to the emergency bus. Models were created that considered that electric power was available to supply Unit 2 from Unit 1 at time t = 0.0 seconds if a Unit 2 emergency diesel generator were postulated to fail. Probabilities were generated for recovery of electrical power at various recovery times (30 minutes, 60 minutes, 90 minutes, etc.) using techniques applicable to human error analysis. The actual recovery of Unit 2 offsite power at 2.5 hours is not significant to the analysis and is not included in the ASP analysis.

SPSB Comment 7: Specific Comment - In the modeling assumptions and assessment summary, the event description employed a term, “a unit-centered” LOOP initiating event. To be consistent with the nomenclature used in the reports for individual plant SPAR models, the term “plant centered” may be more appropriate instead of the “unit-centered” term.

Response: The event is not a plant-centered LOOP. Unit 1 remained tied to the offsite power grid. The SPAR Revision 3 model was modified to fit the conditions where Unit 2 lost offsite power but Unit 1 remained tied to the offsite grid.

SPSB Comment 8: Specific Comment - Changes to basic event probability and common cause failure events were made as documented in Tables 4 through 6. The performance shaping factors (PFSs) were revised to elevate operators’ ‘stress’ and ‘complex’ for both LOOP and SBO. Why not assign them normal or nominal numbers?

Response: See response to SPSB Comment #2 and SPSB Comment #3.

SPSB Comment 9: Specific Comment - Headings in Table 6 appeared to be misleading. The first column heading in Table 6 should be "Alpha Identifier" instead of "Alpha Factor." Also, it would be beneficial to insert "Alpha Distribution Parameter" in the last column with the beta factor. These changes will make Table 6 more consistent with the other SPAR reports.

Response: The headings in Table 6 have been revised to be consistent with Table B-1 in the documentation of the SPAR Model for Quad Cities 1 & 2 (ASP BWR C).

SPSB Comment 10: Specific Comment - The switching over to the alpha factor from the beta factor was not clearly defined in the report. The rationale of the change should be documented and included. As an example, the change may be needed for the uncertainty analysis. Also, both probability and the beta numbers were changed and different from the numbers listed in the SPAR 3i report. The changes were based on the upgrading of the numbers by INEEL. However, it would be helpful for readers to include a short explanation of the technical bases for changing the values.

Response: For certain basic events, the latest values recommended by INEEL were used in the analysis. Documentation of the changes will be included in the next revision of the SPAR report published by INEEL. In the meantime, questions concerning the changes should be addressed to the NRC Office of Research.

SPSB Comment 11: Specific Comment - The sensitivity study of non recovery probability is summarized on page 9. It may help to explain the objective of this study and the reason for assuming the non recovery probability could be 10 times greater.

Response: The sensitivity study is not an uncertainty analysis. The study did not mean to imply that the nonrecovery factor could actually be 10 times greater. The sensitivity study just indicates that the CCDP would change by the amount indicated if the basic event were changed to a factor of 10 higher. The text has been changed to state: "... A sensitivity study was made using a value of 1.6E-1 for SDC -LTERM-NOREC2. With this change, the CCDP value ..."

A letter from Patrick R. Simpson, Exelon Nuclear, to the NRC, dated July 9, 2004, Quad Cities Nuclear Power Station, Unit 2, "Response to Review of Preliminary Accident Sequence Precursor Analysis of August 2, 2001, Operational Event"

Licensee's Comment 4.1: As calculated by the EGC PRA for QCNPS Unit 2, the CCDP for single-unit loss of offsite power is 4.7×10^{-6}. Therefore, the QCNPS PRA supports the NRC Staff conclusion that this event qualifies as an ASP.

Response: No response is required.

Licensee's Comment 4.2: It is interesting to observe that none of the dominant cutsets for the LOOP initiator have anything to do with failure of AC power. This points out the strength of the QCNPS AC power system. What makes the LOOP much worse than an ordinary turbine trip, however, is the loss of power to turbine building systems such as feedwater and turbine bypass valves.

Response: No response is required.

