REGULATORY DOCKET FILE COPY

Distribution
Docket
ORB #3
NRR Reading
Local PDR
NRC PDR
DEisenhut
WGammill
RVollmer
BGrimes
JMiller
LShao
TIppolito
SNorris
RBevan
DZiemann
SNowicki
JLee
WKane
CThomas
DRoss
Atty, OELD
I&E (3)
NSIC
TERA
ACRS (16)
HDenton
ECase
DVassallo
CHeltemes
TNovak
ZRosztoczy
OParr
JStolz
SIsrael
CDeBevec
EJordan
PBoehnert
RFrahm
JGuttman
EThrom
B&O File
WHodges
PMatthews
GMazetis
PNorian
NWagner
KMahan

Docket Nos. 50-237
50-249
50-254
and 50-265

MARCH 1 0 1980

Mr. D. Louis Peoples
Director of Nuclear Licensing
Commonwealth Edison Company
P. O. Box 767
Chicago, Illinois 60690

Dear Mr. Peoples:

SUBJECT: NRC STAFF EVALUATION OF COMMONWEALTH EDISON COMPANY RESPONSES TO IE BULLETIN 79-08 FOR DRESDEN STATION, UNITS 2 AND 3 AND QUAD CITIES STATION, UNITS 1 AND 2

We have completed our review of the information that you provided in your letters dated April 27 and August 3, 1979 in response to IE Bulletin 79-08 for the Dresden Station Units 2 and 3 and Quad Cities Station Units 1 and 2.

We have concluded that you have taken the appropriate actions to meet the requirements of each of the eleven action items identified in IE Bulletin 79-08. A copy of our evaluation is enclosed.

As you know, NRC staff review of the Three Mile Island, Unit 2 (TMI-2) accident is continuing and other corrective actions may be required at a later date. Specific requirements for your facility that result from this review and other TMI-2 investigations will be addressed to you in separate correspondence.

Sincerely,

Original signed by

Thomas A. Ippolito, Chief
Operating Reactors Branch #3
Division of Operating Reactors

A01/1

Dupe

8003270220

Enclosure:
NRC Staff Evaluation

cc w/enclosure:
See next page

	ORB #3	ORB #2	ORB #2		
	RBevan:mjf	SNowicki	DZiemann		
	3/5/80	3/6/80	3/7/80		
OFFICE	B&O	B&O	D:DPM	ORB #3	
SURNAME	CThomas	WKane	DRoss	TIppolito	
DATE	3/10/80	3/10/80	3/10/80	3/10/80	

cc:

Mr. D. R. Stichnoth
President
Iowa-Illinois Gas and
Electric Company
206 East Second Avenue
Davenport, Iowa 52801

Mr. John W. Rowe
Isham, Lincoln & Beale
Counselors at Law
One First National Plaza, 42nd Floor
Chicago, Illinois 60603

Mr. Nick Kalivianakas
Plant Superintendent
Quad Cities Nuclear Power Station
22710 - 206th Avenue - North
Cordova, Illinois 61242

Anthony Z. Roisman
Natural Resources Defense Council
917 15th Street, N. W.
Washington, D. C. 20005

Moline Public Library
504 - 17th Street
Moline, Illinois 61265

Susan N. Sekuler
Assistant Attorney General
Environmental Control Division
188 W. Randolph Street
Suite 2315
Chicago, Illinois 60601

Mr. N. Chrissotimos, Inspector
US Nuclear Regulatory Commission
Box 756
Bettendorf, Iowa 52722

Mr. B. B. Stephenson
Plant Superintendent
Dresden Nuclear Power Station
Rural Route #1
Morris, Illinois 60450

Jimmy L. Barker
U. S. Nuclear Regulatory Commission
P. O. Box 706
Morris, Illinois 60450

EVALUATION OF LICENSEE'S RESPONSES

TO

IE BULLETIN 79-08

COMMONWEALTH EDISON COMPANY

DRESDEN STATION, UNITS 2 AND 3

DOCKET NOS. 50-237 AND 50-249

Introduction

By letter dated April 14, 1979, we transmitted Office of Inspection and Enforcement (IE) Bulletin 79-08 to Commonwealth Edison Company (CECo or the licensee). IE Bulletin 79-08 specified actions to be taken by the licensee to avoid the occurrence of an event similar to that which occurred at Three Mile Island, Unit 2 (TMI-2) on March 28, 1979. By letter dated April 27, 1979, CECo provided responses to Action Items 1 through 11 of IE Bulletin 79-08 for the Dresden Station, Units 2 and 3 (Dresden 2 and 3).

The NRC staff review of the CECo responses led to the issuance of requests for additional information regarding the CECo responses to certain action items of IE Bulletin 79-08. These requests were contained in a letter dated July 20, 1979. By letter dated August 3, 1979, CECo responded to the staff's requests for additional information.

The CECo responses to IE Bulletin 79-08 provided the basis for our evaluation presented below. In addition, the actions taken by the licensee in response to the bulletin and subsequent NRC requests were verified by onsite inspections by IE inspectors.

Evaluation

Each of the 11 action items requested by IE Bulletin 79-08 is repeated below followed by our criteria for evaluating the response, a summary of the licensee's response and our evaluation of the response.

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 March 28, 1979 accident included in Enclosure 1 to IE Bulletin 79-05A.

   a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

b. Operational personnel should be instructed to (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 5a of this bulletin); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

The licensee's response was evaluated to determine that (1) the scope of review was adequate, (2) operational personnel were properly instructed and (3) personnel participation in the review was documented in plant records.

The licensee's response dated April 27, 1979 states that a review of the information given in Enclosure 1 to IE Bulletins 79-05 and 79-05A was being performed. The review emphasized the five points stressed in 1.a and b of IE Bulletin 79-08. In accordance with Item 1.c, the licensee stated that documentation of this review by all licensed operators and plant management and supervisors with operational responsibilities would be provided and maintained on file. The licensee's supplemental response dated August 3, 1979 confirmed that all actions required by Item 1 had been completed by June 1, 1979.

We conclude that the licensee's scope of review, instructions to operating personnel and documented participation satisfy the intent of IE Bulletin 79-08, Item 1.

2. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

The licensee's response was evaluated to verify that containment isolation initiation design and procedures had been reviewed to assure that (1) manual or automatic initiation of containment isolation occurs on automatic initiation of safety injection and (2) all lines (including those designed to transfer radioactive gases or liquids) whose isolation does not degrade cooling capability or needed safety features were addressed.

