UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
LONG ISLAND LIGHTING COMPANY	)	Docket No. 50-322 O.L.
(Shoreham Nuclear Power Station, Unit 1)	)	

COMBINED DIRECT TESTIMONY OF MARC W. GOLDSMITH

AND GREGORY C. MINOR ON BEHALF OF SUFFOLK COUNTY REGARDING

SUFFOLK COUNTY CONTENTION NO. 3 AND SOC CONTENTION 8

DETECTION OF INADEQUATE CORE COOLING

May 25, 1982

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Summary Outline of Suffolk County Contention 3
and Shoreham Opponents Coalition Contention 8 Testimony*

Suffolk County contends that LILCO and the NRC Staff have not demonstrated and confirmed that Shoreham has adequate instrumentation and procedures to detect and monitor the onset of inadequate core cooling (ICC). LILCO has thus failed to comply with applicable regulatory requirements.

The testimony demonstrates the inadequacy of Shoreham's current water level instrumentation method to detect ICC as a result of the problems and potential errors associated with that system. The testimony makes recommendations as to needed improvements in Shoreham's design and instrumentation to detect and monitor the onset of ICC, and outlines the value of supplementing existing instrumentation with in-core thermocouples to provide improved more direct measurement of the onset of ICC.

The GE/LILCO position opposing the installation of additional instruments to detect ICC is discussed. The NRC's position under NUREG-0737 and Regulatory Guide 1.97 Revision 2 is also discussed.

LILCO should be required to comply with existing NRC regulations and provide additional instrumentation (such as in-core thermocouples) to supplement current water level instrumentation to provide an improved direct measurement of (the onset of) ICC.

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*/ ASLB Memorandum and Order, March 15, 1982.

<u>Attachments*</u>

1. SER Open Item #44 - Level Measurement Error (SNRC-614) SNPS-1 FSAR (3/29/82).

2. Board Notification - Errors in BWR Vessel Water Level Indication (BN-82-08) w/attachments (Feb. 9, 1982).

3. "Safety Concern Associated with Reactor Vessel Level Instrumentation in Boiling Water Reactors" from C. Michelson, NRC Office for Analysis and Evaluation of Operational Data to H. Denton, NRR (January 20, 1982).

4. SP29.023.02, Common Level Control

5. SP29.023.04, Level Restoration

6. SP29.023.09, Reactor Pressure Vessel Flodding

7. NRC Letter, Eisenhut to Denton, (September 11, 1981).

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*/ ASLB Memorandum and Order, March 15, 1982.

Direct Testimony of Marc W. Goldsmith and Gregory C. Minor
Regarding Suffolk County Contention 3 and SOC Contention 8
Detection of Inadequate Core Cooling

Q. Please state your name, address, occupation and qualifications.

A. My name is Marc W. Goldsmith, and my business address is 400-1 Totten Pond Road, Waltham, Massachusetts. I am President of Energy Research Group, Inc. My name is Gregory C. Minor, and my business address is 1723 Hamilton Avenue, San Jose, California. I am Vice President of MHB Technical Associates. Our qualifications have been submitted to this Board separately.**/

Q. Would you please state the contention on which you are testifying?

A. This testimony addresses S.C. Contention 3 and the nearly identical SOC Contention 8. S.C. Contention 3 provides:

> Suffolk County contends that LILCO and the NRC Staff have not demonstrated and confirmed that Shoreham has adequate instrumentation and procedures to detect and monitor the onset of inadequate core cooling (ICC). NUREG-0737, item II.F.2 requires that instrumentation provide an unambiguous, easy-to-interpret indication of inadequate core cooling. LILCO has taken the position that no additional instruments are needed and that current water level instruments are sufficient. But these instruments are not a direct indication of core cooling and core temperature (as are in-core thermocouples) and thus may not provide an unambiguous, easy-to-interpret indication of ICC or fuel failure under certain conditions. There is insufficient diversity of instrumentation to assure that a common event (e.g., drywell high temperature interfering with water level measurement) cannot cause a loss of direct measurement capability. Because there is no direct fuel temperature measurement and because other instruments (e.g., fission product detectors, steam line radiation monitors and hydrogen

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**/ This testimony was prepared under the overall supervision of Marc W. Goldsmith. Mr. Minor was primary author for answers on pages 9 and 10.

monitors) become inoperative under some accident conditions, there is no assurance of indication of the onset of ICC. Therefore, LILCO's design and instrumentation are inadequate to detect and monitor the onset of ICC and do not comply with 10 CFR 50, Appendix A, GDC 13, and 10 CFR 50.55a(h).

