NRC Form 366 (4-95)

U.S. NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER)

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

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PILGRIM NUCLEAR POWER STATION	05000-293	1 of 17

TITLE (4)
Loss of Preferred Off-Site Power and Oil Spill Due to Main Transformer Fault While Shut Down

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 N/A	DOCKET NUMBER 05000
03	07	97	97	004	00	04	07	97	FACILITY NAME N/A	DOCKET NUMBER 05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (Check one or more) (11)							
POWER LEVEL (10)	00		20.2201 (b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
			22.2203(a)(1)		20.2203(a)(3)(i)	x	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)		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)
Douglas W. Ellis - Principal Engineer	(508) 830-8160

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	EA	XFMR	W 120	Y						

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE(15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)		NO		06	30	97

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

On March 7, 1997, at 1449 hours, an automatic start of the 'B' train emergency diesel generator and an actuation of the secondary containment isolation control system and a portion of the primary containment isolation control system occurred while shut down during the 1997 refueling outage. The event was the result of an electrical fault in the main transformer that was energizing the unit auxiliary transformer and related 4.16 Kv electrical power distribution system at the time of the event. The fault also resulted in a significant leak of main transformer insulating oil into the area of the transformer and adjacent turbine building. The diesel generator loaded onto its bus, and the containment isolation systems actuated as designed for the conditions existing at the time of the event.

The root cause of the main transformer fault had not been finalized when this report was prepared. This report will be supplemented after the root cause analysis is completed. Corrective action planned includes updating the fire hazards analysis report, replacement of the main transformer, and installation of a berm(s) in the oil spill area. Other action being taken or planned includes the replacement of some degraded cable identified during the ongoing root cause analysis, and evaluating modifications or compensatory measures for the station blackout diesel generator.

The event occurred with the reactor mode selector switch in the REFUEL position. The reactor vessel was completely de-fueled, and no reactor fuel movement was in progress. The event posed no threat to public health and safety.

BACKGROUND

The 1997 refueling outage began on February 15, 1997. As part of preparation and planning for the refueling outage, temporary procedure TP 96-049, "RFO 11 Compensatory Measures," was prepared and approved prior to the refueling outage. In summary, the procedure provides operations personnel with an overview of the RFO-11 schedule and identifies vulnerability to loss of off-site power and decay heat removal capability, compensatory measures (event based), and available compensatory systems (symptom based). Moreover, the procedure includes attachments that include loss off-site power safeguards, contingency for a loss of shutdown cooling, temporary power feeding plant equipment, and outage safety review.

Conditions existing at the time of the event were as follows.

- The reactor vessel was completely de-fueled, and no fuel movement was in progress. The gates were installed between the reactor vessel and the spent fuel pool.

- The residual heat removal (RHR) system train 'B' was in the augmented fuel pool cooling (AFPC) mode of operation. The spent fuel pool temperature was approximately 86 degrees Fahrenheit.

- The preferred off-site 345 Kv power sources, transmission lines 342 and 355, were energized. The 345 Kv switchyard ring bus circuit breakers ACBs 102, 103, 104, and 105 were closed. The startup transformer (SUT) was tagged out of service for maintenance and the mechanical disconnects from ACB-102 and ACB-103 to the SUT were open. Portions of the station's 4.16 Kv auxiliary power distribution system were being powered from the unit auxiliary transformer (UAT) that was energized by the 345 Kv switchyard via ACBs 104 and 105 and the main transformer. Located at the end of this report is a simplified single line diagram of the 345 Kv switchyard, SUT, and UAT.

The main transformer normally converts, or steps-up, main generator 23 Kv output power to 345 Kv power. In the configuration for this event, the main transformer was functioning as a step-down transformer with the isophase bus bars mechanically disconnected from the main generator. The isophase bus bars connect the main generator to the low voltage (primary) windings of the main transformer. The bus bars were mechanically disconnected for purposes of increased availability of preferred off-site power and shut down safety. When the main transformer is being used as a step-down transformer, the 4.16 Kv station auxiliary power distribution system can be powered from the 345 Kv switchyard via the main transformer and unit auxiliary transformer (UAT).

- The nonsafety-related 4.16 Kv Buses A1, A2, A3, and A4 and related electrical systems were in various configurations. Electrical loads from Buses A1 and A2 were de-energized. Bus A3 was energized and powering portions of its related electrical system. Bus A4 was energized and powering portions of its related electrical system including the station blackout diesel generator auxiliaries via 480 volt load center B7 and MCC-B40.

- Safety-related Bus A5 and portions of the related electrical system were energized by the UAT. The related emergency diesel generator (EDG 'A') was tagged out of service for maintenance.

- Safety-related Bus A6 and the related electrical system were energized by the UAT. The related EDG ('B') was in standby service. The safety-related 480 volt swing Bus B6 was energized by 480 volt load center Bus B2 that is powered from Bus A6.