The licensee's response of April 27, 1979 states that a review of the existing isolation design and procedures had been performed to determine whether all systems not needed for safety injection would isolate on injection signal. The review verified that a safety injection signal would automatically initiate containment isolation, if containment isolation had not already been initiated, by closure of all valves where such closure does not degrade needed safety features or cooling capability. In addition, applicable emergency operating procedures were reviewed to assure proper operator action in the event of automatic initation of containment isolation.

In its supplemental response dated August 3, 1979, the licensee determined that an automatic isolation should be added to the torus-to-main condenser drain line. By a subsequent telephone conversation, the licensee advised us that this modification has been completed. The licensee also implemented a procedure change to manually close the torus-to-main condenser drain line if isolation is initiated. The licensee further confirmed in its August 3, 1979 letter that its review had included all lines penetrating primary containment and that the review included the applicable emergency instructions and operating procedures. No changes to the design or procedures were reported as needed other than the aforementioned.

We conclude that the licensee's review of containment isolation initiation design and procedures satisfies the intent of IE Bulletin 79-08, Item 2.

3. Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

The licensee's response was reviewed to assure that (1) it described the automatic and manual actions necessary for the proper functioning of the auxiliary heat removal systems when the main feedwater system is not operable and (2) the procedures for any necessary manual actions were described in summary form.

The licensee's response dated April 27, 1979 states that, following a loss of feedwater, reactor scram occurs at low water level (+8 inches). In about 34 seconds, reactor water will fall to low-low level (-59 inches) at which time high pressure coolant injection (HPCI) system operation and main steam isolation valve (MSIV) closure will be initiated. Main steam relief valves may open shortly following MSIV closure, relieving steam to the suppression pool.

With no operator action, the HPCI system will continue adding water to the vessel until the level reaches high level (+48 inches), at which time the HPCI system turbine will automatically trip. The HPCI system turbine will automatically restart if the low water level signal is again reached and the turbine trip signal clears. All system operation of HPCI is automatic. From this point on, cooldown would continue with removal of decay heat using the isolation condenser (IC), a passive system.

Following closure of the MSIV's, the IC will be initiated 15 seconds after reactor pressure rises to 1070 psig. The IC's are designed to provide core cooling in the event that the reactor is isolated from the main condenser by closure of the MSIV's. The IC is sized to handle all core decay heat at five minutes after a scram. This heat removal capability is verified once every five years in accordance with the Technical Specifications.

Once initiated automatically, the water inventory of the IC shell side is adequate to allow 20 minutes of operation before the water level reaches the top of the tubes without adding any makeup. This 20 minutes is adequate to allow for manual initiation of makeup flow to the shell. The shell side water inventory required to assure IC operability is defined in the Technical Specifications and the station operating procedures.

Station procedures define the proper methods of initiating makeup to the IC shell from any one of three sources of makeup water. The station procedures also outline the actions necessary to manually initiate the IC, including making up to the shell.

If the IC is unavailable, the relief valves would be used to control reactor depressurization. This is performed by manually opening a relief valve from the main control room. The use of the HPCI system for reactor makeup (either manually or by allowing automatic initiation) would provide additional depressurization of the reactor. After depressurization to 350 psig, the low pressure coolant injection (LPCI) or core spray (CS) systems could also be used for reactor water makeup.

If both the HPCI system and the IC are unavailable, the relief valves would be used to manually depressurize the vessel to less than 350 psig when, in conjunction with a low-low reactor water level of -59 inches, the LPCI and CS systems would be automatically initiated. Once the reactor water level has been recovered and it has been absolutely determined that the LPCI and CS systems are no longer needed, these systems would be manually shut down.

Although the capability of the aforementioned systems to perform as indicated is described during initial operator training and in subsequent retraining, no specific procedure existed which dealt with the loss of feedwater and possible unavailability of both the HPCI system and the IC.

In its supplemental response dated August 3, 1979, the licensee stated that operating procedures have been revised to specifically instruct operators to manually depressurize the reactor using the relief valves, allowing the LPCI and CS systems to inject water if the normal feedwater and HPCI systems and the IC are unavailable. By a subsequent telephone conversation, the licensee advised us that all licensed operators have received training in these revised procedures and documentation of this training is being kept on file.

We conclude that the licensee's procedural summary of automatic/manual actions necessary for the proper functioning of auxiliary heat removal systems used when the main feedwater system is inoperable satisfies the intent of IE Bulletin 79-08, Item 3.

4. Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information regarding plant status. Instruct operators to utilize other available information to initiate safety systems.

The licensee's response was evaluated to determine that (1) all uses and types of vessel level indication for both automatic and manual initiation of safety systems were addressed, (2) it addressed other instrumentation available to the operator to determine changes in reactor coolant inventory and (3) operators were instructed to utilize other available information to initiate safety systems.

The licensee's response of April 27, 1979 states that vessel level indication for both automatic and manual initiation is achieved by diverse and redundant instrumentation. The vessel level indication is comprised of four types of instruments. Two of the four types, the narrow and the wide range Yarway indicators, are used for the manual and/or automatic initiation of the safety systems.

(1) The narrow range Yarway level instrumentation has a range of +60 inches to -60 inches. This covers the normal operating ranges down to the lower instrument nozzle. Operation of this instrumentation requires no power supply, and it provides most of the trip functions associated with the water level instrumentation. It is referenced to "instrument zero," is calibrated at 1000 psig reactor pressure, and is rapid-pressure-change-compensated. The setpoints and functions of the narrow range Yarway include:

Setpoints	Functions
+55 inches	Trips main turbine, HPCI system turbine and main feedwater pumps.
+30 inches	Automatic feedwater runout reset. Inhibits runout flow control above +30 inches. Normal operating level.
+8 inches	Reactor scram. Initiates Groups 2 and 3 containment isolation closure.
-59 inches	Initiates ECCS. Initiates standby diesel-generators. Trips recirculation pumps. Completes Group 1 containment isolation.

Two narrow range Yarway level indicators are located in the main control room, and ten level indicating switches with indicators are located in the reactor building.

(2) The wide range Yarway level instrumentation has a range of 400 inches, covering the active core range and overlapping the lower portion of the narrow range Yarway. This provides indication during and after a blowdown accident and with the recirculation pumps tripped. It also provides a signal to prevent the residual heat removal (RHR) system from operating in the containment spray mode when the level is below 2/3 core height. Two wide-range Yarway indicators are located in the control room.

In addition to the Yarway level instruments, there are narrow and wide range GE/MAC level instruments which can be used by the operator to monitor vessel water level.