Q. What is the purpose of the testimony?

A. The purpose of the testimony is to discuss concerns as to the adequacy of instrumentation and procedures at Shoreham to detect and monitor the onset of Inadequate Core Cooling (ICC). It discusses the inadequacy of Shoreham's current water level instrumentation and outlines the need to supplement the current instrumentation with additional instrumentation (i.e., in-core thermocouples) which will provide an improved more direct measurement of the onset of ICC.

Q. What causes inadequate core cooling?

A. Inadequate core cooling of the nuclear fuel can result from numerous initiating events and failures. The prime initiating events and failures are:

- o a loss-of-coolant accident - depending on the size of the pipe break, the loss of reactor water may be exceptionally rapid (large break) or very slow (small break); and,
- o coolant flow blockage: flow blockage could occur due to a control rod drop causing fuel cladding failures or from a mechanical failure causing a localized channel blockage within the fuel.

In addition to the above, some other examples are, an ATWS event, stuck open primary system valves, and feedwater pump failures, all in conjunction with ECCS problems or allowable failures (e.g., technical specification allowing degraded status).

Q. What are the results of inadequate core cooling?

A. The initiating events discussed in the previous question coupled with failures in ECC systems, could result in a loss-of-coolant from the reactor core. Failures to implement corrective actions either by lacking the appropriate equipment, receiving the wrong information from inaccurate instruments, or following a procedure incorrectly could lead to ICC. The result of ICC could be failure of the cladding, releasing radioactive gases to the primary, followed by fuel melting (core melt), which in turn may lead to subsequent failures in the reactor pressure vessel or primary piping followed by the release of radiation.

Q. Is it important to detect inadequate core cooling early?

A. Yes. Early detection will minimize the maximum temperature approached by the fuel and cladding by flooding the vessel, shutting the chain reaction and increasing the coolant flow rates.

Q. What methods are used at Shoreham to detect ICC?

A. Shoreham uses only a water level measurement technique for ICC detection. The direct means of detecting ICC is to measure the temperature of the fuel cladding. There are also two measurement techniques which provide a direct implication of ICC: (i) measuring the water level in the reactor vessel to determine if the coolant level is higher than the top of the active fuel and (ii) measurement of coolant temperature in the region of the fuel (e.g., thermocouples in or near the core). At Shoreham, water level indication systems are used as the most direct measure of core cooling. The Shoreham reactor uses an uncompensated reference leg indication, known as the cold leg or GEMAC, to indicate water level within the vessel. Several independent GEMAC's are used. A GEMAC system consists of a reference leg and a variable leg connected through a differential pressure transmitter to numerous level indicating, level transmitting, and flow controllers. There are two narrow range redundant reference leg instrumentation systems for Shoreham. In addition, there is also a wide range level instrumentation system. An explanation of the operation of Shoreham's water level instrumentation is contained in Attachment 1. Currently at Shoreham the operator receives his core cooling measurement information through interpretation of water level instrumentation described in Attachment 1.[1/] This instrumentation relies basically on the same principles for both narrow range and wide range level detection. As shown in Attachments 2[2/] and 3,[3/] there are numerous potential mechanisms for failure of the water level instrumentation. There is also the potential for a single event to interfere with all water level measurement. In addition, because of potential control-protection system interaction some water level system failures could send misleading information. Therefore, current water level measurement instrumentation in my opinion does not have sufficient reliability to keep the operator informed of the water level or the on-set of ICC.