- The secondary source of off-site power, the 23 Kv distribution system, was energized. The shutdown transformer (SDT), the station blackout diesel generator, and the related bus (A8) were in standby service.

- Work activities in the suppression pool were in progress for the replacement of the suction strainers for the residual heat removal and core spray systems pumps.

EVENT DESCRIPTION

On March 7, 1997, at 1449 hours, a loss of the preferred source of off-site power (345 Kv) occurred. The loss of power resulted from the automatic opening of ACB-104 and ACB-105 that were closed and providing off-site 345 Kv power to the main transformer and from it, the UAT and 4.16 Kv auxiliary power distribution system. The loss of the source of preferred off-site 345 Kv power resulted in the following:

- The loss of the source of power to nonsafety-related Buses A1, A2, A3, A4, and safety-related Buses A5 and A6, and related electrical systems that were powered by or from these buses at the time of the event.

- Safety-related Bus A5 and applicable portions of the respective load centers and motor control centers were re-energized automatically as designed by Bus A8 that was automatically energized from the SDT and 23 Kv distribution system. EDG 'A' did not start or load onto Bus A5 because it was tagged out of service for maintenance. The SDT is the first backup source of power for Bus A5 and A6 if either or both buses become de-energized and the bus is not re-energized by the respective EDG.

- Automatic start and loading of EDG 'B' onto Bus A6. Safety-related Bus A6 and its respective load centers and motor control centers were re-energized automatically by EDG 'B'. Safety-related Bus B6 was re-energized automatically by load center Bus B2.

- Automatic actuation of the reactor protection system (RPS) due to the de-energizing of the coils of the normally energized RPS relays. At the time of the event, the reactor vessel was completely de-fueled and the control rods that were installed at the time of the event either remained in the inserted position, inserted automatically, or remained in the withdrawn position because those control rods were tagged out of service.

- Automatic actuation of the primary containment isolation control system (PCIS). The actuation resulted in the automatic closing of primary containment Group 2 isolation valves (sampling) that were open.

- Automatic actuation of the reactor building isolation control system (RBIS) . The RBIS actuation resulted in the automatic start of the standby gas treatment system (SGTS) trains 'A' and 'B' and automatic closing of the reactor building ventilation system supply and exhaust dampers.

Numerous main control room alarms annunciated and related effects occurred due to the loss of the source of preferred off-site 345 Kv power. The alarms included panel C3L alarm C8, "Main XFMR Trouble." The effects included a loss of illumination from the normal lighting in the main control room; the emergency lighting system functioned to automatically illuminate the control room and other applicable station areas.

Utility licensed operator response included the following. Procedures 2.1.6, Reactor Scram," 2.4.16, "Distribution Alignment Electrical System Malfunctions," 2.4.25, "Loss of Shutdown Cooling," and 5.3.31, "Station Blackout," were entered in accordance with alarm response procedures and operator training. Procedure 5.3.31 was entered because the loss of normal station lighting in the control room and illumination by emergency lighting is a symptom for entering the procedure. Procedure 5.3.31 was exited because Buses A5 and A6 were energized and Bus A8 was energized from the 23 Kv distribution system via the SDT. Senior operations management arrived to oversee shift crew actions and assist the shift senior licensed operator (NWE) by coordinating communications with other station personnel. Senior operations management remained in this role until the SUT was powered by the preferred off-site 345 Kv power source.

The control room was notified of an oil spill by the main transformer and a licensed operator was dispatched for investigation. An operator was also dispatched to the EDG 'B' to monitor its operation and the operator subsequently reported EDG 'B' was operating satisfactorily.

Meanwhile, control room operators were briefed on procedure 2.2.85.2, "Augmented Fuel Pool Cooling (Without Shutdown Cooling) Mode 2." This action was taken in preparation of restoring fuel pool cooling (AFPC mode II) because spent fuel pool cooling was temporarily interrupted due to the brief loss of electrical power to the RHR system train 'B' (AFPC mode II) pumps that are powered from Bus A6 and its related electrical system.

By 1505 hours, the operator investigating the main transformer oil spill reported oil spilling inside the turbine building area (23' elevation) in the area near and entering the 4.16 Kv switchgear room 'B' (23' elevation). No fire or other evidence of oil ignition was observed. The senior shift licensed operator (NWE) was notified and station services personnel were directed to initiate procedures 1.3.22, " Oil Spill Prevention Control and Countermeasure Plan," and 5.5.4, "Response to Hazardous Material Incidents," and notify the Boston Edison Company (BECo) dispatcher for oil spill required notifications.

The nonsafety-related diesel driven air compressor was put into service at 1510 hours. This action was taken in accordance with procedure 2.4.16.

At 1518 hours, an announcement to clear the turbine building and main transformer areas and to prohibit on-site smoking was made to personnel over the plant paging system. This precautionary announcement was made for personnel safety due to potential fire concerns. The control room was notified by the mechanical and electrical maintenance manager at 1519 hours that the main transformer had experienced an electrical fault and no fire or explosion had occurred.