(3) The narrow range GE/MAC level instrumentation is the most accurate level indication available to the operator. It provides the level input to the feedwater level control system. Its range of zero to 60 inches, referenced to instrument zero, covers the normal operating range. It is calibrated at 1000 psig and is temperature compensated.

The recorder alarms in the control room at high and low water levels. The level indications can also be displayed on the control room digital window display and recorded on the control room computer printout.

The wide range GE/MAC level instrumentation provides level indication during vessel flooding on cooldown. Its range is 400 inches and covers the upper portion of the reactor vessel. One wide range GE/MAC level indicator is located in the main control room. The wide range GE/MAC level indications can also be displayed on the main control room digital window display and recorded on the control room computer printout.

In addition to the above indications available to the operator, alarms associated with the automatic actions listed above will inform the operator of the reactor vessel level status and require his verification that actions have taken place at the appropriate levels.

As listed in the licensee's supplemental response dated August 3, 1979, the control room operator has numerous alternate indications that can indirectly indicate a change in reactor vessel coolant inventory. Instrumentation is available in the control room to monitor:

Drywell Pressure
Drywell Temperature
Suppression Chamber Pressure
Suppression Chamber Temperature
Suppression Chamber Water Level
Feedwater Flow
Steam Flow
Reactor Pressure
Relief Valve Discharge Temperature
Drywell Floor and Equipment Sump Discharge Flow
Reactor Building Closed Cooling Water Temperature

Any of these measured parameters could indirectly indicate a change in reactor vessel coolant inventory.

The licensee's August 3, 1979 letter states that the operators have been instructed to utilize other available information as part of their training as required by Item 1 of IE Bulletin 79-08. In addition, the use of multiple indications to identify abnormal conditions is an underlying philosophy of the licensee's abnormal and emergency procedures. All licensed operators are trained on these procedures annually as part of their requalification training.

We conclude that the licensee's description of the uses and types of reactor vessel level/inventory instrumentation and instructions to operators regarding the use of this information satisfies the intent of IE Bulletin 79-08, Item 4.

5. Review the actions directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions (e.g., vessel integrity).

   b. Operators are provided additional information and instructions to not rely upon vessel level indication alone for manual actions, but to also examine other plant parameter indications in evaluating plant conditions.

The licensee's response was evaluated to determine that (1) it addressed the matter of operators improperly overriding the automatic actions of engineered safety features, (2) it addressed providing operators with additional information and instructions to not rely upon vessel level indication alone for manual actions and (3) that the review included operating procedures and training instructions.

In its response dated April 27, 1979, the licensee stated that safety systems are to be operated in their normal automatic mode, and that manual control is taken only in extreme cases to prevent unsafe plant conditions, equipment damage, or personnel injury. The standing operating orders and administrative procedures reflect this, and they address other requirements pertaining to instrument indications, administering ECCS, administering the standby liquid control system, operating within safety limits, and departure from approved procedures.

The licensee has advised us that based on the reviews it performed in response to IE Bulletin 79-08, all revisions to the standing operating orders and administrative procedures have been implemented. In addition, the operating procedures associated with reactor water level control and/or ECCS have been reviewed for notes concerning the overriding of engineered safety features and the proper use of level instrumentation for operational decisions.

In its supplemental response dated August 3, 1979, the licensee confirmed that the review of operating procedures and training did include verification that operators are directed to use multiple symptoms in evaluating plant conditions and are not to rely solely on vessel level indication when taking manual actions during transients.

We conclude that the licensee's review of operating procedures and training instructions satisfies the intent of IE Bulletin 79-08, Item 5.

6. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system start-up, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

The licensee's response was evaluated to assure that (1) safety-related valve positioning requirements were reviewed for correctness, (2) safety-related valves were verified to be in the correct position and (3) positive controls were in existence to maintain proper valve position during normal operation as well as during surveillance testing and maintenance.

The licensee's response dated April 27, 1979 described the review of safety-related valve positioning requirements and described how such valves are verified to be in the correct positions.

The positions of vital manual ECCS valves are controlled by the use and documentation of locks on the handwheels. Motor-operated valves on safety systems are positioned so as to require minimal automatic valve actions upon system initiation. Moreover, ECCS initiation logic is such that valves may be in off-positions, but will go to their proper positions under initiation conditions. The only valves which do not automatically open if closed are normally open and have key-lock switches in the control room.

Surveillance and testing procedures for safety-related equipment include step-by-step checklists to verify proper lineup of equipment following testing. Each procedure is reviewed by station management as an additional verification of proper return to an operational state.

Additionally, when safety-related equipment is removed from service for maintenance, the equipment outage procedure requires documentation of its proper removal and return to service. Functional tests of the equipment are also required by this procedure when the equipment is placed into operation to ensure operability and proper response of the system.

In its supplemental response dated August 3, 1979, the licensee confirmed that both station personnel and the NRC Region III resident inspector have verified the correct alignment for operation of all accessible valves in the safety systems. Since shortly after the TMI accident, the suction valves to the ECCS pumps have been verified open daily. Finally, the licensee has implemented a procedure to verify daily that all accessible ECCS valves in the main flow paths are in their proper positions.

We conclude that the licensee's review of safety-related valve positioning requirements, valve positions and positive controls to maintain proper valve positions satisfies the intent of IE Bulletin 79-08, Item 6.

7. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists.

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

The licensee's response was evaluated to determine that (1) it addressed all systems designed to transfer potentially radioactive gases and liquids out of primary containment, (2) inadvertent releases do not occur on resetting engineered safety features instrumentation, (3) it addressed the existence of interlocks, (4) the systems are isolated on the containment isolation signal, (5) the basis for continued operability of the features was addressed and (6) a review of the procedures was performed.

In its April 27, 1979 response, the licensee identified the following lines used to transfer potentially radioactive liquids and gases from the primary containment:

Drywell floor drain sump discharge
Drywell equipment drain sump discharge
Drywell and suppression chamber ventilation
Torus transfer to the condenser hotwell

Valves on all the above lines isolate the primary containment during a Group 2 isolation. This isolation is initiated on high drywell pressure (+2 psig) or low reactor water level (+8 inches), both indicating a possible leak to the containment. A seal-in circuit is used to prevent the valves from returning to their original positions upon reset of the initiating instrumentation. A manual reset performed by the operator is needed to return to the original valve lineup. With the isolation signal present, however, no sump discharge or torus water transfer can take place, and gas venting through two-inch valves to the standby gas treatment system can only be done after using a key-lock bypass switch. Procedural controls and annunciator indication govern operation of this bypass feature. No interlocks presently exist to prevent gas or liquid transfer from the containment when a containment high radiation condition exists.