There are at Shoreham several indirect core cooling measurements that an operator may use to supplement the direct water level measurement. These are fission product monitoring at the off-gas ejector, pump pressures and flow rates, steam flow, temperatures, neutron flux monitoring, and system performance. Most of these

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1/ SER Open Item #44 - Level Measurement Error (SNRC-614) SNPS-1 FSAR (3/29/82).

2/ Board Notification - Errors in BWR Vessel Water Level Indication (BN-82-08) w/attachments (Feb. 9, 1982).

3/ "Safety Concern Associated with Reactor Vessel Level Instrumentation in Boiling Water Reactors" from C. Michelson, NRC Office for Analysis and Evaluation of Operational Data to H. Denton, NRR (January 20, 1982).

measurements would be lost to the operator in the event of a containment isolation. An event that would cause containment isolation would also scram the reactor and would isolate the reactor pressure vessel from normal routes of core cooling and steam flow. The fission product route to the off gas ejector would be closed, feedwater and main steam flow would be shut and neutron flux would go down to the source range or shutdown flux range. Therefore, in the event of a containment isolation, these measurements would be unavailable to the operator. Therefore, the operator would have to rely primarily on water level detection through water level instrumentation systems.

Q. Are there any other available methods to detect ICC which are not used at Shoreham?

A. Yes, in-core and core exit thermocouples would provide more direct coolant measurement and a continuous fission product monitoring system is another both method that could be used at Shoreham to provide a diverse means of detection of inadequate core cooling.

In-core or core exit thermocouples could be placed within the coolant flow using existing instrument thimbles that lead through the reactor core for other instrumentation. These thermocouples placed near the top of the reactor core or somewhat above it would see temperature rises as the core water level decreased and would begin to indicate the onset of inadequate core cooling. As these thermocouples would be regionally placed within different quadrants of the core, they may also provide indicators of localized coolant flow blockage as they would measure coolant temperature near the outlet of the fuel. If the temperature of the in-core/core exit thermocouples was to begin to rise with little or no change in water level, then the operator would be alerted to a potential problem. In addition, if the two independent water level indicating systems (e.g. System A and System B of the cold reference leg type at Shoreham) were to give different indications of water level, the core thermocouples would provide information as to which is the correct one and allow the operator to take appropriate action early in the process possibly preventing the onset of inadequate core cooling.

Q. Why is another direct method to determine inadequate core cooling necessary at Shoreham?

A. Shoreham's method of detecting water level could result in false level indications (i.e. delayed detection of onset of ICC) to not only the operator but also to automatic emergency core cooling equipment as well. Shoreham's vessel level instrumentation is susceptible to reference leg flashing and consequently loss of accurate level indication. One method of losing accurate water level indication would be a rapid vessel depressurization in conjunctio [illegible] a hotter-than-average containment environment. In addition, as enumerated in Attachment 3, there are several mechanisms by which water level instrumentation has failed in other plants causing a control and indication interaction which has the potential to mislead both the operator and the automatic equipment as to the actual water level. The need for diversity and reliability in water level instrumentation is demonstrated by the following:

1. There is no assurance that a common event cannot cause a loss of accurate level measurement capability (see Attachment 2).

2. A failure in a water level instrumentation line (e.g., an equalizing valve leak, excess flow check valve leak, drain valve leak, etc.) could cause an inaccurate reference leg level. These examples could cause a reference leg level decrease which "would cause all the differential pressure instruments connected to that line to indicate false high reactor vessel water level." (See Attachment 3). In a water

level instrument system transient, both high and low level water alarms could be activated in the control room. Depending on which indicator the control room operator chooses to respond to, erroneous actions could result. Because of the potential for conflicting indications and automatic actions as a result of the control and indication interaction, both operator response and automatic plant response could be hampered in such an event. "Automatic plant response must be relied upon to terminate and control the transient. This is confirmed by operating experience which shows several cases where operators did not respond to such events and automatic protective action was needed to terminate the transient." (See Attachment 3).

