Carolina Power & Light Company
P.O. Box 10429
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April 3, 2000

10 CFR 50.73

SERIAL: BSEP 00-0039

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324
LICENSE NOS. DPR-71 AND DPR-62
LICENSEE EVENT REPORT 1-00-001

Gentlemen:

In accordance with the Code of Federal Regulations, Title 10, Part 50.73, Carolina Power & Light Company submits the enclosed Licensee Event Report. This report fulfills the requirement for a written report within thirty (30) days of a reportable occurrence.

Please refer any questions regarding this submittal to Mr. Warren J. Dorman, Manager - Regulatory Affairs, at (910) 457-2068.

Sincerely,

FOR

C. J. Gannon
Plant General Manager
Brunswick Steam Electric Plant

CRE/cre

Enclosure: Licensee Event Report

IE22

cc (with enclosure):

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NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION
(6-1998)

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001

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FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant (BSEP), Unit No. 1	05000 325	1 OF 10

TITLE (4)
Loss of Offsite Power During Refuel Outage

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									BSEP Unit No. 2	05000 324
03	03	2000	2000	-- 001 --	00	04	03	2000	FACILITY NAME	DOCKET NUMBER
										05000

OPERATING MODE (9)	5
POWER LEVEL (10)	000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR : (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)	X	50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)	X	50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Charles R. Elberfeld, Senior Analyst - Regulatory Affairs	(910) 457-2136

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
X	EK	XFMR	General Electric Company	Y					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On March 3, 2000, at 0931 hours, with Unit 1 in a refuel outage and Unit 2 at 100 percent rated thermal power, a switch positioning error, made during switchyard relay trip test activities, resulted in a loss of offsite power (LOOP) for Unit 1, and initiation of numerous Engineered Safety Feature (ESF) actuations including a shutdown cooling isolation. At approximately 1200 hours, the failure of emergency Diesel Generator 2 (DG2) excitation system power potential transformer (PPT) resulted in a loss of power to emergency bus E2, which caused a Technical Specification Limiting Condition for Operation 3.0.3 entry for Unit 2, another initiation of numerous ESF actuations on Unit 1, and the actuation of the halon system in the Diesel Generator Building, which caused an actuation of the Control Room Emergency Ventilation system in the chlorine protection mode.

The root cause of the LOOP event is personnel error; inadequate self-checking and attention to detail on the part of the transmission maintenance technicians performing and verifying the relay trip testing in the switchyard relay house. The root cause of the PPT failure is a short between turns of the secondary winding.

The switch positioning error was corrected and offsite power restored to the site on March 3, 2000, at 1147 hours. The DG2 excitation system PPT was replaced and DG2 declared operable on March 8, 2000. This event is being reported in accordance with 10 CFR 50.73(a)(2)(i)(B), 10 CFR 50.73(a)(2)(iv), and 10 CFR 50.73(a)(2)(v)(D).

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

INTRODUCTION

On March 3, 2000, at 0931 hours, a switch positioning error, made during switchyard relay trip test activities, resulted in a loss of offsite power (LOOP) for Unit 1, initiation of numerous Primary Containment Isolation system [JM] (PCIS) signals accompanied by valve movement, actuation of the Standby Gas Treatment (SBGT) system [BH], isolation of the Reactor Building Heating Ventilating and Air Conditioning (HVAC) system [VA], and short term loss of shutdown cooling. At approximately 1200 hours, the failure of an emergency diesel generator [EK] excitation system power potential transformer [XFMR] (PPT), Manufacturer: General Electric, Model Number: 9T28Y1323 G 10, resulted in a loss of power to emergency bus [EB] E2. This caused a Technical Specification (TS) Limiting Condition for Operation (LCO) 3.0.3 entry for Unit 2, another initiation of PCIS signals accompanied by valve movement for Unit 1, actuation of the SBGT system, isolation of the Reactor Building HVAC system, short term loss of shutdown cooling, and the actuation of the halon system [KQ] in the Diesel Generator Building [NB], which caused an actuation of the Control Room Emergency Ventilation (CREV) system [VI], in the chlorine protection mode.