While performing the review of the above isolations, it became evident that upon manual reset of the isolation, after isolation initiation conditions have cleared, open paths to the containment could exist. This is exemplified by the drywell sump discharge line valves. Upon isolation reset, these valves will reopen and the sump pumps will start on high sump level, pumping potentially high activity material from the containment. The practice of leaving these valves in the closed position and only opening them during the periodic pumping down of the sumps to radwaste has been instituted along with procedural controls to close these valves and leave them closed after a Group 2 isolation. The valves will not be opened until containment atmosphere and reactor coolant samples can be taken to insure that high activity materials have not been released to the containment.

The drywell and torus ventilation valves would respond in a similar manner. If a purge of the drywell were in progress at the time a Group 2 isolation occurred, the valves on the vent lines would return to the open position, opening a path out of the containment upon reset of the isolation. The licensee has instituted procedural controls which specify that the Group 2 isolation valves be placed in the closed position before a manual reset is attempted.

In summary, lines which transfer radioactive materials from the primary containment are isolable. These isolations do not automatically reset by the reset of the initiation instrumentation only, but also require a manual reset.

This logic provides a means of controlling releases. The isolations are also tested according to the Technical Specifications to assure operability.

In its supplemental response dated August 3, 1979, the licensee stated that the procedure changes discussed above have been initiated. By a subsequent telephone conversation, the licensee advised us that these procedure changes have been completed.

We conclude that the licensee's review of systems designed to transfer radioactive gases and liquids out of primary containment to assure that undesired pumping, venting, or other release of radioactive liquids and gases will not occur satisfies the intent of IE Bulletin 79-08, Item 7.

8. Review and modify as necessary your maintenance and test procedures to ensure that they require:

   a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

   b. Verification of the operability of safety-related systems when they are returned to service following maintenance or testing.

   c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

The licensee's response was evaluated to determine that operability of redundant safety-related systems is verified prior to the removal of any safety-related system from service. Where operability verification appeared only to rely on previous surveillance testing within Technical Specification intervals, we asked that operability be further verified by at least a visual check of the system status to the extent practicable, prior to removing the redundant equipment from service. The response was also evaluated to assure provisions were adequate to verify operability of safety-related systems when they are returned to service following maintenance or testing. We also checked to see that all involved reactor operational personnel in the oncoming shift are explicitly notified during shift turnover about the status of systems removed from or returned to service since their previous shift.

In its April 27, 1979 response, the licensee stated that existing procedures require that redundant and required backup systems are functionally tested prior to removal of safety-related equipment from service for planned maintenance or testing. This practice includes testing of each subsystem and backup system prior to removal of the equipment from service and testing thereafter in accordance with the Technical Specifications until such equipment is returned to an operational status.

Safety-related equipment maintenance or testing procedures also require system functional tests to verify operability when equipment is returned to service. These tests verify proper operation through all isolation points required for its removal from service.

Surveillance procedures or maintenance work packages which require safety-related equipment outages require a shift supervisor's approval prior to removing equipment from service. This approval is given after proper testing or verification of redundant equipment is performed. When the equipment is returned to service, these packages or procedures again require a shift supervisor's notification for review and testing prior to declaring the component operable.

In its supplemental response dated August 3, 1979, the licensee stated that an administrative procedure for Dresden 2 and 3 has been proposed to govern shift turnover practices. The procedure explicitly requires the oncoming operators to be informed of the status of equipment taken out of service or returned to service, any off-normal equipment lineups, activities in progress or planned, the status of caution cards and jumpers, and surveillance in progress or planned. Following a review by the oncoming operators of the high radiation area entry log and a review of panel indications, the offgoing operator signs the surveillance log to indicate that he has properly turned over the shift operations. By a subsequent telephone conversation, the licensee advised us that this procedure change has been completed.

We conclude that the licensee's review and modification of maintenance, test and administrative procedures to assure the availability of safety-related systems and operational personnel knowledge of system status satisfies the intent of IE Bulletin 79-08, Item 8.

9. Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

The licensee's response was evaluated to determine that (1) prompt reporting procedures required or were to be modified to require that the NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation and (2) procedures required or were to be modified to require the establishment and maintenance of an open continuous communication channel with the NRC following such events.

In its April 27, 1979 response, the licensee stated that the existing Generating Stations Emergency Plan requires procedures for notification of the NRC as well as other regulatory agencies in the event of an emergency situation such as described in this item. In such an event, the shift engineer will immediately notify the system load dispatcher, who in turn will notify the command center director on duty, who will place an immediate call to the NRC. In the event that the load dispatcher cannot reach the duty command center director within five minutes, the load dispatcher will then notify the NRC.

The command center procedure requires that specific telephones be designated as open lines in which continuous communications could be established.

Based on the licensee's review of the existing Generating Stations Emergency Plan and its implementing procedures, the licensee believes that notification of the NRC within one hour and maintenance of an open line of communication are assured should the conditions specified ever exist.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 9.

10. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

The licensee's response was evaluated to determine if it described the means or systems available to remove hydrogen from the primary system as well as the treatment and control of hydrogen in the containment.

In its response dated April 27, 1979, the licensee stated that it had reviewed the operating modes and procedures dealing with the generation of hydrogen gas either in the primary system or released to the containment during a transient.

The reactor head is continuously vented to the "A" main steam line and, therefore, any hydrogen gas generated during a transient could be released to the containment via the "A" main steam line relief valve, which relieves directly to the suppression pool. In addition, the reactor head can also be vented directly to the containment by means of two vent valves, which are remotely operated from the main control room. However, these valves are not normally opened without first depressurizing the system.

The hydrogen gas released to the containment is controlled by means of the containment nitrogen inerting system. The containment atmosphere oxygen concentration can be reduced to less than five percent with nitrogen gas within a 24-hour period, subsequent to placing the reactor mode switch in the "run" position following a shutdown. The five percent oxygen concentration minimizes the possibility of hydrogen combustion following a loss-of-coolant accident.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 10.

11. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the items above.

The licensee's response was evaluated to determine that a review of the Technical Specifications had been made to determine if any changes were required as a result of implementing Items 1 through 10 of IE Bulletin 79-08.