Q. What has been done about the previously discussed water level instrumentation problems?

A. In order to deal with the ambiguity that may exist as a result of the different failures of water level instrumentation, the BWR Owner's Group[4/] has responded with emergency procedure guidelines. These guidelines have been specifically adopted at Shoreham and are reflected in Shoreham's Emergency Procedures, specifically procedures SP29.023.01, Common Level Control, SP29.023.04, Level Restoration, and SP29.023.09, Reactor Pressure Vessel Flooding. These procedures are attached as Attachments 4, 5, and 6.[5/] These procedures are complicated and could

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4/ "General Electric Evaluation of the Need for BWR Core Thermocouples", General Electric Co., 1981.

5/ Shoreham Emergency Procedures: SP29.023.01, Common Level Control; SP29.023.04, Level Restoration; SP29.023.09, Reactor Pressure Vessel Flooding.

therefore add to confusion during an event that may lead to inadequate core cooling. For example, procedure SP29.023.01 requires the operator to restore and maintain the reactor pressure vessel water level between 12.5 in. and 54.5 in. This procedure makes no indication until one gets to step 3.4 as to whether water level can be determined and makes no indication as to whether the water level system may or may not be accurate. How to check water level is not made clear. Therefore, this procedure could lead to ICC by not providing a caution or an indicator that under certain conditions it may be possible that the water level indicator is inaccurate.

Very heavy reliance is placed on the water level measurement system by both the procedures and the operator during operation. Procedures continually direct the operator to confirm or verify water level (see e.g. SP29.010.01, Emergency Shutdown). Therefore, it is important for the operator to have a high degree of confidence in the instrumentation and for the instruments to be reliable.

Q. In your technical opinion, are NRC regulations and regulatory guidance violated by using Shoreham's current methods to detect ICC?

A. Several General Design Criteria are violated by the current water level instrumentation and by the potential for lack of detection of ICC. General Design Criteria 13, 24 and 35 are violated by the current water level instrument design and it is possible that 10 CFR 50.55a(h) may also be violated. In addition, it may be possible to violate the emergency core cooling limits on maximum cladding temperature (2200^{o}F) contained in 10 CFR 50.46 by a failure to initiate emergency core cooling systems in a timely manner that would prevent exceeding the limit.

General Design Criterion 13 of 10 CFR 50 Appendix A, states:

> "Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges."

The methods employed at Shoreham to detect ICC could provide erroneous water level indications which would result in ICC. Therefore, appropriate controls to maintain variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, the containment and its associated systems within prescribed operating ranges are not provided at Shoreham.

10 CFR 50.55a(h) states:

> "For construction permits issued after January 1, 1971, protection systems shall meet the requirements set forth in editions or revisions of the Institute of Electrical and Electronics Engineers Standard: 'Criteria for Protection Systems for Nuclear Power Generating Stations.' (IEEE-279) in effect on the formal docket date of the application for a construction permit. Protection systems may meet the requirements set forth in subsequent editions or revisions of IEEE-279 which become effective."

LILCO has not demonstrated that Shoreham's method of detecting ICC meets the requirements set forth in editions or revisions of the IEEE "Criteria for Protection Systems for Nuclear Power Generating Stations (IEEE-279). Thus, LILCO has not demonstrated that it can assure the independence of the vessel level sensors necessary to prevent control/safety interaction as required by IEEE-279 Section

4.7. In fact, there is indication that the instrument lines of the level system do not meet IEEE-279 (see Attachment 7).[6/] Further, there is evidence that single failure criteria of IEEE-279 Section 4.73 and 4.74 are not complied with in the vessel level instrumentation[7/] which would be inputs to the Reactor Protection System and to Inadequate Core Cooling indication. Therefore, 10 CFR 50.55a(h) is not met.

General Design Criterion 24 of 10 CFR 50, Appendix A, "Separation of Protection and Control Systems" states:

> "The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired."

In the BWR water level instrumentation system, a single failure in the sensing line that serves both protection and control systems that can cause control system action, does not leave intact a system satisfying all reliability, redundancy and independence requirements for the low vessel level protective function. Thus Shoreham's water level detection system does not meet this GDC.