Meanwhile, insulating oil leaking from the main transformer was continuing to enter the area of the turbine building adjacent to the transformer. The oil was entering this area via the horizontal isophase bus ducts (33' elevation), primarily the phase 'A' bus duct and some through the phase 'B' duct. Each of the three isophase bus ducts are constructed of cylindrical, welded aluminum sections that are about three feet in diameter and extend horizontally from the main transformer through the adjacent turbine building south wall and into an adjacent, semi-enclosed area located in the turbine building. From the inner side of the turbine building wall, the ducts extend horizontally for a distance of about 20 feet, then descend vertically for about 5 feet, and then continue horizontally for a distance of about 30 feet where the ducts terminate in the area beneath the main generator casing. About 3 - 4 feet from the 5 foot vertical section, in the section toward the main generator, the bus ducts are separately joined to the isophase bus air cooling system cooler by three welded tee-type connections, one per isophase bus duct. The connections are the same size and construction as the isophase bus ducts. The oil was transported from the main transformer via the phase 'A' and phase 'B' bus ducts to the isophase bus cooling unit located on the turbine building floor (23' elevation). Most of the oil transported to the cooling unit flowed from the cooling unit and onto the floor. On the floor, the oil emanated outwardly and entered a floor drain in the immediate area, westerly to a wall and nearby stairwell, northerly to a wall in the area containing main generator auxiliary equipment and into the adjacent floor drain, northeasterly into the 4.16 Kv switchgear room 'B', and easterly to the turbine building trucklock area.

- In the area of the oil spill (23' elevation), the operator witnessed oil spreading to the western, northern, and eastern walls of the room containing the main generator hydrogen seal oil unit, stator cooling water unit and nearby floor drain, main generator hydrogen gas piping, main generator metering and relaying instrumentation, isophase bus ducts air cooling unit, main condenser scavenging system pumps and vacuum tank, fire protection system/main transformer deluge header and valves, and fire protection system/main generator carbon dioxide tank. The equipment was not in operation, and the operator's assessment was that there was no danger of a fire. The gross affected surface area was approximately 2,200 square feet, and the depth of oil in certain places in this area was reported to be greater than one inch. Oil containment efforts were ongoing or being effected at that time.

- The oil spread into the 4.16 Kv switchgear room 'B' that powers nonsafety-related equipment including main tranformer and generator exciter auxiliaries, Buses A2 and A4, and safety-related train 'B' equipment (including Bus A6). The room is separated from the immediate area of the oil spill by a double door. The door (number 311) was not sealed (bermed) at the concrete floor (23' elevation). The operator witnessed oil that had migrated into the room. Ultimately, the oil entered the room for a distance of about 20 feet where it was contained. The oil reached MCC-B22, located near to door 311, but did not reach Bus A-6 or load center B2 that are located further away from door 311. The gross affected surface area in the room was approximately 500 square feet, and the oil depth was less than one inch. Efforts to prevent the entry of additional oil into the room were being effected. The operator checked the status of circuit breakers in MCC-B22 and related equipment powered by the breakers for the potential of a fire. The operator concluded that there was no danger of a fire.

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- Two relatively small puddles of oil formed at the eastern end of the main condenser room (6' elevation) on the concrete floor near the main condenser. This location is adjacent to and below the western wall of the room on the 23' elevation where the oil leak emanated. The gross affected surface area was approximately 80 square feet and the depth of oil was less than one inch.

- From the 23' elevation floor drains in the areas affected by the oil spill, the oil entered the floor drainage system that terminates in the turbine building floor drain oil separator and floor drain sump located at the southern end of the radwaste corridor (-1' elevation). The oil did not enter the liquid radwaste system.

- From the stairwell landing (concrete), the operator witnessed oil flowing or descending through the grated, steel stairway onto the concrete floor at the southern end of the radwaste corridor (-1' elevation). The turbine building floor and equipment drain sumps and related pumps, and a floor drain are located in the area immediately below the stairs. The oil was spreading from the area below the stairwell to the adjacent areas that contain floor drains and non-safety related radwaste monitor tanks, monitor tanks pumps, radwaste metering pumps, radwaste hold-up tanks, treated water transfer pumps, instrument and service air compressors (K-104A/B/C), and service air blower (K-105A). Some of the pumps in this area were operating, and the pumps were subsequently stopped as recommended by the operator. The gross affected surface area was approximately 3,000 square feet, and the depth of the oil and water varied because the floor is sloped; on average, the depth was about one to two inches.

- In the turbine building trucklock area, the operator witnessed oil spreading to the northern and eastern walls of the trucklock. At the trucklock door, oil containment had been installed and oil had not migrated past the truck lock door that was open at the time of the event. Other oil containment efforts were being effected. At the northern end of the trucklock, a single door separates the trucklock from a corridor that extends along the eastern side of switchgear room 'B'. The door was not sealed (bermed) at the floor level. The floor is concrete and the same elevation (23') as the area of the oil spill. The operator's assessment was that there was no danger of a fire. Oil eventually spread past the door (number 105) for a distance of about one foot where it was contained. The gross affected surface area was approximately 1,350 square feet and the depth of oil was reported to be greater than one inch.