In its letter dated April 27, 1979, the licensee reported that, based on its review and investigative program performed in response to Items 1 through 10 of IE Bulletin 79-08, no modification to the Technical Specifications for Dresden 2 and 3 are appropriate, so none were proposed.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 11.

Conclusion

Based on our review of the information provided by the licensee to date, we conclude that the licensee has correctly interpreted IE Bulletin 79-08. The actions taken demonstrate the licensee's understanding of the concerns arising from the TMI-2 accident in reviewing their implementation on Dresden 2 and 3 operations, and provide added assurance for the protection of the public health and safety during the operation of Dresden Station, Units 2 and 3.

References

1. IE Bulletin 79-05, dated April 1, 1979.

2. IE Bulletin 79-05A, dated April 5, 1979.

3. IE Bulletin 79-08, dated April 14, 1979.

4. CECo letter, C. Reed to J. Keppler, dated April 27, 1979.

5. NRC staff letter, T. Ippolito to C. Reed, dated July 20, 1979.

6. CECo letter, C. Reed to T. Ippolito, dated August 3, 1979.

EVALUATION OF LICENSEE'S RESPONSES

TO

IE BULLETIN 79-08

COMMONWEALTH EDISON COMPANY

QUAD CITIES STATION, UNITS 1 & 2

DOCKET NOS. 50-254 AND 50-265

Introduction

By letter dated April 14, 1979, we transmitted Office of Inspection and Enforcement (IE) Bulletin 79-08 to Commonwealth Edison Company (CECo or the licensee). IE Bulletin 79-08 specified actions to be taken by the licensee to avoid the occurrence of an event similar to that which occurred at Three Mile Island, Unit 2 (TMI-2) on March 28, 1979. By letter dated April 27, 1979, CECo provided responses to Action Items 1 through 11 of IE Bulletin 79-08 for the Quad Cities Station, Units 1 and 2 (Quad Cities 1 and 2).

The NRC staff review of the CECo responses led to the issuance of requests for additional information regarding the CECo responses to certain action items of IE Bulletin 79-08. These requests were contained in a letter dated July 20, 1979. By letter dated August 3, 1979, CECo responded to the staff's requests for additional information.

The CECo responses to IE Bulletin 79-08 provided the basis for our evaluation presented below. In addition, the actions taken by the licensee in response to the bulletin and subsequent NRC requests were verified by onsite inspections by IE inspectors.

Evaluation

Each of the 11 action items requested by IE Bulletin 79-08 is repeated below followed by our criteria for evaluating the response, a summary of the licensee's response and our evaluation of the response.

1. Review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 March 28, 1979 accident included in Enclosure 1 to IE Bulletin 79-05A.

    a. This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both trains of a safety system at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; and (3) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective action.

b. Operational personnel should be instructed to (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 5a of this bulletin); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

c. All licensed operators and plant management and supervisors with operational responsibilities shall participate in this review and such participation shall be documented in plant records.

The licensee's response was evaluated to determine that (1) the scope of review was adequate, (2) operational personnel were properly instructed and (3) personnel participation in the review was documented in plant records.

The licensee's response dated April 27, 1979 states that a review of the information given in Enclosure 1 to IE Bulletins 79-05 and 79-05A was being performed. The review emphasized the five points stressed in Items 1.a and b of IE Bulletin 79-08. In accordance with Item 1.c, the licensee stated that documentation of this review by all licensed operators and plant management and supervisors with operational responsibilities would be provided and maintained on file. The licensee's supplemental response dated August 3, 1979 confirmed that all actions required by Item 1 had been completed by July 25, 1979.

We conclude that the licensee's scope of review, instructions to operating personnel and documented participation satisfy the intent of IE Bulletin 79-08, Item 1.

2. Review the containment isolation initiation design and procedures, and prepare and implement all changes necessary to initiate containment isolation, whether manual or automatic, of all lines whose isolation does not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

The licensee's response was evaluated to verify that containment isolation initiation design and procedures had been reviewed to assure that (1) manual or automatic initiation of containment isolation occurs on automatic initiation of safety injection and (2) all lines (including those designed to transfer radioactive gases or liquids) whose isolation does not degrade cooling capability or needed safety features were addressed.

The licensee's response of April 27, 1979 states that a review of the existing isolation design and procedures had been performed to determine whether all systems not needed for safety injection would isolate on injection signal. The review verified that a safety injection signal would automatically initiate containment isolation, if containment isolation had not already been initiated, by closure of all valves where such closure does not degrade needed safety features or cooling capability. In addition, applicable emergency operating procedures were reviewed to assure proper operator action in the event of automatic initiation of containment isolation. In its supplemental response dated August 3, 1979, the licensee confirmed that a procedure change had been initiated to provide for proper operator action in the event of a reactor building closed cooling water (RBCCW) system return line break inside the drywell.

The licensee further confirmed that its review included all lines penetrating primary containment and that the review included the applicable emergency instructions and operating procedures. No changes to design or procedures were reported by the licensee other than the procedure change for operator action for the aforementioned RBCCW system return line break inside the drywell.

We conclude that the licensee's review of containment isolation initiation design and procedures satisfies the intent of IE Bulletin 79-08, Item 2.

3. Describe the actions, both automatic and manual, necessary for proper functioning of the auxiliary heat removal systems (e.g., RCIC) that are used when the main feedwater system is not operable. For any manual action necessary, describe in summary form the procedure by which this action is taken in a timely sense.

The licensee's response was reviewed to assure that (1) it described the automatic and manual actions necessary for the proper functioning of the auxiliary heat removal systems when the main feedwater system is not operable and (2) the procedures for any necessary manual actions were described in summary form.

The licensee's response dated April 27, 1979 states that following a loss of feedwater, reactor scram occurs at low water level (+8 inches). In about 34 seconds, reactor water level will fall to low-low level (-59 inches), at which time high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system operation and main steam isolation valve (MSIV) closure will be initiated. Main steam relief valves may open shortly following MSIV closure, relieving vessel pressure to the suppression pool.

With no operator action, the HPCI and RCIC systems will continue adding water to the vessel until the level reaches high level (+48 inches) at which time the HPCI and RCIC system turbines will automatically trip. The HPCI system turbine will automatically restart if the low water level signal is again reached and the turbine trip signal clears. The RCIC system turbine trip must be manually reset. All other HPCI and RCIC system operation is automatic. From this point, cooldown would continue with the removal of decay heat using the RCIC system in manual control.