10 CFR 50, Appendix A, General Design Criterion 35, "Emergency Core Cooling" states:

> "a system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

6/ NRC ltr/Eisenhut to Denton, September 11, 1981, Attachment 7).

7/ See discussion above, plus Suffolk County Testimony on 7B).

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure."

Because a single failure may cause loss of the safety function of the ECCS as stated above under GDC 24, Shoreham also fails to meet this criterion.

Q. Has the post-TMI experience, as discussed in NUREG-0737 and Regulatory Guide 1.97, been satisfactorily answered by LILCO?

A. No. The TMI Action Plan requirements contained in NUREG-0737, "Clarification of TMI Action Plan Requirements" at II.F.2, "Instrumentation for Detection of Inadequate Core Cooling," may not be met. This item states that indication of ICC must be unambiguous and easy-to-interpret. NUREG-0737 states that water level instruments could be supplemented for this purpose by additional instrumentation such as in-core thermocouples. Because Shoreham instrumentation could be ambiguous or misleading, it is necessary to supplement the existing water-level instruments. Because of the potential for misleading information, Shoreham does not comply with this NUREG-0737 requirement.

Further, Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2 (December 1980), states:

> "Tables 1 and 2 of this regulatory guide should be considered as the <u>minimum</u> number of instruments and their respective ranges for accident-monitoring instrumentation for each nuclear power plant." [Emphasis added].

Table 1, "BWR variables", provides for core thermocouples to monitor core cooling and indicate the potential for breaching, or the actual breach of, fuel cladding. The guide states that four thermocouples should be provided for each quadrant and that a minimum of one measurement per quadrant is required for operation. The guide requires installation of core thermocouples on the following schedule;

> ". . .plants scheduled to be licensed to operate before June 1, 1983, should meet the requirements of NUREG-0737 and the Commission Memorandum and Order (CLI-80-21) and the schedules of these documents or prior to the issuance of a license to operate, whichever date is later. The balance of the provisions of this guide should be completed by June 1983."

LILCO's commitment consists solely of implementing the generic resolution of this issue between the BWR Owner's Group and the NRC. Neither the time for implementation nor any Shoreham specifics to meet the thermocouple requirements are detailed in the FSAR.[8/] Indeed, since there is no such resolution at this time, there is no means to judge the adequacy of LILCO's position. In our view, LILCO has failed to demonstrate compliance with regulatory requirements.

Q. What is recommended to improve Shoreham's design and instrumentation to detect and monitor the onset of ICC?

A. There are several systems and or components that could supplement Shoreham's current water level detection instrumentation. The system providing more direct measurement of in-core coolant temperatures and the potential for ICC in my opinion are in-core and core exit thermocouples.

8/ II.F.2 "Identification of and Recovery From Conditions Leading to Inadequate Core Cooling." Shoreham FSAR Vol. 16, Rev. 22 - July 1981.

In-core and core exit thermocouples provide several advantages when supplementing current water level instrumentation. These are:

1. Events that can cause a loss of direct water level measurement capability (e.g., drywell high temperature interfering with water level measurement) would not affect the in-core thermocouples in the same manner. In-core thermocouples can provide an improved indication of ICC, either confirming or disputing current water level measurements, since thermocouples would not give erroneous indication of ICC under the same conditions that would cause water level systems to give erroneous indication.

2. Water level measurement systems indicate a reduction in the reactor water level. However, there are many transients which usually result in this level reduction, such as main steam isolation valve (MSIV) closure, steam line break, LOCA, loss of feedwater, etc. that may not result in ICC. In-core thermocouples would confirm adequate cooling under most conditions (an exception being during the use of core spray). During core spray the thermocouples would probably read core spray water temperature and not bulk coolant temperature.