Notifications associated with this event were made to the NRC in accordance with 10 CFR 50.72(a)(1)(i); 10 CFR 50.72(b)(1)(i)(A); and 10 CFR 50.72(b)(2)(ii), (iii), and (vi). Reference Event Numbers: 36750, 36751, and 36752. This event is being reported in accordance with 10 CFR 50.73(a)(2)(i)(B), as operation or condition prohibited by the plant's TS (i.e., Unit 2 TS LCO 3.0.3 entry); 10 CFR 50.73(a)(2)(iv), as an event that resulted in an automatic actuation of any engineered safety features (i.e., Unit 1 SGBT system, PCIS, Reactor Building HVAC, and CREV system isolation/actuations); and 10 CFR 50.73(a)(2)(v)(D) as an event or condition that alone could have prevented the fulfillment of the safety function of structures or systems required to mitigate the consequences of an accident (i.e., Unit 1 LOOP).

INITIAL CONDITIONS

At the start of the event, Unit 1 was in Mode 5, day six of a refuel outage, with the reactor cavity flooded and temperature being controlled in a temperature band of 80 to 100 degrees Fahrenheit (F). Core alterations were in progress. The Residual Heat Removal (RHR) system [BO] Loop A and the Unit Auxiliary Transformer [XFMR] (UAT) were out of service for maintenance. Unit 2 was in Mode 1 at 100 percent of rated thermal power. Unit 2 was also in LCO 3.8.1 Condition A, which is a 45-day LCO for the Unit 1 UAT being out of service.

EVENT DESCRIPTION

On March 3, 2000, at 0846 hours, relay trip testing in the switchyard relay house by utility transmission maintenance technicians was authorized by the Unit 1 control room senior reactor operator. At 0931 hours, a

switch positioning error, made during the relay trip test activities, resulted in a trip of the Unit 1 balance-of-plant (BOP) buses which feed electrical power to the 4160 VAC emergency buses E1 and E2. This resulted in the automatic starting of all four emergency diesel generators (i.e., DG1, DG2, DG3, and DG4). DG1 and DG2 automatically energized buses E1 and E2 as designed; the 4160 VAC emergency buses E3 and E4 did not lose power so DG3 and DG4 did not automatically energize their respective buses. The loss of power to buses E1 and E2 resulted in the following automatic actuations on Unit 1:

- PCIS Valve Group 1, Main Steam Line Drain isolation valve,
- PCIS Valve Group 2, Drywell Floor Drain isolation valves,
- PCIS Valve Group 6, Containment Atmosphere isolation valves,
- PCIS Valve Group 8, RHR Shutdown Cooling isolation valves, resulting in a loss of shutdown cooling,
- PCIS Valve Group 10, Non-interruptible Air to Drywell isolation valves,
- Reactor Building HVAC isolation,
- Both trains of the SBGT system, and
- Reactor Protection system [JC] (RPS); however, all control rods were already fully inserted into the core.

Additionally, for Unit 1, the Fuel Pool Cooling (FPC) and Supplemental Spent Fuel Pool Cooling (SSFPC) systems [DA] became unavailable due to the loss of electrical power. A fuel bundle was being moved when the LOOP occurred. The bundle was placed in a safe position when electrical power was restored to the fuel handling equipment. Core Alterations and handling of irradiated fuel in secondary containment were suspended. No operations with the potential to drain the reactor vessel were in progress. Plant operators entered the appropriate LCOs and procedures for the plant conditions and directed the transmission maintenance technicians to suspend the relay testing activities. The operators and transmission maintenance technicians backed out of the test by restoring the subject equipment to the pre-test alignment. During the realignment, a test switch position error in the relay house was identified and the information was immediately communicated to the control room.

