NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Limerick Generating Station, Unit 1	0 5 0 0 0 3 5 2	1 OF 0 9

TITLE (4) Plant in Non-Compliance with the Fire Protection Evaluation Report Due to Unavailability of Certain Safe Shutdown Instruments Controls

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
1 0	0 6	8 8	8 8	— 0 3 1 —	0 2	0 4	0 5	8 9		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1
POWER LEVEL (10): 0 6 2

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A) License Condition 2.F
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
R. M. Krich, Senior Engineer, Licensing Section	2 1 5	8 4 1 - 5 1 8 4

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

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

Abstract:

On October 6, 1988 at 2115 hours, it was determined that Limerick Generating Station Unit 1 was not in compliance with the Fire Protection Evaluation Report, which is reportable in accordance with License Condition 2.F, and in a condition that is outside of the design basis. In May 1988, an engineering review indicated that a design basis fire in the control structure would cause a temporary loss of reactor vessel water level and pressure indication at the Remote Shutdown Panel (RSP). In October 1988, the continued review indicated that the same fire would also cause loss of Reactor Core Isolation Cooling (RCIC) control at the RSP. The root cause of this event is two fold: 1) a lack of detailed procedures used in performing the Safe Shutdown analysis, and 2) a misunderstanding and misapplication of the detailed regulatory requirements. A Justification for Continued Operation, including the establishment of a roving fire watch in the affected areas of the control structure was prepared and approved. Modifications are scheduled to ensure the availability of the reactor water level and vessel pressure indication, and RCIC flow indication and control at the RSP in the event of a fire in the control structure. The performance of ongoing studies along with the development of detailed criteria provide actions to prevent recurrence. This event was not reported in a timely manner due to a procedural inadequacy which was corrected.

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JE22
1/1

Unit Conditions Prior to the Event:

Operating Mode 1 (Power Operation)

Reactor Power 62°

Description of the Event:

On October 6, 1988 at 2115 hours, it was determined that Limerick Generating Station Unit No. 1 (Operating License NPF-39) was not in compliance with the Fire Protection Evaluation Report (FPER) resulting in a violation of License Condition 2.C.(3).a and the plant being in a condition not covered by the plant's operating and emergency procedures. This condition was recognized as reportable and a one hour notification was made at 2127 hours in accordance with the requirements of 10 CFR 50.72(b)(1)(ii)(C). This notification also satisfied the twenty-four hour reporting requirement of License Condition 2.F.

License Condition 2.C.(3).a requires that "the Licensee shall maintain in effect all provisions of the approved fire protection program as described in the ... Fire Protection Evaluation Report ..." Section 5.2.3 of the Fire Protection Evaluation Report (FPER) states that" in the unlikely event that the control room becomes uninhabitable, or if there is a fire in the cable spreading room or the auxiliary equipment room, the plant can be shut down from the remote shutdown panel .... The individual components that are used in achieving shutdown from outside the control room (designated as Shutdown Method R) are listed in Table A-22 for Unit 1 ..." In Section 5.2.3 and Table A-22 of the Limerick Generating Station (LGS) FPER, reactor water level and reactor vessel pressure indication are identified as being available to support safe shutdown from outside the control room. Contrary to these commitments, by letter dated May 5, 1988, the Architect/Engineer (A/E), in response to a request by Philadelphia Electric Company (PECo), indicated to the Nuclear Engineering Department that given the design basis fire (an all consuming fire in the control structure i.e., the control room, the cable spreading room or the auxiliary equipment room, coincident with loss of off-site power), all AC power and consequently reactor water level and reactor vessel pressure indication at the Remote Shutdown Panel (RSP) would be unavailable to achieve and maintain Hot Shutdown until manual actions to restore AC power are completed. This review resulted from a PECo initiated A/E review of specific issues associated with the safe shutdown analysis in preparation for Unit 2 licensing.