If the RCIC system is unavailable, the relief valve would be used to control reactor depressurization. This is performed by manually opening a relief valve from the main control room. The use of the HPCI system for reactor makeup (either manually or by allowing automatic initiation) would provide additional depressurization of the reactor. After depressurization to 350 psig, the low pressure coolant injection (LPCI) or core spray (CS) systems could also be used for reactor water makeup.

The HPCI and RCIC systems have redundant supplies of water. Normally they take suction from the condensate storage tank (CST). The HPCI system suction will automatically transfer from the CST to the suppression pool if the CST water is depleted or the suppression pool water level increases to a high level. The RCIC system suction must be manually transferred from the CST to the suppression pool using controls located in the main control room. This action would need to be taken when control room alarms indicate CST low water level or suppression pool high water level.

The operator can manually initiate the HPCI and RCIC systems from the control room before automatic initiation from low-low water level is reached.

If both the HPCI and RCIC systems are unavailable, the relief valves would be used to manually depressurize the reactor pressure vessel to less than 350 psig when, in conjunction with a low-low reactor water level of -59 inches, the LPCI and CS systems would be automatically initiated. Once the reactor water level has been recovered and it has been absolutely determined that the LPCI and CS systems are no longer needed, these systems would be manually shut down.

Although the capability of the aforementioned systems to perform as indicated is described during initial operator training and in subsequent retraining, no specific procedure existed which dealt with the loss of feedwater and possible possible unavailability of both the HPCI and RCIC systems.

In its supplemental response dated August 3, 1979, the licensee stated that operating procedures have been revised to specifically instruct operators to manually depressurize the reactor using the relief valves, allowing the LPCI and CS systems to inject water if the normal feedwater, HPCI and RCIC systems are unavailable. All licensed operators have received training in these revised procedures and documentation of this training will be kept on file.

We conclude that the licensee's procedural summary of automatic/manual actions necessary for the proper functioning of auxiliary heat removal systems used when the main feedwater system is inoperable satisfies the intent of IE Bulletin 79-08, Item 3.

4. Describe all uses and types of vessel level indication for both automatic and manual initiation of safety systems. Describe other redundant instrumentation which the operator might have to give the same information

regarding plant status. Instruct operators to utilize other available information to initiate safety systems.

The licensee's response was evaluated to determine that (1) all uses and types of vessel level indication for both automatic and manual initiation of safety systems were addressed, (2) it addressed other instrumentation available to the operator to determine changes in reactor coolant inventory and (3) operators were instructed to utilize other available information to initiate safety systems.

The licensee's response of April 27, 1979 states that vessel level indication for both automatic and manual initiation is achieved by diverse and redundant instrumentation. The vessel level indication is comprised of four types of instruments. Two of the four types, the narrow and wide range Yarway indicators, are used for the manual and/or automatic initiation of the safety systems.

(1) The narrow range Yarway level instrumentation has a range of +60 inches to -60 inches. This covers the normal operating range down to the lower instrument nozzle. Operation of this instrumentation requires no power supply, and it provides most of the trip functions associated with the water level instrumentation. It is referenced to "instrument zero," is calibrated at 1000 psig reactor pressure, and is rapid-pressure-change-compensated. The setpoints and functions of the narrow range Yarway include:

Setpoints	Functions
+48 inches	Trips main turbine, HPCI and RCIC system turbines and main feedwater pumps.
+30 inches	Automatic feedwater runout reset. Inhibits runout flow control above +30 inches. Normal operating level.

+8 inches	Reactor scram. Initiates Groups 2 and 3 containment isolation and control room ventilation isolation.
-59 inches	Initiates ECCS. Initiates RCIC system. Initiates Group 1 containment isolation. Initiates standby diesel-generators. Trips recirculation pumps.

Two narrow range Yarway level indicators are located in the main control room and ten level indicating switches with indicators are located in the reactor building.

(2) The wide range Yarway level instrumentation has a range of 300 inches, covering the active core range and overlapping the lower part of the narrow range Yarway. This provides indication during and after a blowdown accident when the recirculation pumps are tripped. It also signals to prevent the residual heat removal (RHR) system from operating in the containment spray mode when the level is below 2/3 core height. Two wide range Yarway indicators are located in the control room.

In addition to the Yarway level instruments, there are narrow and wide range GE/MAC level instruments which can be used by the operator to monitor vessel water level.

(3) The narrow range GE/MAC level instrumentation is the most accurate level indication available to the operator. It provides the level input to the feedwater level control system. Its range of zero to 60 inches covers the normal operating range. It is calibrated at 1000 psig and is temperature compensated.

The recorder alarms in the control room at high and low water levels. The level indications can also be displayed on the control room digital window display and recorded on the control room computer printout.

(4) The wide range GE/MAC level instrumentation provides level indication during vessel flooding on cooldown. Its range is 400 inches and covers the upper portion of the reactor vessel. One wide range GE/MAC level indicator is located in the main control room. The wide range GE/MAC level indications can also be displayed on the main control room digital window recorded display and on the control room computer printout.

There is also a lower 400 inches vessel level GE/MAC indicator which covers levels below the range of the lower Yarway and overlaps the range of all level instrumentation except the upper wide range GE/MAC.

In addition to the above indications available to the operator, alarms associated with the automatic actions listed above will inform the operator of the reactor vessel level status and require his verification that actions have taken place at the appropriate levels.

As listed in the licensee's supplemental response dated August 3, 1979, the control room operator has numerous alternate indications that can indirectly indicate a change in reactor vessel coolant inventory. Instrumentation is available in the control room to monitor:

Drywell Pressure
Drywell Temperature
Suppression Chamber Pressure
Suppression Chamber Temperature
Suppression Chamber Water Level
Feedwater Flow
Steam Flow
Reactor Pressure
Relief Valve Discharge Temperature
Drywell Floor and Equipment Sump Discharge Flow
Reactor Building Closed Cooling Water Temperature

Any of these measured parameters could indirectly indicate a change in reactor vessel coolant inventory.

The licensee's August 3, 1979 letter states that the operators have been instructed to utilize other available information as part of their training as required by Item 1 of IE Bulletin 79-08. In addition, the use of multiple indications to identify abnormal conditions is an underlying philosophy of the licensee's abnormal and emergency procedures. All licensed operators are trained on these procedures annually as part of their requalification training.

We conclude that the licensee's description of the uses and types of reactor vessel level/inventory instrumentation and instructions to operators regarding the use of this information satisfies the intent of IE Bulletin 79-08, Item 4.

5. Review the actions directed by the operating procedures and training instructions to ensure that:

   a. Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features will result in unsafe plant conditions (e.g., vessel integrity).

   b. Operators are provided additional information and instructions to not rely upon vessel level indication alone for manual actions, but to also examine other plant parameter indications in evaluating plant conditions.