By 1530 hours and after the operator reported the results of the oil spill investigation to the NWE, the fire brigade was activated and dispatched to the main transformer and adjacent turbine trucklock area. This action was taken as a precautionary measure. No fire or other evidence of oil ignition was observed. After inspecting the oil spill affected areas, the fire brigade leader reported the results to the NWE. Efforts to contain the oil continued. The fire brigade provided continuous coverage in the areas of the oil spill until 0445 hours on March 8, 1997.

The main transformer mechanical disconnects were opened, and the main transformer ground connector was closed by 1537 hours. This action was taken to electrically isolate and ground the main transformer.

The RHR system train 'B' was re-started in the augmented fuel pool cooling mode (AFPC mode II) at 1540 hours with pump 'D' in service. This action was taken in accordance with procedure 2.2.85.2. AFPC flow was established and pump 'D' amperage was monitored because the power supply to the fuel pool cooling system ultrasonic flow transmitters was de-energized.

At 1545 hours, the RPS panel C511 Bus 'A' was aligned to the backup RPS power supply transformer that is powered by MCC-B10 via Bus B6. This action was taken as part of preparation activities for resetting the RPS, PCIS, and RBIS circuitry.

The Town of Plymouth Fire Department arrived at 1558 hours to inspect the areas affected by the oil spill. No fire department assistance was requested, and no fire department action was necessary.

At 1633 hours, the diesel engine driven fire pump was stopped. This action was taken because the fire water suppression header pressure was being maintained by the system's electrically driven jockey pump.

The fuel pool cooling system ultrasonic flow meters were re-energized via temporary power by 1636 hours with indicated AFPC flow at 1700 gpm. The flow was subsequently adjusted to 1750 gpm.

At 1655 hours, industrial safety personnel notified the control room that a check for the presence of explosive gas in the battery rooms 'A' and 'B' had revealed no explosive gas.

By 1700 hours, oil spill required notifications had been completed, and the control room was notified of the completed notifications.

The contracted oil cleanup firm arrived at about 1720 hours. The cleanup firm had been notified of the oil spill by the BECo system dispatcher. The Massachusetts Deparment of Environmental Protection had also been notified of the oil spill by the BECo dispatcher.

At 1738 hours, the 345 Kv switchyard circuit breakers ACB-104 and ACB-105 were re-closed in accordance with switching orders from the regional power authority (REMVEC).

Emergency preparedness related notifications to local communities and agencies of the Commonwealth of Massachusetts were completed, and the NWE was notified of the completed notifications by 1831 hours. The notifications were made by Emergency Preparedness Department personnel in accordance with an emergency preparedness administrative procedure (EP-AD-130).

At 1840 hours, the status of plant systems included the following:

- Bus A5 and applicable portions of its related electrical system were still powered by Bus A8 from the SDT and 23 Kv distribution system. Bus A6 and applicable portions of its related electrical system were still energized by EDG 'B'. The station blackout diesel generator (SBODG) was in standby service; the source of power to its auxiliary equipment, normally energized from Bus A4 by 480 volt load center B4 and MCC-B40, were still de-energized. The startup transformer (SUT) was still tagged out of service and the related switchyard circuit breakers, ACB-102 and ACB-103, were in the closed position with the mechanical disconnects to the SUT in the open position.

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- The 345 Kv tranmission lines 342 and 355 were still energized.
- The RHR system train 'B' was in service in the AFPC mode II.
- The RBCCW system was cross-tied with loop 'B' providing the cooling water service. The RBCCW loop 'B' head tank level was low (in alarm). The SSW train 'B' pump 'E' was in service providing salt service water cooling to the RBCCW loop 'B' heat exchanger.

The NRC Operations Center was notified of the automatic start of EDG 'B' and actuations of the PCIS and RBIS in accordance with 10 CFR 50.72 at 1617 hours. Problem Report 97.9183 was written to document the event.

At 1905 hours, a tour operator was dispatched to the auxiliary building to check on the status of RBCCW pumps. By 1930 hours, the operator reported RBCCW loop 'B' pumps suction pressures were approximately 32 psig. A priority maintenance request (MR 19700713) was issued for the addition of water to the loop 'B' head tank. By 2005 hours, water had been added to the head tank, the tank's low level alarm was clear, and the loop 'B' pumps suction pressures were approximately 33 psig.

A SBODG low engine water temperature alarm occurred at 2104 hours. The water temperature was approximately 76 degrees Fahrenheit. The water temperature is normally maintained in the range of 80 - 130 degrees Fahrenheit in accordance with procedure 2.1.12.2. The heating is by electric immersion water heaters which are powered from MCC-B40 that had been de-energized as a result of the loss of power to Bus A4. After consultation with the system engineer for the EDGs and SBODG, a decision was made by the senior shift licensed operator (NWE) to monitor the water temperature hourly and start the SBODG, and thereby add heat to the SBODG engine, if the water temperature decreased to 60 degrees Fahrenheit.