The unavailability of all AC power is a combined result of both regulatory requirements and fire damage. Regulatory requirements assume a non-mechanistic loss of off-site power concurrent with a non-mechanistic, all consuming fire. For Shutdown Method R, a loss of on-site AC power may result from fire damage to the control circuitry of the Emergency Service Water (ESW) system valves supplying cooling for all of the Emergency Diesel Generators (EDGs). The fire damage could result in closure of the ESW valves thus stopping cooling water flow to the EDGs. Without cocling, the diesel generators would trip off on high coolant temperature and could not be returned to service until manual actions to restore ESW cooling to the EDGs is completed. Loss of both off-site and on-site AC power would result in the loss of reactor vessel water level and pressure indication at the remote shutdown panel. No actions to determine the reportability of this condition were initiated at this time.

In addition, Table A-22 of the LGS FPER also identifies Reactor Core Isolation Cooling (RCIC) pump discharge line flow instrumentation as being available to support safe shutdown from outside the control room. On October 3, 1988, the A/E, during continued review, notified PECo of a potential problem that if fire damage occurs before an operator can manually operate the appropriate isolation transfer switches at the remote shutdown panel, damage may occur to the RCIC speed controller and flow transmitter such that control of RCIC from the RSP would not be available to achieve and maintain Hot Shutdown. This problem was confirmed by the A/E on October 6, 1988.

Considering the above conditions with respect to the assumptions associated with a design basis fire, a viable safe shutdown method to achieve and maintain Hot Shutdown from outside the control room would not exist. These conditions are in conflict with commitments made in the LGS Fire Protection Evaluation Report and therefore constitute a violation of LGS Operating License Condition 2.C.(3).a. This is reportable under License Condition 2.F. These conditions also result in the nuclear power plant being in a condition that is outside of the design basis of the plant and are reportable in accordance with the requirements of 10 CFR 50.73(a)(2)(ii)(B). Note: Although these conditions were originally reported on October 6, 1988 under the provisions of 10 CFR 50.72 (b)(1)(ii)(C) as conditions not covered by the plant's operating and emergency procedures, further evaluation determined that these conditions actually result in the plant being in a condition that is outside of the design basis of the plant and should have been properly reported under 10 CFR 50.72 (b)(1)(ii)(B).

After reviewing and evaluating the circumstances associated with the sequence of events leading up to the determination of reportability on October 6, 1988, we have concluded that the condition concerning the temporary loss of reactor vessel water level and pressure indication at the RSP should have been properly reported to the NRC in accordance with the requirements of 10 CFR 50.72, 10 CFR 50.73, and License Condition 2.F at the time that the deviation was identified in May, 1988.

We are currently investigating other possible deficiencies and, if necessary, will make the proper notifications.

Consequences of the Event:

Administrative controls and existing procedures ensure that potential fire hazards are kept to a minimum. In Fire Areas 22 (Cable Spreading Room), 24 (Control Room) and 25 (Auxiliary Equipment Room), the primary combustible loading is due to power and control cables. The cables used at LGS meet the flame test requirements of the IEEE-383 Standard, and therefore, ignition is extremely unlikely in the absence of an external fire source. In addition, administrative controls exist to prohibit storage and limit the amount of combustible liquids permitted in these fire areas. Therefore, it is very unlikely that a fire will spread instantaneously throughout a fire area.

All three fire areas contain smoke detection. Fire area 22 contains manual and automatic fire suppression capabilities (CO_2 total flood and a sprinkler system); Fire Area 24 is continuously manned and contains manual fire suppression capabilities (halon extinguishers in the Control Room and CO_2 hose reels located outside the Control Room); Fire Area 25 is provided with automatic halon suppression below the raised floor and a water hose reel outside the area. Therefore a fire in these areas would be detected early and most likely contained by the installed fire protection equipment.

We believe that as intended, the LGS Transient Response Implementation Plan (TRIP) procedures would provide the operators a success path to safely shutdown the plant in the event that the design basis fire had occurred. The TRIP procedures, derived from the Emergency Procedure Guidelines developed by the BWR Owners' Group provide distinct symptom-oriented operator guidance in bringing the plant to a cold shutdown condition. Although the TRIPs are not available at the RSP, the operators are trained in their contents and use. Additionally, the TRIPs are available at the Technical Support Center (TSC). Under the circumstances described in this Licensee Event Report (LER), the TSC would be activated in accordance with the LGS Emergency Plan and emergency communications would be established between the RSP and the TSC.