The licensee's response was evaluated to determine that (1) it addressed the matter of operators improperly overriding the automatic actions of engineered safety features, (2) it addressed providing operators with additional information and instructions to not rely upon vessel level indication alone for manual actions and (3) that the review included operating procedures and training instructions.

In its response dated April 27, 1979, the licensee stated that safety systems are to be operated in their normal automatic mode, and that manual control is taken only in extreme cases to prevent unsafe plant conditions, equipment damage, or personnel injury. The standing operating orders and administrative procedures reflect this, and they address other requirements pertaining to instrument indications, administering ECCS, administering the standby liquid control system, operating within safety limits, and departure from approved procedures.

The licensee has advised us that based on the reviews it performed in response to IE Bulletin 79-08, all revisions to the standing operating orders and administrative procedures have been implemented. In addition, the operating procedures associated with reactor water level control and/or ECCS have been reviewed for notes concerning the overriding of engineered safety features and the proper use of level instrumentation for operational decisions.

In its supplemental response dated August 3, 1979, the licensee confirmed that the review of operating procedures and training included verification that operators are directed to use multiple indications in evaluating plant conditions and are not to rely solely on vessel level indication when taking manual actions during transients.

We conclude that the licensee's review of operating procedures and training instructions satisfies the intent of IE Bulletin 79-08, Item 5.

6. Review all safety-related valve positions, positioning requirements and positive controls to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features. Also review related procedures, such as those for maintenance, testing, plant and system start-up, and supervisory periodic (e.g., daily/shift checks) surveillance to ensure that such valves are returned to their correct positions following necessary manipulations and are maintained in their proper positions during all operational modes.

The licensee's response was evaluated to assure that (1) safety-related valve positioning requirements were reviewed for correctness, (2) safety-related valves were verified to be in the correct position and (3) positive controls were in existence to maintain proper valve position during normal operation as well as during surveillance testing and maintenance.

The licensee's response dated April 27, 1979 described the review of safety-related valve positioning requirements and described how safety-related valves are verified to be in the correct positions.

The positions of vital manual ECCS valves are controlled by the use and documentation of locks on the handwheels. Motor-operated valves on safety systems are positioned so as to require minimal automatic valve actions upon system initiation. Moreover, ECCS initiation logic is such that valves may be in off-positions, but will go to their proper positions under initiation conditions. The only valves which do not automatically open if closed are normally open and have key-lock switches in the control room.

Surveillance and testing procedures for safety-related equipment include step-by-step checklists to verify proper lineup of equipment following testing. Each procedure is reviewed by station management as an additional verification of proper return to an operational state.

Additionally, when safety-related equipment is removed from service for maintenance, the equipment outage procedure requires documentation of its proper removal and return to service. Functional tests of the equipment are also required by this procedure when the equipment is placed into operation to ensure operability and proper response of the system.

In its supplemental response dated August 3, 1979, the licensee confirmed that both station personnel and the NRC Region III resident inspector have verified the correct alignment for operation of all accessible valves in the safety systems. Since shortly after the TMI accident, the suction valves to the ECCS pumps have been verified open daily. By a subsequent telephone conversation, the licensee advised us that it has implemented a procedure to verify daily that all accessible ECCS valves in the main flow paths are in their proper positions.

We conclude that the licensee's review of safety-related valve positioning requirements, valve positions and positive controls to maintain proper valve positions satisfies the intent of IE Bulletin 79-08, Item 6.

7. Review your operating modes and procedures for all systems designed to transfer potentially radioactive gases and liquids out of the primary containment to assure that undesired pumping, venting or other release of radioactive liquids and gases will not occur inadvertently.

   In particular, ensure that such an occurrence would not be caused by the resetting of engineered safety features instrumentation. List all such systems and indicate:

   a. Whether interlocks exist to prevent transfer when high radiation indication exists.

   b. Whether such systems are isolated by the containment isolation signal.

   c. The basis on which continued operability of the above features is assured.

The licensee's response was evaluated to determine that (1) it addressed all systems designed to transfer potentially radioactive gases and liquids out of primary containment, (2) inadvertent releases do not occur on resetting engineered safety features instrumentation, (3) it addressed the existence of interlocks, (4) the systems are isolated on the containment isolation signal, (5) the basis for continued operability of the features was addressed and (6) a review of the procedures was performed.

In its April 27, 1979 response, the licensee identified the following lines used to transfer potentially radioactive liquids and gases from the containment:

Drywell floor drain sump discharge
Drywell equipment drain sump discharge
Drywell and suppression chamber ventilation
Torus transfer to condenser hotwell or radwaste

Valves on all the above lines isolate the primary containment during a Group 2 isolation. This isolation is initiated on high drywell pressure (+2 psig) or low reactor water level (+8 inches), both indicating a possible leak to the containment. A seal-in circuit is used to prevent the valves from returning to their original positions upon reset of the initiating instrumentation. A manual reset performed by the operator is needed to return to the original valve lineup. With the isolation signal present, however, no sump discharge or torus water transfer can take place, and gas venting through two-inch valves to the standby gas treatment system can only be done after using a key-lock bypass switch. Procedural controls and annunciator indication govern operation of this bypass feature. No interlocks presently exist to prevent gas or liquid transfer from the containment when a containment high radiation condition exists.

While performing the review of the above isolations, it became evident that upon manual reset of the isolation, after isolation initiation conditions have cleared, open paths to the containment could exist. This is exemplified by the drywell sump discharge line valves. Upon isolation reset, these valves will reopen and the sump pumps will start on high sump level, pumping potentially high activity material from the containment. At the present time, these valves are maintained in the closed position and opened only during the periodic pumping down of the sumps to radwaste. This practice will be continued, along with procedural controls to close these valves and leave them closed after a Group 2 isolation. They will not be opened until containment atmosphere and reactor coolant samples can be taken to insure that high activity materials have not been released to the containment.

The drywell and torus ventilation valves would respond in a similar manner. If a purge of the drywell were in progress at the time a Group 2 isolation occurred, the valves on the vent lines would return to the open position, opening a path out of the containment upon reset of the isolation. The licensee has instituted procedural controls which specify that the Group 2 isolation valves be placed in the closed position before a manual reset is attempted.

In summary, isolations of lines which transfer radioactive materials from the primary containment do exist. These isolations do not automatically reset by the reset of the initiation instrumentation only, but also require a manual reset. This logic provides a means of controlling releases. The isolations are also tested according to the Technical Specifications to assure operability.