An unsuccessful attempt to initiate a manual start of the SBODG was made at 2125 hours. The attempt was made for shutdown safety considerations that included the loss of power to the SBODG auxiliaries due to loss of the preferred source of off-site 345 Kv power. The attempt was not successful because the SBODG lockout relay actuated during the start. The lockout was caused by low engine oil pressure (and alarm) during the SBODG engine starting sequence. The operator began to investigate the cause for the low engine oil pressure alarm. After initial investigation, a priority maintenance request (MR 19700716) was issued to correct the problem, and a limiting condition for operation (LCO O97-60) was initiated. A corrective action program document (PR 97.9182) was written to document the unsuccessful attempt to start the SBODG.

After completing the preparations for re-energizing the 4.16 Kv auxiliary power distribution system from the startup transformer (SUT), the switchyard circuit breakers ACB-102 and ACB-103 were opened in accordance with REMVEC switching orders at 0044 hours on March 8, 1997. ACB-102 and ACB-103 were subsequently closed at 0113 hours with the mechanical disconnects closed. This action re-energized the SUT from the 345 Kv transmission line 342 (ACB-103) and line 355 (ACB-102).

On March 8, 1997, at 0125 hours, actitivities began for re-energizing the 4.16 Kv power distribution system from the SUT.

- Bus A2 was re-energized at 0125 hours.

- Bus A4 was re-energized at 0128 hours. This action restored the source of power to electrical loads including the SBODG engine water heaters.

- Bus A3 was re-energized at 0135 hours. This action restored the source of power to electrical loads including load center B7 and related MCCs.

- The SGTS train 'A', powered from Bus A5 and its related electrical system, was started a 0146 hours in preparation for removing the SGTS train 'B' from service for the subsequent transfer of the source of power for Buses A5 and A6.

- The source of power for Bus A5, energized by Bus A8 from the SDT and 23 Kv distribution system since the loss of preferred off-site 345 Kv power, was transferred to the SUT at 0156 hours.

The source of 480 v power to swing Bus B6 was transferred from Bus B2 (powered by Bus A6) to B1 (powered by Bus A5) at 0235 hours. One of the station heating system boilers was started at 0236 hours. The SSW system train 'A'/'B' swing pump 'C', powered by MCC-B10 from Bus A5 via load center B1 and swing Bus B6, was started at 0244 hours, and SSW train 'B' pump 'E', powered by MCC-B 14 from Bus A6 via load center B2, was stopped.

At 0250 hours, the RHR system train 'B' pump 'D', in service and powered from Bus A6, was stopped in accordance with procedure 2.2.85.2.

The source of power for Bus A6, energized by EDG 'B' since the loss of the source of preferred off-site 345 Kv power, was transferred to the SUT at 0253 hours. EDG 'B' was subsequently returned to standby service at 0321 hours.

At 0315 hours, the RHR system was re-started in the AFPC mode II.

The RPS power supply bus 'A' was re-energized from the backup power supply, and bus 'B' was energized by the RPS motor-generator set by 0406 hours.

At 0430 hours, the PCIS Group 2 and RBIS circuitry were reset. The RPS circuitry was reset at 0530 hours.

These actions concluded the recovery from the loss of the source of preferred off-site 345 Kv power.

CAUSE

The direct cause of the event was an electrical fault in the main transformer. Preliminary results of testing and inspection indicate damage to the transformer's phase 'C' low voltage windings and phase 'A' high voltage windings. The root cause analysis had not been completed when this report was prepared. This report will be supplemented after the root cause analysis report is issued. The supplement is expected to be submitted by the end of May 1997.

Personnel in nearby areas at the time of the event heard a loud noise, described as an explosion, experienced a sensation described as a ground movement or vibration, and witnessed the failure (breakage) of the main transformer phase 'C' ceramic lightning arrestor (located on the top surface of transformer).

The insulating oil leak from the main transformer was the result of the failure (breakage) of one of the two low voltage phase 'A' ceramic bushings and consequent leak of main transformer oil through the broken bushing. There are six isophase bus bars, two per phase, that penetrate the main transformer shell. The isophase bus bars are electrically insulated from the transformer's metallic shell by the ceramic bushings. The six low voltage ceramic bushings are approximately 14 inches in diameter and are connected to the side of the main transformer shell at about the 33' elevation, about 4 feet below the top of the transformer shell.