Licensee's Comment 4.3: Because QCNPS is a two-unit station that shares several non-safety-related support systems between the units, and because Unit 1 remained online with its normal source of offsite power, the impact of the LOOP is smaller than would be true for a single-unit station. For example, instrument air remained available and non-essential service water remained available. Therefore, motive air remained available for containment vent valves and did not need to be re-started after EDGs energized the safety buses ("dash" buses). However, inclusion of this information in the SPAR model would not change the dominant sequences and, therefore, would not affect the conclusion that the event is an ASP.

Response: No response is required.

Licensee's Comment 4.4: Because of the QCNPS electrical design, condensate pumps can be "backed" from the EDGs. Therefore, given failure of normal Emergency Core Cooling Systems (ECCS), and given the availability of instrument air and service water, the combination of condensate for injection and standby coolant supply for condenser makeup could be used for reactor makeup. Again, however, inclusion of this information in the SPAR model would not change the dominant sequences and, therefore, would not affect the conclusion that the event is an ASP.

Response: No response is required.

Licensee's Comment 4.5: While the CCDPS calculated by the SPAR model and by the EGC PRA are comparable, the sequences and cutsets dominating those CCDPs are significant different. Specific explanations and suggestions are provided in subsequent comments.

Response: No response is required.

Licensee's Comment 4.6: 44% of the SPAR model risk comes from Anticipated Transient Without Scram (ATWS). It is surprising that ATWS would be such a large fraction of LOOP risk, and more surprising that it would be the dominant source. It appears that the size of this contribution is not realistic, and it appears that the reason is a modeling decision to take no credit, for the LOOP initiator, for the ordinary Emergency Operating Procedure actions to respond to an ATWS. To accurately represent risk, the SPAR model should be improved to give that credit. Doing so would reduce the ATWS contribution to LOOP by between one and two orders of magnitude. The Exelon PRA does give that credit, and the top corresponding LOOP/ATWS cutset (LOOP frequency set to 1.0) has a probability of 3.8×10^{-8}.

Response: Exelon is correct in noting that the reason why failure of the reactor protection system (RPS) is such a large fraction of the SPAR model CCDP comes from the modeling assumption to take no credit for the transfer to ATWS event tree following a LOOP with subsequent failure of RPS.

The NRC is considering adding logic to the SPAR models to credit the transfer to the ATWS event tree at Quad Cities following a LOOP and failure of RPS. The NRC would like to make the SPAR models for Quad Cities more realistic with respect to this assumption. However, the SPAR model cannot be changed without documentation verifying the change is appropriate and technically correct. The NRC presently does not have such documentation.

The NRC appreciates your effort to improve the SPAR model for Quad Cities, but the model will remain as stated in the precursor report unless Quad Cities can provide the NRC with the appropriate documentation for changing the model. We would appreciate Quad Cities forwarding to the NRC documentation of the analysis (neutronic and thermal hydraulic) that permits Quad Cities to take credit for the transfer to ATWS event tree following a LOOP and failure of RPS. The NRC would also appreciate copies of the plant-specific emergency operating procedures that guide the Quad Cities operators through the event - LOOP followed by failure of RPS.

Licensee's Comment 4.7: ATWS probabilities for QCNPS are based on NUREG/CR-5500, volume III. The mechanical ATWS probability is 2.1×10^{-6} and the electrical is 3.7×10^{-6}. It is interesting to observe that the SPAR probabilities appear to be significantly smaller. The SPAR event RPS-SYS-FC-CRD, "Control rod drive mechanical failure," has a probability of 2.5×10^{-7}. The sum of two electrical SPAR events, RPS-SYS-FC-PSOVS, "HCU scram pilot SOVs fail," and RPS-SYS-FC-RELAY, "Trip system relays fail," is $(1.7 \times 10^{-6} + 3.8 \times 10^{-7}) = 2.1 \times 10^{-6}$. EGC requests that the NRC Staff please provide the bases for the SPAR ATWS probabilities.