3. In-core thermocouples can serve to detect local flow blockage and inadequate core spray distribution[9/] which would not be possible with water level indication alone. There have been some cases of localized flow blockage in nuclear power plants. The use of in-core thermocouples could, depending on the number and location, provide an indicator of regions or

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9/ "Board Notification - Japanese Core Spray Distribution Tests On a Simulator BWR/5 Configuration" (BN-81-49) from R.I. Tedesco, NRC Division of Licensing to ASLB for the Shoreham NPS (12/11/81).

areas of the core where the coolant temperature is higher than would be normally expected and could indicate localized flow blockage. In addition, the use of in-core thermocouples might potentially indicate inadequate core spray distribution such that it may allow the operator to use other means of providing core cooling. Use of water level detection alone would not indicate regional or spacial variations within the core which may become apparent through the use of localized or regionally placed thermocouples.

In addition, several indirect methods exist that might provide the operator with information relative to the onset of ICC. These methods are less preferable than the more direct method of in-core thermocouples. These methods in my opinion have limitations in detecting ICC. These are:

1) The use of a continuous reactor coolant water bleed to measure fission product levels within the reactor coolant water under all conditions. This system would have to remain in operation during containment isolation so that a continuous reading of fission product levels could be obtained. This would detect cladding failure and fuel melt, but may not give much advance warning.

2) The use of steam area thermocouples in conjunction with pressure measurement to determine whether saturated steam or superheated steam is exiting from the core region. If super heated steam was detected, that would indicate uncovery of the fuel in the active region of the core.

3) Additional neutron flux monitoring with finer resolution to better determine water level changes using neutron flux measurements in the core. It appears that the neutron flux monitoring for full core uncovering would be clear and

unambigious. For partial core uncovering thermal neutron flux might show a drop off. Thus there would be a significant uncertainty for its use as a level measurement.[10/]

Q. Will in-core thermocouples improve the operator's diagnostic capabilities?

A. Yes. Recent events in operating plants have shown that the ability of the reactor operator to successfully respond to accident conditions is highly sensitive to the quality of information he can obtain and process concerning the state of the plant. This information can only be provided to the operator by the plant instrumentation. It is most useful, if it is a direct reliable and accurate indicator of the variable to be used. The closer the measurement of the specific variable to be used usually, the smaller and fewer the number of potential errors that might exist in the indicator, instrument or control that displays that variable. Errors in instrumentation and measuring of parameters can be cumulative. Therefore, the further away from the actual parameter to be measured the greater the potential for error in accurately representing the specific variable.

The operator's capability to both diagnose and respond to inadequate core cooling will be greatly improved by information that will be available to him through the use of in-core thermocouples. This information, used in conjunction with the current water level instruments, can provide better insight into total core cooling and can better detect localized blockage or region specific problems.

10/ General Electric, "A Prepublication Version of Section 3.5.2.3 of NEDO-24708, Diverse Methods of Detecting Core Cooling".

Q. What is LILCO's position on installing additional core-cooling instruments (specifically, in-core thermocouples)?

A. LILCO and General Electric, as the prime supplier, have taken the position that, "BWR's do not need in-core thermocouples for any purpose."[4/] "In the BWR, water level is the primar measure of accomplishment of core cooling during accident situations. . .These systems (reactor water level measurement) are adequate and sufficient to reliably monitor water level during all inventory threatening events.[4/]

However, General Electric recognized, in its emergency operating guidelines,[2/] that flashing in the cold reference leg level instrument lines can occur, which represents a source of error in level indication. But, according to G.E.[1/] "even if flashing/boil-off were to occur, it would not be a concern if the operator follows the emergency procedure guidelines (EPG) and maintains reactor level in the normal water level range." In addition, G.E. states that the error due to flashing/boil-off would be eliminated if the operator takes corrective actions.[1/] Reliable or accurate indication of a parameter is important to an operator. If the information received by the operator is inaccurate, unreliable, or untrustworthy then the operator would be forced to go to another source for that information or to take some form of action which may not be correct. Operator response is in part based on his level of trust in a particular indicator or instrumentation. If the operator does not have confirming or comparative instrumentation for a particularly important parameter, it is difficult for the operator to detect errors and take corrective action. Instrumentation that may be unreliable should either be corrected, less reliance placed on the instrumentation, or other instrumentation that would provide increased reliability or confirmation of the accuracy of the information should be provided. However, in the case of water level instrumentation, comparative information, through some independent or diverse technique is not provided at Shoreham. Rather than correcting this problem by providing additional information, G.E. appears to place the burden of detecting inadequate core cooling on the operator when, in fact, the operator cannot take adequate corrective action unless proper instrumentation is available to provide core cooling measurements.