The broken area of the one low voltage phase 'A' ceramic bushing extended approximately 120 degrees in circumference, mostly along the bottom portion, where the bushing is connected at the main transformer shell. The other low voltage phase 'A' ceramic bushing was chipped on the surface (facing the adjacent broken bushing) and the chip did not extend to the inside surface of the bushing. Neither of the two low voltage phase 'B' ceramic bushings exhibited a crack, chip, or breakage. One of the two low voltage phase 'C' ceramic bushings was chipped on the surface but the chip did not extend to the bushing's inside surface. The other phase 'C' bushing did not exhibit a crack, chip, or breakage.

At the main transformer, the three separate, horizontally-oriented isophase bus ducts merge into a contiguous, three sectioned, metallic, bus terminal enclosure (header). Two metallic de-ionizers (filters) are installed in the header, one between phase 'A' and phase 'B', and one between phase 'B' and phase 'C'. The metallic header, particularly the phase 'A' portion, and filters in the header exhibited no apparent damage. Except for the broken phase 'A' bushing, the chipped surfaces of the other two noted bushings, and the broken lightning arrestor, the exterior of the main transformer and isophase bus ducts header exhibited no obvious evidence of damage.

The main transformer is a 3 phase, 60 hertz, shell type power transformer manufactured by the Westinghouse Electric Corporation, Power Transformer Division. Nameplate data includes: Class FOA, insuldur insulation; 700,000 Kva; L. Spec. MGR303-08; wiring diagram MGR303-04; serial number 7001621; 10.1 percent impedance at 700,000 Kva; 700,000 Kva (primary) and 700,000 Kva (secondary) at 55 degrees Centigrade rise; 22,800 low voltage and 345,000 high voltage (wye connected) with the low voltage and high voltage windings delta connected; and oil tank capacity of 15,030 gallons. The main transformer insulating oil is a refined mineral type of oil that also provides a heat transfer medium. The transformer is equipped with type 'B' coolers that utilize immersed, centrifugal type oil pumps for oil circulation. Main transformer heat transfer is accomplished internally by means of the oil and externally by means of ambient air cooling provided by 33 banked fans (3 fans per cooler). The oil preservation system utilizes a nitrogen gas blanket (1 - 2 psig). Main transformer shell pressure protection is provided by a cover mounted, automatic resetting, relief device that trips at a pressure of about 10 psi and recloses at about one-half the tripping pressure.

After the event, approximately 9,600 gallons of oil was removed from the main transformer for disposal. Therefore, a total of approximately 5,400 gallons of insulating oil ultimately leaked from main transformer through the broken phase 'A' ceramic bushing.

- An estimated 1,100 gallons of the oil leaked from the isophase bus header along the side of the transformer, onto the transformer's concrete pad, onto the trap rock in the area adjacent to the concrete pad, and the soil beneath the trap rock.

- The majority, approximately 4,300 gallons, of the oil was transported by the horizontal isophase bus ducts into the area inside the turbine building that is immediately adjacent to the main transformer. A small quantity of oil leaked from sight glass or other fittings that are installed along the bottom portions of the bus ducts. The oil was transported via the phase 'A' and phase 'B' bus ducts to the isophase bus air cooling unit that is located approximately 25 feet from the location where the bus ducts penetrate the turbine building wall. The oil leaked from the isophase bus air cooling unit and propagated as noted earlier in the report.

- None of the oil in the isophase bus ducts was transported past the isophase bus cooling unit. The isophase bus air cooling unit is located on the 23' elevation, between the main transformer and the main generator. The isophase bus ducts and the air ducts connecting the isophase bus ducts to the cooling unit are constructed of the same material, size, and shape. The air ducts are vertically oriented and are connected to the overhead, horizontal isophase bus ducts via tee-type, welded connections. The arrangement of the ducts and location of the air cooling unit relative to the main transformer and main generator, prevented the transport of oil past the air cooling unit in the direction toward the main generator casing, located about 27 feet past the cooling unit.

As discussed previously, oil entered 4.16 Kv switchgear room 'B' as a result of the oil spill. The original fire hazards analysis was performed in the late 1970s in response to the NRC branch technical position APCSB 9.5-1 Attachment A, "Guidelines for Fire Protection for Nuclear Power Plants Docketed prior to July 1, 1976." In 1990, the analysis was updated in response to 10 CFR 50 Appendix R. The original and updated analyses included switchgear room 'B'. The potential for an oil spill and its effects were included in the analyses. Based on industry experience when the analyses were performed, the analyses did not include the entry of oil into switchgear room 'B' as a result of a main transformer oil spill.

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CORRECTIVE ACTION

Corrective action taken included:

The initial efforts for oil containment were initiated immediately. The fire brigade was activated at 1530 hours on March 7, 1997, and remained on continuous watch until after the recovery from the event.

The initial oil cleanup efforts were initiated soon after or by the time the main transformer was isolated. Continued oil cleanup efforts were accomplished within a few days of the event. The cleanup efforts produced approximately 138 barrels containing a mixture of oil and water. Prior to disposal, the oil and water will be separated. Meanwhile, the barrels are being stored in the radwaste area. The combustible loading of the oil in the barrels was evaluated, and a fire watch was established as a result of the evaluation.