Response: The basis for the SPAR ATWS probabilities is NUREG/CR-5500, Volume 3. This can be seen in a comparison of LOOP Sequence 65 in Table 3 of the SPAR analysis to Tables 5 and 6 on pages 23 and 24, respectively, of NUREG/CR-5500, Volume 3.

Minimal cut sets	SPAR CCDP Table 3	General Electric Unavailability with Credit for Manual Scram by Operator (NUREG/CR-5500, Volume 3, Table 5)	SPAR % of CCDP Table 3	Contribution from CCF Events with Credit for Manual Scram by Operator (NUREG/CR-5500, Volume 3, Table 6)
RPS-SYS-FC-PSOVS	1.7×10^{-6}	1.9×10^{-6}	69.7%	71%
Hydraulic control unit scram pilot SOVs fail in SPAR - HCU in NUREG/CR-5500				
RPS-SYS-FC-RELAY	3.8×10^{-7}	3.8×10^{-7}	15.6%	14%
Trip system relays fail in SPAR - Trip system in NUREG/CR-5500				
RPS-SYS-FC-CRD	2.5×10^{-7}	2.5×10^{-7}	10.2%	10%
Control rod drive mechanical failure in SPAR - Rod in NUREG/CR-5500				
Total	2.4×10^{-6}	2.6×10^{-6}		

<u>Licensee's Comment 4.8</u>: 17% of SPAR model risk comes from a sequence involving a stuck-open "SRV," failure to cool the containment or to cool the suppression pool, and failure to vent containment. Only one cutset dominates this sequence, and the failures beyond the stuck-open valve involve two operator actions, lining up RHR and venting containment. They are modeled as dependent operator actions (RHR-XHE-XM-ERROR, CVS-XHE-XE-VENT2), and the combination results in a combined operator failure of $(5 \times 10^{-4})(3.1 \times 10^{-2}) = 1.6 \times 10^{-5}$. A similar combination of failures in the EGC PRA is assigned a failure probability of 5×10^{-7}. The EGC QC HRA (Human Reliability Analysis) Notebook states that the actions to cool the suppression pool and to vent containment "have completely different symptoms and QGA instructions to initiate them. The time frames are completely different, and there likely will be different crews involved in making the decisions." Torus cooling is aligned in the first 30 minutes, while containment venting is not required until 20 hours into the event. As a result, it is concluded that there is a low dependence, and EGC assigns a "floor" value for combined operator actions of 5×10^{-7}. It appears that a smaller dependent operator action probability should be used in the SPAR model.
The NRC response is for both Licensee Comment 4.8 and 4.9

<u>Licensee's Comment 4.9</u>:16% of SPAR model risk comes from a sequence that is analogous to the above sequence, but involves successful "SRV" operation. Again, only one cutset represents this sequence. It involves the same dependent operator actions as above, but it also includes some credit for recovery of suppression pool cooling. With this credit, the overall combined operator action probability is reduced to 5×10^{-7}, which, by coincidence, is the same as the Exelon probability with no recovery of suppression pool cooling. This supports the comment in Paragraph 4.8.

Response: The value used in the SPAR analysis for CVS-XHE-XE-VENT2, as given in Table 4 of the report, is 5.1×10^{-2} not 3.1×10^{-2}. If this correction is made, the combination of operator errors in comment 4.8 is increased to $(5 \times 10^{-4})(5.1 \times 10^{-2}) = 2.6 \times 10^{-5}$. If this correction is made, the combinations of operator errors in comment 4.9 is increased to 8.1×10^{-7}. However, the Exelon observation is correct in that there is a difference in the treatment of operator actions for the case of LOOP with a stuck-open relief valve versus the LOOP without a stuck-open relief valve. Credit was given for operator recovery of RHR for LOOP with no stuck-open relief valve.

It is believed that a stuck-open relief valve will make the actions of the operators a little more complex and difficult following a LOOP. At the minimum, more mass and energy will be released from the reactor vessel to the suppression pool in a shorter time. Efforts to shut the stuck-open relief valve will also occupy some of the operators' attention and resources. In recognition of such factors, no credit was given for operator recovery of decay heat removal if human error were to fail the RHR system following a LOOP with stuck-open relief valve. This was considered a "conservative" assumption.