Operability of the reactor vessel pressure and water level instrumentation at the RSP is dependent upon the availability of AC power. Although these instruments are powered by a 24V DC power supply, this DC power is derived from the 120V instrument AC distribution panel. Reactor vessel pressure indicator, PI-42-1R011, and water level indicator, LI-42-1R010, are the only reactor vessel pressure and water level indicators located on the RSP. Although other indicators are provided in the control room and the auxiliary equipment room, these indicators (or their associated cabling) may be damaged by fires occurring in those areas. Local indication of reactor vessel pressure is available at instrument racks 10C004 and 10C027 using indicators PI-42-1R004A and B, which are located at elevation 253 ft. in the reactor enclosure. These indicators could have been used to monitor reactor vessel pressure during shutdown from outside of the control room.

Local indication of reactor vessel water level, however, is not available at the local instrument racks. The TRIP procedures offer guidance on transient operations with loss of level indication. Therefore, based on this guidance, the operators could have depressurized the reactor vessel using manual control of the safety relief valves (SRVs) and reflooded the reactor vessel using any available low pressure systems for injection.

Similarly, in the event of a loss of RCIC flow indication and control at the RSP, the operators could have depressurized the reactor vessel using the SRVs and then used the available, low pressure systems for level control.

The Safe Shutdown Method R evaluation in the FPER recognizes the loss of Division I AC power through spurious operation of the ESW cooling water valves and includes a provision for manual actions to restore ESW cooling to the EDG, and therefore, Division I AC power. These actions are of short duration and only consist of the manual operation of four ESW valves and a local EDG start. These actions are covered by approved procedures.

Cause of the Event:

A PECo self-assessment of the LGS Safe Shutdown (SSD) Analysis was performed to determine the root cause (whether programmatic or isolated occurrence) of this LER and LERs 88-039 (January 3, 1989), 88-040 (January 9, 1989), 89-002-01 (March 31, 1989), and 89-012 (March 14, 1989) concerning deficiencies in SSD capabilities as committed to in the FPER. The topics evaluated by the self-assessment are as follows: shutdown model/assumptions, shutdown systems, shutdown components, shutdown circuits, associated circuits, shutdown procedures, fire area evaluations, and deviations from information provided and approved in the FPER. The results of the assessment showed that the root cause is two fold: 1) a lack of detailed procedures utilized in performing the SSD analysis, and 2) a misunderstanding and misapplication of the detailed regulatory requirements, due in part to the changes in interpretation over the course of licensing the Limerick Generating Station.

The proximate cause of the failure to recognize the temporary unavailability of reactor water level and vessel pressure indication for safe shutdown from the remote shutdown panel in the event of a design basis fire in the control structure is most likely personnel error committed during the original analysis in 1982. The NRC approved safe shutdown analysis recognized the need for manual actions to restore AC power. These manual actions are part of existing procedures that support safe shutdown in the event of a fire. However, the original analysis failed to recognize that certain instrumentation would be unavailable until the appropriate manual actions to restore AC power are accomplished.

The proximate cause of the failure to recognize the unavailability of RCIC control from the RSP in the event of a design basis fire in the control structure is most likely personnel error committed during the original analysis. The loss of RCIC control was not recognized in the original analysis as a result of a misunderstanding of the regulatory guidance since credit was taken for manually isolating the circuits of concern prior to the circuits being damaged by the fire.

The cause of the untimely notification of the existence of the condition identified in May, 1988 concerning reactor vessel water level and pressure indication, was a procedural inadequacy. This was due to a lack of clear guidance with respect to responsibility and organizational interfaces and, consequently, sensitivity, with regard to the timeliness of identifying reportable conditions.

Corrective Actions:

As immediate corrective actions, a Justification for Continued Operation (JCO) was prepared and approved by 2115 hours on October 6, 1988. This condition was recognized as reportable and a one (1) hour notification was made at 2127 hours in accordance with 10 CFR 50.72(b)(1)(ii)(c). This notification also satisfied the twenty-four (24) hour reporting requirement of License Condition 2.F. Also, a roving fire watch patrol has been established for Fire Areas 22 and 25 to provide an additional mechanism to prevent and mitigate the consequences of any fire that could result in the identified conditions. A fire watch is not required to accomplish the same objectives for Fire Area 24 (Control Room) since it is continuously manned.