For Unit 2, no other automatic actuations other than the starting of DG3 and DG4 occurred. Other effects of the LOOP on Unit 2 included the following:

- Bypass of the Augmented Off-Gas system,
- Trip of the Hydrogen Water Chemistry system,
- Trip of a Turbine Building chiller,
- Trip of a Conventional Service Water pump, and
- Trip of a Drywell cooler.

These effects were expected, in accordance with plant design; Unit 2 operators responded appropriately to the effects, as plant conditions warranted. At approximately 0942 hours, the Unit 2 Service Air system was cross-tied to the Unit 1 to maintain the Unit 1 Instrument Air header pressurized.

The following event recovery actions were taken for Unit 1:

- At 0950 hours, an Unusual Event (UE) was declared due to the inability to power either bus E1 or E2 from off-site power sources.
- At 0952 hours, shutdown cooling was restored.
- At 0956 hours, the RPS trip actuation logic was reset.
- At 1007 hours, restoration of the SSFPC system was completed.
- At 1025 hours, the Reactor Building HVAC system was restarted.
- At 1031 hours, both trains of the SBGT system were placed in the "standby" mode of operation.

Shortly following the LOOP, a review team was established to determine the cause. Prior to the team assembling, the transmission maintenance technicians had reported to the control room that during the realignment of the relay test switches, they had identified a mis-positioned switch which could account for the LOOP. Once the review team evaluation verified that the mis-positioned switch was the cause of the LOOP, preparations were made to realign the BOP and emergency buses to offsite power sources. By 1147 hours, the Unit 1 BOP buses were re-energized from offsite power.

At 1154 hours, the control room received an annunciator indicating a ground over-current condition on DG2. Priorities were set to synchronize and transfer bus E2 to an offsite power source so that DG2 could be secured. Within the next two minutes, multiple annunciators were received indicating fire detection and halon system actuation in the Diesel Generator Building. At approximately 1156 hours, the plant fire alarm was sounded and the plant entered Prefire Plan Procedure 0PFP-013, "General Fire Plan." Prevailing winds were from the Diesel Generator Building to the Control Building, and at approximately 1158 hours, the CREV system actuated in the chlorine protection mode due to halon being detected at the CREV intake. Two attempts to parallel bus E2 with offsite power were unsuccessful with the master/slave breakers tripping open.

At approximately 1200 hours, DG2 tripped and bus E2 became de-energized resulting in the following automatic actuations on Unit 1:

- PCIS isolations, including Valve Group 8, which resulted in the loss of shutdown cooling,
- Reactor Building HVAC isolation, and
- Both trains of the SBGT system.

Additionally, the SSFPC system tripped. Plant operators entered the appropriate LCOs for the plant conditions. It could not be initially determined whether the electrical fault was on bus E2 or on DG2. As such, no further attempts were made to energize bus E2 with offsite power. The fire brigade mustered near the Diesel Generator Building and teams were established to conduct primary searches of the building. Results from the search teams indicated that no fire was present. The halon initiation resulted in the Diesel Generator

Building ventilation system isolating, so the fire brigade proceeded to ventilate the building to remove the halon and restore a normal atmosphere. Access to the Diesel Generator Building was restricted due to the halon discharge causing the atmosphere inside the building to be unsafe for breathing (i.e., low oxygen concentration).

The following event recovery actions were taken:

- At 1218 hours, shutdown cooling was restored on Unit 1.
- The SSFPC system was returned to service on Unit 1 at 1248 hours.
- At 1300 hours, Unit 2 entered TS LCO 3.0.3 due to the loss of two offsite AC power sources to Unit 1 concurrent with DG2 being inoperable.
- By 1311 hours, DG3 and DG4 were secured.
- At 1357 hours, Unit 2 operators began a reactor shutdown in accordance with TS LCO 3.0.3.
- The Site Emergency Coordinator directed that the emergency response facilities be activated to assist with the restoration of power and assessment of damage to the DG2 electrical system.
- By 1410 hours, the Emergency Operations Facility, Technical Support Center, and Operations Support Center were activated.
- At approximately 1500 hours, the Diesel Generator Building ventilation was restored and oxygen concentration measurements were being conducted routinely.
- At 1521 hours, the Unit 2 service air crosstie to Unit 1 was closed.
- By 1613 hours, oxygen concentration in the Diesel Generator Building basement was restored to normal and access was restored to the area.
- At 1647 hours, the alarm indicating high chlorine presence at the control building ventilation intake cleared, and the CREV system was returned to the "standby" mode of operation.
- Following identification and inspection of DG2 excitation transformer [XFMR] damage, at 1731 hours, engineering personnel notified the Unit 1 Control Room that there was no fault on bus E2 and that it could be powered from offsite sources.
- At 1756 hours, bus E2 was re-energized from offsite power, and Unit 2, which was operating at approximately 57 percent of rated thermal power, exited TS LCO 3.0.3, but remained in TS LCO 3.8.1 Condition F due to DG2 inoperability concurrent with the Unit 1 UAT being out of service.
- Bus E1 was transferred from DG1 to offsite power at 1805 hours.
- At 1814 hours, the cooling water was restored for the FPC system.
- At 1815 hours, DG1 was shut down and later returned to standby.
- At 1840 hours, the UE was terminated and the emergency response facilities were de-activated.
- By 2146 hours, the Reactor Building HVAC system was restarted and both SBGT system trains were placed in standby.

On March 4, 2000, at 0000 hours, due to concurrent inoperability of DG2 and the Unit 1 offsite power source from the UAT in excess of 12 hours, Unit 2 entered TS LCO 3.8.1 Condition H, which requires the unit to be in hot shutdown within 12 hours. Efforts were already underway to return the Unit 1 UAT backfeed to service, and at 0407 hours, the UAT backfeed was returned to service. Unit 2 exited LCO 3.8.1 Condition H at that time. Unit 2 remained in TS LCO 3.8.1 Condition D, Required Action D.4 to restore DG2 to operable status within seven days, until DG2 was restored to operable status on March 8, 2000, at 1208 hours.

EVENT CAUSE

LOOP Event

The root cause of the LOOP event is attributed to personnel error; inadequate self-checking and attention to detail on the part of the utility transmission maintenance technicians performing and verifying the relay trip testing in the switchyard relay house. While performing the isolation section of the procedure, which would have prevented the trip of the BOP buses, the first technician located the correct device label specified in the procedure (i.e., BUS DIFF L/O-86P2/1A TEST SWITCH), which is the label identifying a bank of ten test switches labeled A through J. The procedure called for manipulating switch "E" on the device. Although the technician identified the proper device label, he associated the wrong device with the label and manipulated the "E" switch on the device directly above the label (i.e., BUS DIFF L/O-86P/1A TEST SWITCH). A second technician, who was mentoring the first and reading the procedural steps aloud, was positioned such that the specific device label could not be read. Following completion of the isolation section of the procedure, a third technician performed an independent verification of the switch manipulations before proceeding with the test. Although the procedure did not require an independent verification of the steps, as a general rule, independent verification is used for manipulations deemed critical. The independent verifier made the same association error as the first technician. By failing to position the correct switch, the equipment logic was set so that the 86P2-1A device would trip the BOP bus feeder breakers to isolate the simulated fault when the test continued.

The equipment being tested is maintained by the Transmission department, but maintenance activities can have a direct impact on the equipment operated and maintained by the Nuclear Generation Group (NGG) of Carolina Power & Light (CP&L) Company. A review of this event revealed that improvements could be made in several areas associated with human performance standards and expectations in the Transmission department. Areas highlighted by the review include:

- Work practices, failure to follow through on post task activities,
- Verbal Communication, pre-job briefing not performed for all members of the crew,
- Program/Organization Deficiency, personnel had not received specific training on Stop, Think, Act, Review (STAR) and Self-Checking, and
- Work practices, procedure use and compliance.