The NRC would like to make the SPAR models for Quad Cities more realistic with respect to this assumption. However, the SPAR model cannot be changed without documentation verifying that the change is appropriate and technically correct. The NRC presently does not have such documentation.

The NRC appreciates your effort to improve the SPAR model for Quad Cities, but the model will remain as stated in the precursor report until Quad Cities can provide the NRC with the appropriate documentation for changing the model. The NRC would appreciate Quad Cities forwarding to the NRC the plant-specific emergency operating procedures that guide the Quad Cities operators through the event - LOOP followed by stuck-open relief valve followed by failure of the RHR system. Hopefully, Quad Cities personnel would be able to add additional explanation to these operating procedures that would demonstrate that operators would perform the same actions, within the same approximate time frame, for both LOOP without a stuck-open relief valve and failure of the RHR system and LOOP with a stuck-open relief valve and failure of the RHR system.

Licensee's Comment 4.10: 13% of SPAR model risk comes from a sequence with failure of all high-pressure injection and failure of manual reactor depressurization. The top two cutsets from this sequence involve loss of DC power on both divisions. The next two comments deal with this sequence.

Response: No response is required.

Licensee's Comment 4.11: The first of these cutsets consists of the LOOP initiator and common cause failure of both batteries. Note that this cutset has nothing to do, specifically, with a LOOP. This failure can happen for any initiator, including ordinary turbine trip, and many initiators are far more likely than a LOOP. In fact, the EGC QCNPS PRA models a loss-of-both-DC-buses initiating event. EGC recognized that, since both DC buses are normally energized, losing both of them at once is likely to be an initiator rather than a dependent failure. Consequently, for EGC, combinations of LOOP and common-cause failure of both DC trains are covered by the loss-of-both-DC-buses initiating event and they are not counted separately for loss of offsite power. If the SPAR model has such an initiator, consider removing these kinds of cutsets from the LOOP logic.

Response: The Quad Cities SPAR model does not have an initiator for dual failure of both dc buses. However, the Quad Cities SPAR model includes a loss-of-dc bus (single) initiator with a initiating event frequency of 2.4×10^{-7}/hour. In addition, the SPAR models do include the failure of one or both buses (either by independent failure or common-cause failure) for other initiating events. The probability of both dc buses failing is very small but cannot be discounted. For an actual LOOP, the failure of both of the dc batteries following the LOOP must be calculated as leading to a reactor core damage event.

Licensee's Comment 4.12: The second of these cutsets appears to be invalid. It involves the initiator, bus failure for Division I DC, and failure of the operator to align the standby charger for Division II. The logic appears to fail to give credit for the normal supply to Division II DC. This appears to be a logic error.

Response: The SPAR model cut set addressed by this comment is due to incomplete modeling of the dc power system. The current Quad Cities SPAR model does not include alternate dc power supplies to the emergency diesel generators. These alternate dc power supplies will be added to the next revision of the Quad Cities SPAR model, thus eliminating this cut set and similar related cut sets. Inclusion of this change in the SPAR model would not significantly change the dominant

sequences and, therefore, would not affect the conclusion that the event is an accident sequence precursor.

Licensee's Comment 4.13: The SPAR model should probably be revised to recognize dependency of more combinations of independent operator actions. Response to LOOP requires quite a few actions by operators. Of the top nine EGC PRA cutsets, eight of them involve various combinations of failure of two or more potentially dependent operator actions. Those cutsets represent a CCDP of 2.8×10^{-6}. It appears that the reason that the EGC model yields a CCDP as large as the SPAR model, after consideration of the comments above, is because it includes many combinations of dependent operator actions not included in the SPAR model. Consider searching for, and then modeling, more such dependencies in the SPAR cutsets.

Response: The SPAR model with respect to dependency of multiple operator action is undergoing review and possible revision.