The recovery from the loss of preferred off-site 345 Kv power was achieved in accordance with station procedures by 0530 hours on March 8, 1997.

Corrective action planned includes updating the updated fire hazards analysis report prior to reactor startup, replacement of the main transformer and replacement transformer testing prior to returning to commercial service, and installation of a berm or berms (curbs) to control a potential oil spill in the area of the isophase bus ducts and, thereby, prevent oil from entering switchgear room 'B'.

Additional corrective action to be taken will depend upon the root cause analysis.

OTHER ACTION TAKEN

A special test of the SBODG was conducted. The test was performed in accordance with temporary procedure TP 97-054,"Manually Start Blackout Diesel With Loss of MCC B40." The procedure permitted an unloaded test run of the SBODG with MCC-B40 de-energized. After a 10 minute delay following the opening of circuit breaker B402 (feeder breaker from MCC-B40 to the SBODG auxiliaries), the SBODG was started at 0200 hours on March 19, 1997. After running safisfactorily for the prescribed 20 minute test period, the SBODG engine was shut down at 0220 hours. After reviewing the test results, the test was approved. The satisfactory results of the test provide reasonable assurance the SBODG would have started safisfactorily within 10 minutes if a total loss of off-site power condition (station blackout) had occurred on March 7, 1997.

OTHER ACTION BEING TAKEN OR PLANNED

The feeder cables that connect the unit auxiliary transformer (UAT) to the station 4.16 Kv auxiliary power distribution system were tested as part of the ongoing root cause investigation of the main transformer fault. This action was taken because the 4.16 Kv distribution system was energized from the UAT at the time of the event. The initial test results indicated degradation of some of these feeder cables. Problem Report 97.9238 was written to document the finding. The replacement of degraded cables was in progress when this report was prepared. The cause or effect of the degraded cables with respect the main transformer fault will be determined as part of the root cause analysis.

REMEDIAL ACTION BEING TAKEN OR PLANNED

The trap rock in the main transformer area that was contaminated with oil resulting from the main transformer oil spill will be remediated. The remediation of the trap rock and its disposal and disposal of the oil spilled into the turbine buidling and radwaste areas is governed by Commonwealth of Massachusetts environmental regulations. The soil beneath the trap rock and underlying groudwater was tested. An activity use limitation report will be filed with the Massachusetts Department of Environmental Protection, and the main transformer oil spill area will then be considered remediated.

SAFETY CONSEQUENCES

The event posed no threat to public health and safety.

The interruption in spent fuel pool cooling provided by the RHR system (AFPC mode II) resulted in a spent fuel pool temperature increase of approximately two degrees, from approximately 86 to 88 degrees Fahrenheit. There were 2,761 fuel assemblies in the spent fuel pool of which 208 were new, unirradiated fuel assemblies that would be installed as part of the cycle 12 core re-load.

The automatic actuation of the RPS, PCIS, and RBIS were the designed response to the loss of 120 volt ac power to the coils of the normally energized relays that are part of the RPS, PCIS, and RBIS circuitry. At the time of the event, the RPS, PCIS, and RBIS were not required to be operable.

The automatic re-energizing of Bus A5 and related electrical loads and automatic start of EDG 'B' and re-energizing of Bus A6 and related electrical loads were the designed response to the loss of preferred off-site 345 Kv power and configurations that existed at the time of the event. Bus A8, powered from the 23 Kv distribution system via the SDT, automatically energized Bus A5 as designed instead of EDG 'A' because EDG 'A' was tagged out of service for maintenance.

Bus A8 is the backup source of power to safety-related Buses A5 and A6. Bus A8 is designed to be powered from the SDT or SBODG. The SDT is powered by the 23 Kv distribution system. When powered by the SDT, Bus A8 has sufficient capacity to energize Buses A5 and A6 and their related electrical loads. When powered by the SBODG, Bus A8 has sufficient capacity to power Bus A5 or A6 and selected electrical loads powered from Bus A5 or Bus A6. The SBODG was not started and loaded onto Bus A8 as a result of the loss of preferred off-site 345 Kv power because the 23 Kv distribution system was energized at the time of the event and automatically re-energized Bus A5 via at the SDT and Bus A8. Therefore, there were no safety consequences as a result of the unsuccessful start of the SBODG that is discussed in this report. If a loss of preferred off-site 345 Kv power were to occur for a similar reason described in this report or for a different reason while shut down, EDG 'A' and/or EDG 'B' are designed to start and load onto the respective bus to provide power to the related electrical loads.

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A total of approximately 5,400 gallons of insulating oil was discharged from the main transformer as a result of broken phase 'A' bushing at the main transformer.

- An estimated 1,100 gallons of oil was discharged to the area immediately surrouding the transformer. All of the oil discharged to the area immediately surrounding the transformer was contained in the area surrounding the transformer. The trap rock and soil in the area were inspected for evidence of oil. The inspection revealed most of the oil had seeped into the soil surrounding the main transformer.