DG2 Trip Event

The cause of the DG2 Trip event is attributed to the faulted phase C of the DG2 excitation system PPT. The fault on the PPT phase C to ground during the period that operators were trying to return bus E2 to an offsite power source resulted in the phase C line to ground voltage dropping below the breaker protective function setpoint, opening the breaker to protect bus E2 and its sources. Further degradation of the fault resulted in the DG2 trip on differential overcurrent approximately two to three minutes after the attempts to return bus E2 to an offsite power source.

The PPT phase C transformer was dismantled and examined. It appeared that the transformer failed due to shorted turns on the secondary winding which caused overheating due to high circulating currents and resulted in the melting of the aluminum conductors on the secondary winding. The molten aluminum ran down the secondary winding and out to the grounded transformer frame. The degradation of the secondary and primary windings continued until the differential/overcurrent setpoint was reached and DG2 tripped.

The root cause of the transformer failure is a short between turns of the secondary winding. Due to the damage that occurred during the failure, a more specific failure mechanism cannot be identified. Potential failure mechanisms considered were transformer age, primary winding encapsulation cracking, cleanliness, improperly installed secondary winding blocking, and secondary winding insulation breakdown. Based on inspection, engineering judgement, and consultation with industry experts, the potential failure mechanisms were eliminated with the exception of secondary winding insulation breakdown.

CORRECTIVE ACTIONS

LOOP Event

A stand down was conducted, with the transmission maintenance crew involved with the switchyard relay testing, to review the LOOP event and to emphasize the importance of and techniques related to human performance. No additional testing was performed. The Transmission department has developed a comprehensive human performance action plan which was approved on March 16, 2000. This plan addresses the issues of human performance standards and expectations within the Transmission department as the issues apply to interface with the NGG within CP&L. Details of the plan include:

- Implement human performance training/requirements for personnel performing critical activities at transmission facilities,
- Provide independent verification training/requirements for personnel performing critical activities at transmission facilities,

- Implement human performance/human factors standards into applicable transmission department procedures, processes, and practices,
- Implement a practice and procedure review to identify best practices and areas for improvement and implement system-wide changes based on findings of the review,
- Evaluate knowledge/training needs of technicians and provide training in identified areas,
- Review the March 3, 2000, LOOP event with applicable maintenance and construction personnel,
- Review switchyard equipment labeling practices in regard to human performance aspects and re-label equipment as appropriate,
- Provide training to personnel performing critical work affecting nuclear generating facilities on an overview of the offsite power system and how the LOOP will affect the facility,
- Enhance coordination with generating facilities in evaluating risk of outage related transmission department activities, and
- Implement senior management visits to transmission crews at nuclear generating facilities to review the March 3, 2000, LOOP event.

The action plan is scheduled to be completed before February 5, 2001, with periodic updates to be provided to the BSEP staff.

Action to evaluate industry operating experience and benchmark other facilities to identify best practices for switchyard/transformer yard work will be completed by June 15, 2000. Appropriate actions to implement the identified best practices will follow.

As part of the event review, additional opportunities to improve and share experience were identified in the areas of control of switchyard activities, procedural enhancements, outage risk assessment and work planning of switchyard activities, and event review for licensed and non-licensed operators. Actions are in progress to address these identified issues.

DG2 Trip Event

The DG2 excitation system PPT was replaced. Additionally, a diode rectifier, identified as weak, was replaced and DG2 was declared operable, after successful re-testing, on March 8, 2000. The associated excitation system PPTs for DG1 and DG3 have been examined utilizing thermography and DG4 is scheduled to be examined on April 9, 2000 to provide assurance of continued reliability. By November 24, 2000, the DG1, DG3, and DG4 excitation system PPTs will be tested and/or replaced during future planned diesel generator outages. This will provide further assurance of future equipment performance and will potentially provide a better understanding of the failure mechanism that affected the DG2 excitation system PPT.