As interim corrective actions, Special Event procedure (SE-1), "Remote Shutdown", was revised on December 16, 1988, to provide interim guidance to the operations personnel for safe shutdown of the plant in the event that a design basis fire in the control structure causes a loss of reactor vessel pressure and water level indication, or a loss of RCIC control and flow indication at the RSP.

As permanent corrective action, a modification will be performed to provide the RSP with reactor water level and reactor vessel pressure indicators with a dc power source that is continuously available in the event of a design basis fire in Fire Areas 22, 24 and 25. A modification will be performed to add isolation devices as required to ensure the operability of RCIC flow indication and control at the RSP in the event of a fire in the areas of concern. All necessary corrective actions will be implemented prior to the startup of Unit 1 from its second Refueling Outage scheduled for April, 1989.

Actions Taken to Prevent Recurrence:

The corrective actions to prevent recurrence were determined based on the root cause findings of the self-assessment of the LGS SSD analysis. These actions entail the performance of ongoing studies to provide verification of basic compliance and the development of detailed SSD analysis criteria. A listing of the ongoing studies and their schedule for completion is provided below. The following studies will be completed prior to restart of Unit 1 from the current Refueling Outage scheduled for April, 1989.

- Breaker Coordination
- Procedural/Timelines (Preliminary)
- High-Low Pressure Interface
- Multiple High Impedance Faults - Interim Restoration Procedures
- Safe Shutdown Component Selection Criteria
- Unit 2 Startup Interactions on Unit 1 Operations
- Remote Shutdown Panel Halon System
- Limerick Core Uncovery Analysis
- Fuse Control (Procedure Revision)
- Fire Damage Prior to Transfer

The following studies will be completed by June, 1989.

- Procedures/Timelines (Final)
- Valid Process Parameters
- Ventilation Assessment
- Multiple High Impedance Faults (Final)
- Loss of Communications
- Loss of Drywell Cooling

If deficiencies are identified as a result of the ongoing studies, they will be reported, along with applicable corrective actions and interim compensatory measures (if required), through the LER process.

The performance of these ongoing studies, using the proper interpretations and application of regulatory requirements and guidance, will result in the verification of LGS regulatory compliance. This action in conjunction with the development of detailed SSD analysis criteria addresses the identified root cause

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and will therefore, help to ensure that regulatory compliance is maintained.

Immediately following completion of the ongoing studies, PECo will implement an enhancement program to re-format the SSD analysis documentation and provide for long term configuration management of the SSD analysis. The by-products of the enhancement effort are expected to be the following.

- o Safe Shutdown Component re-verification
- o Spurious operation re-verification
- o Safe Shutdown Cable re-verification
- o Safe Shutdown capability re-verification

This effort will format the SSD analysis documentation similar to that for Peach Bottom Atomic Power Station, Units 2 and 3.

An enhanced reportability process has been developed to address the issue of timely identification and reporting of deviations. The implementation of this reportability process is intended to produce a heightened sensitivity and provide specific direction to Nuclear Group personnel with regard to recognizing and processing potentially reportable events or conditions. The enhanced reportability process also provides for escalating potentially reportable deviations to higher levels of management if a final reportability determination is not made within a specified period of time.

The implementation of this enhanced reportability process at Limerick Generating Station will be accomplished through the issuance of a station Administrative Procedure. We anticipate that the enhanced reportability process will be implemented within the entire Nuclear Group by December 1, 1988.

EIIS Codes:
System Codes:

NA	Central Control Complex
LB	Diesel Cooling Water System
EK	Emergency Onsite Power Supply System
IC	Fire Detection System
KP	Fire Protection System
EE	Instrument and Uninterruptible Power System
BN	Reactor Core Isolation Cooling System
BI	Essential Service Water System

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Component Codes:

LI	Indicator, Level
PI	Indicator, Pressure
PL	Panel
V	Valve
DG	Generator, Diesel
HS	Switch, Hand
SC	Control, speed
FT	Transmitter, flow
CBL	Cable
DET	Detector

Previous Similar Occurrences:

LGS LERs 87-055, 86-055, 85-087 and 85-057 reported non-compliance with FPER requirements. LGS LER 88-030 reported untimely NRC notification.