In its supplemental response dated August 3, 1979, the licensee stated that the procedure changes discussed above have been initiated. By a subsequent telephone conversation, the licensee advised us that these procedure changes have been completed.

We conclude that the licensee's review of systems designed to transfer radioactive gases and liquids out of primary containment to assure that undesired pumping, venting, or other release of radioactive liquids and gases will not occur, satisfies the intent of IE Bulletin 79-08, Item 7.

8. Review and modify as necessary your maintenance and test procedures to ensure that they require:

   a. Verification, by test or inspection, of the operability of redundant safety-related systems prior to the removal of any safety-related system from service.

   b. Verification of the operability of safety-related systems when they are returned to service following maintenance or testing.

   c. Explicit notification of involved reactor operational personnel whenever a safety-related system is removed from and returned to service.

The licensee's response was evaluated to determine that operability of redundant safety-related systems is verified prior to the removal of any safety-related system from service. Where operability verification appeared only to rely on previous surveillance testing within Technical Specification intervals, we asked that operability be further verified by at least a visual check of the system status to the extent practicable, prior to removing the redundant equipment from service. The response was also evaluated to assure that provisions were adequate to verify operability of safety-related systems when they are returned to service following maintenance or testing. We also checked to see that all involved reactor operational personnel in the oncoming shift are explicitly notified during shift turnover about the status of systems removed from or returned to service since their previous shift.

In its April 27, 1979 response, the licensee stated that existing procedures require that redundant and required backup systems are functionally tested prior to removal of safety-related equipment from service for planned maintenance or testing. This practice includes testing of each subsystem and backup system prior to removal of the equipment from service and testing thereafter in accordance with the Technical Specifications until such equipment is returned to an operational status.

Safety-related equipment maintenance or testing procedures also require system functional tests to verify operability when equipment is returned to service. These tests verify proper operation through all isolation points required for its removal from service.

Surveillance procedures or maintenance work packages which require safety-related equipment outages require a shift supervisor's approval prior to removing equipment from service. This approval is given after proper testing or verification of redundant equipment is performed. When the equipment is returned to service, these packages or procedures again require a shift supervisor's notification for review and testing prior to declaring the component operable.

In its supplemental response dated August 3, 1979, the licensee stated that Procedure QAP 300-4, "Shift Change for Nuclear Station Operators," describes those actions to be taken upon shift turnover. Included in these actions is the review of the shift log by the incoming operator for equipment taken out of service. Other actions are verbally transferred at shift change, such as special conditions, current operational status, and useful information for future shifts. The incoming operator, by this procedure, is required to check control room panels for proper system lineups.

We conclude that the licensee's review and modification of maintenance, test and administrative procedures to assure the availability of safety-related systems and operational personnel knowledge of system status satisfies the intent of IE Bulletin 79-08, Item 8.

9. Review your prompt reporting procedures for NRC notification to assure that NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time an open continuous communication channel shall be established and maintained with NRC.

The licensee's response was evaluated to determine that (1) prompt reporting procedures required or were to be modified to require that the NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation and (2) procedures required or were to be modified to require the establishment and maintenance of an open continuous communication channel with the NRC following such events.

In its April 27, 1979 response, the licensee stated that the existing Generating Stations Emergency Plan requires procedures for notification of the NRC as well as other regulatory agencies in the event of an emergency situation such as described in this item. In such an event, the shift engineer will immediately notify the system load dispatcher, who in turn will notify the command center director on duty, who will place an immediate call to the NRC. In the event that the load dispatcher cannot reach the duty command center director within five minutes, the load dispatcher will then notify the NRC.

The command center procedure requires that specific telephones be designated as open lines in which continuous communications could be established.

Based on the licensee's review of the existing Generating Stations Emergency Plan and its implementing procedures, the licensee believes that notification of the NRC within one hour and maintenance of an open line of communication are assured should the conditions specified ever exist.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 9.

10. Review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident that would either remain inside the primary system or be released to the containment.

The licensee's response was evaluated to determine if it described the means or systems available to remove hydrogen from the primary system as well as the treatment and control of hydrogen in the containment.

In its response dated April 27, 1979, the licensee stated that it had reviewed the operating modes and procedures dealing with the generation of hydrogen gas either in the primary system or released to the containment during a transient.

The reactor head is continuously vented to the "A" main steam line and, therefore, any hydrogen gas generated during a transient could be released to the containment via the "A" main steam line relief valve, which relieves directly to the suppression pool. In addition, the reactor head can also be vented directly to the containment by means of two vent valves, which are remotely operated from the main control room. However, these valves are not normally opened without first depressurizing the system.

The hydrogen gas released to the containment is controlled by means of the containment nitrogen inerting system. The containment atmosphere oxygen concentration can be reduced to less than five percent with nitrogen gas within a 24-hour period, subsequent to placing the reactor mode switch in the "run" position following a shutdown. The five percent oxygen concentration minimizes the possibility of hydrogen combustion following a loss-of-coolant accident.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 10.

11. Propose changes, as required, to those technical specifications which must be modified as a result of your implementing the items above.

The licensee's response was evaluated to determine that a review of the Technical Specifications had been made to determine if any changes were required as a result of implementing Items 1 through 10 of IE Bulletin 79-08.

In its letter dated April 27, 1979, the licensee reported that, based on its review and investigative program performed in response to Items 1 through 10 of IE Bulletin 79-08, no modifications to the Technical Specifications for Quad Cities 1 and 2 are appropriate, so none were proposed.

We conclude that the licensee's response satisfies the intent of IE Bulletin 79-08, Item 11.

Conclusion

Based on our review of the information provided by the licensee to date, we conclude that the licensee has correctly interpreted IE Bulletin 79-08. The actions taken demonstrate the licensee's understanding of the concerns arising from the TMI-2 accident in reviewing their implementation on Quad Cities 1 and 2 operations, and provide added assurance for the protection of the public health and safety during the operation of Quad Cities Station, Units 1 and 2.

References

1. IE Bulletin 79-05, dated April 1, 1979.

2. IE Bulletin 79-05A, dated April 5, 1979.

3. IE Bulletin 79-08, dated April 14, 1979.

4. CECo letter, C. Reed to J. Keppler, dated April 27, 1979.

5. NRC staff letter, T. Ippolito to C. Reed, dated July 20, 1979.

6. CECo letter, C. Reed to T. Ippolito, dated August 3, 1979.