- Approximately 4,300 gallons of oil was transported into the turbine building in the noted areas.

  For this event, an oil fire did not occur. The main transformer insulating oil is periodically sampled and analyzed. Prior to March 7, 1997, the oil was sampled on February 27, 1997. The analyses of oil samples include a determination of the oil flash point. Flash point is the minimum temperature at which a liquid gives off vapor in sufficient concentration to be ignitable. The flash point of the oil sample taken on February 27, 1997, was 316 degrees Fahrenheit. Therefore, the oil that leaked on March 7, 1997, had a potential for ignition if the oil had been heated to a temperature of approximately 316 degrees Fahrenheit and had come in contact with an ignition source.

- If the oil leak had occurred during power operation and the oil was sufficiently heated, or was to be heated and subjected to sufficient heat from the isophase bus bars, or was heated and subjected to a sufficient heat for another reason, an oil fire could have occurred if the oil had contacted an ignition source. The fire detectors in the area of the main transformer and inside the turbine building area where the oil spill emanated, are designed to detect and transmit a fire alarm to the main control room. Moreover, except for switchgear rooms 'A' and 'B' and the turbine building trucklock, the fire water suppression system utilizes thermally activated devices to automatically trip the preaction sprinkler system. The system is designed to control an oil-based fire hazard. The sprinklers are designed to actuate individually in response to heat generated by a fire. Concurrently, the fire brigade would be activated to respond to the fire. The fire brigade could use additional water from the station fire water system for a water deluge of the fire. The water would function to reduce the temperature of the oil.

  If the oil fire were to progress into the switchgear room 'B' (no berm or curb), the train 'B' equipment powered from the related switchgear breakers, load centers, and motor control centers could have been affected. Assuming the train 'B' equipment were to become inoperable as a result of a fire in the switchgear room, switchgear room 'A' and the train 'A' equipment power from the related switchgear breakers, load centers, and motor control centers would not be affected because of the physical separation and barriers between switchgear rooms 'A' and 'B'. Moreover, each switchgear room is equipped with fire detectors to detect and transmit a fire alarm to the control room and a carbon dioxide hose reel. In response to the fire alarm(s), the fire brigade would be activated, and the brigade could use the carbon dioxide hose reel for fire suppression, or portable carbon dioxide extinguishers for fire suppression, or other portable carts (dry chemical, carbon dioxide, foam-water) for fire suppression.

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This report was submitted in accordance with 10 CFR 50.73 subpart (a)(2)(iv) because the automatic start and loading of EDG 'B', although a designed response to the loss of the source of preferred off-site 345 Kv power and configuration that existed at the time of the event, was not planned.

This report was also submitted in accordance with subpart (a)(2)(iv) because the automatic actuations of the PCIS and RBIS, although a designed response to the loss of the source of preferred off-site 345 Kv power that resulted in the de-energizing of the coils of the systems' relays, were not planned.

This report is also submitted in accordance with subpart (a)(2)(ii) because the oil spill into switchgear room 'B', although occurring while shut down, was a condition not evaluated in the updated fire hazards analysis report.

SIMILARITY TO PREVIOUS EVENTS

A review for similarity was conducted of Pilgrim Station LERs submitted since 1972. The focus of the review were reports that involved a loss of the source of preferred off-site 345 Kv power. The review identified losses of preferred off-site power that occurred during power operation or while shut down. For those events, none involved a main transformer fault.

A review was also conducted of other historical Pilgrim Station events that involved a loss of preferred off-site 345 Kv power. The review identified losses of preferred off-site power that occurred during power operation or while shut down. For those events, none involved a main transformer fault.

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ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Circuit breaker, AC	52
Cooler	CLR
Drain	DRN
Duct	DUCT
Flowmeter	FI
Generator (EDG, SBODG)	DG
Motor	MO
Pump	P
Relay	RLY
Tank	TK
Transformer	XMFR

SYSTEMS	
Component/closed cooling water system (RBCCW)	CC
Containment isolation control system (PCIS/RBIS)	JM
Engineered safety features actuation system (RPS/PCIS/RBIS)	JE
Essential service water system (SSW)	BI
Fire detection system	IC
Fire protection system (water)	KP
Fire protection system (chemical)	KQ
Fuel pool cooling system	DA
Instrument air system	LD
Insulating oil system	LN
Low-voltage power system (480 vac) - Class 1E	ED
Main generator excitation system	TL
Main generator gas purge system	TH
Main generator output power system (main transformer)	EL
Main generator seal oil system	TI
Main generator stator cooling water system	TJ
Medium-voltage power system (4.16 Kv) - Class 1E	EB
Plant protection system (RPS)	JC
Radwaste building	NE
Reactor building	NG
Standby gas treatment system (SGTS)	BH
Switchyard system (ACBs 102, 103, 104, and 105)	FK
Turbine building	NM

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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ONE LINE DIAGRAM - 345 KV SWITCHYARD