SAFETY ASSESSMENT

The safety significance of this event was minimal. With the exception of the DG2 equipment failure, required equipment responded as designed to the event. The following discussion addresses the impact of losing offsite power and bus E2 on Unit 1 and Unit 2.

Unit 1

Unit 1 was in a refueling outage, which was planned and conducted using a defense in depth philosophy. As such, sufficient equipment was maintained operable to ensure adequate protection of key safety parameters. During this event, the refuel pool was flooded; as such, a large water inventory was available. No activities which had the potential to drain the vessel were in progress. Therefore, the probability of a major inventory loss at this time was low. During the entire event, multiple injection sources for inventory makeup were available. At a minimum, these sources included RHR pump B, Control Rod Drive (CRD) pump A, and the Category I makeup source (i.e., Nuclear Service Water system to the fuel pool). Core spray (CS) pump A was capable of being restored to service within one hour.

Decay heat removal requirements, in both the vessel and the spent fuel pool, were relatively low. The maximum localized heat-up rate in the vessel was approximately 14.6 degrees F per hour, which equates to a time to boil in excess of eight hours. Shutdown cooling was restored in 21 minutes for the first loss and 18 minutes for the second loss.

At the time of the event, approximately half of the spent fuel had been transferred to the spent fuel pool. The spent fuel pool localized heat-up rate was approximately 6 degrees F per hour, which equates to a time to boil of approximately 24 hours. Spent fuel pool cooling was restored, using the SSFPC system, in 36 minutes for the first loss and 48 minutes for the second loss.

As a result of (1) the large inventory of water present with the refuel pool flooded, (2) the multiple makeup sources available, (3) the relatively long time to boil in both the vessel and the spent fuel pool, and (4) the short duration of the losses of shutdown cooling and spent fuel pool cooling, the safety significance of the event for Unit 1 was minimal.

Unit 2

Unit 2 was operating at full power with no significant online maintenance activities in progress at the time of this event. Due to the shared electrical distribution system loads, some Unit 2 loads are supplied by bus E2. The Low Pressure Coolant Injection (LPCI) mode of the RHR system uses two identical pump loops, each loop with two pumps in parallel (i.e., LPCI subsystem 2A consists of RHR pumps 2A and 2C, subsystem 2B consists of pumps 2B and 2D). The power for each unit RHR pump is supplied by a separate bus (i.e., bus E2 supplies RHR pump 2D). The two loops are arranged to discharge water into different reactor recirculation

loops. A cross-connection exists between the pump discharge lines of each RHR loop. Power for the injection valves associated with each RHR loop is supplied by separate buses (i.e., bus E2 supplies the 2B injection valves, the same subsystem which contains the 2D RHR pump). As such, the most significant impact of loss of bus E2 on Unit 2 is the inability to inject with the 2B RHR loop. This condition is bounded by existing accident analysis that considers a Loss of Coolant Accident coincident with a LOOP on one unit and a safe shutdown of the other unit concurrent with the worst-case single failure (i.e., loss of one Diesel Generator). Therefore, the safety significance of the event for Unit 2 was minimal.

PREVIOUS SIMILAR EVENTS

A review of events for the past three years has not identified any similar events of LOOP due to switchyard maintenance activities or Diesel Generator electrical failures resulting in a de-energized emergency bus.

COMMITMENTS

Those actions committed to by CP&L in this document are identified below. Any other actions discussed in this submittal represent intended or planned actions by CP&L. They are described for the NRC's information and are not regulatory commitments. Please notify the Manager - Regulatory Affairs at BSEP of any questions regarding this document or any associated regulatory commitments.

1. The Transmission Department Human Performance Action Plan associated with BSEP will be completed before February 5, 2001.

2. Action to evaluate industry operating experience and benchmark other facilities to identify best practices for switchyard/transformer yard work will be completed by June 15, 2000. Appropriate actions to implement the identified best practices will follow.

3. By November 24, 2000, the DG1, DG3, and DG4 excitation system PPTs will be tested and/or replaced during future planned diesel generator outages.