General Electric has been aware for several years of the problems related to the potential for false level indication. In fact, in September 1980, General Electric again notified its customers of the importance of compensating for these false level indications in cold reference leg instruments caused by flashing in the sensing lines.[2/] The result of the recognition of this false level indication has continued to be procedural fixes and not the provision of either additional indicators using diverse or more reliable methods and/or improving the reliability of the cold reference leg instrument.

Q. What is the NRC's position on installing additional instruments (i.e. in-core thermocouples)?

A. NRC suggested (NUREG-0737) how the water-level instruments could be used in conjunction with in-core thermocouples. For example, water-level instrumentation may be chosen to provide advanced warning of two-phase level drop to the top of the core and could be supplemented by other indicators such as incore and core-exit thermocouples provided that the indicated temperatures are correlated to provide indication of the existence of ICC and to infer the extent of core uncovery. Alternatively, NRC (NUREG-0737) pointed out that full-range level instrumentation may be employed in conjunction with other diverse indicators such as core-exit thermocouples to preclude misinterpretation due to any inherent deficiencies or inaccuracies in the measurement system selected.

Q. Do any other reactor systems use in-core thermocouples?

A. Yes. In-core thermocouples are used in Westinghouse,[11/] and Combustion Engineering Pressurized Water Reactors.[12/] Combustion Engineering recommends that the thermocouples be located within each neutron sensor, with the grounded junction located approximately 18 inches above the top of the active fuel.[13/] These in-core thermocouples (chromel-alumel type)[14/] provide information on the fuel assembly outlet temperatures at selected locations. From this information, core coolant temperature distribution can be determined.

The number of thermocouples installed is dependent on the reactor power (e.g., the number of thermocouples would be about 61 for 1300 Mwe reactor core - System 80).[12/] In-core thermocouples have been in use for many years and will not add significant new failure modes or mechanisms within the reactor core.

Q. What would satisfy the concerns relative to detecting inadequate core cooling at Shoreham?

A. The major concern is that the operator at Shoreham Nuclear Power Station has the potential to lose accurate water level indication and therefore lose early detection of inadequate core cooling. This concern is currently addressed by the use of complex procedures. Use of procedures to compensate for hardware insufficiencies is inadequate. It is inadequate because the operator does not have alternate methods using diverse instrumentation to ascertain that the water level instrumentation is accurate. The installation of in-core

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11/ Summary Description of Westinghouse Pressurized Water Reactor Nuclear Steam Supply System, Section 14, pp. 14.1-14.5

12/ System 80, Nuclear Steam Supply System, Combustion Engineering, Inc., Section 7.1.

13/ Inadequate Core Cooling Instrumentation, L.A. Banda, of Combustion Engineering, 1981.

14/ Chromel-alumel thermocouples may perform better than other types under high radiation fields.

thermocouples as articulated in Item II.F.2 of NUREG-0737 and in NRC Regulatory Guide 1.97 Revision 2 could provide the necessary supplement to assure the operator that water level was changing or that instrumentation protecting the core from ICC was in fact accurate. The major concern could be satisfied through the use of in-core and exit-core thermocouples or through the use of another indicator that would provide as directly as possible to the operator knowledge of the approach of ICC. Until current water level indicators are supplemented by diverse means, LILCO wili not have complied with NRC Requirements.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

DOCKETED USNRC

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

'82 MAY 26 A10:41

OFFICE OF SECRETARY DOCKETING & SERVICE BRANCH

In the Matter of LONG ISLAND LIGHTING COMPANY (Shoreham Nuclear Power Station, Unit 1)	Docket No. 50-322 (OL)

CERTIFICATE OF SERVICE

I hereby certify that copies of the Suffolk County testimony on SC 3 (SOC 8), SC 18, SC 19, SC 21, SC 22, SC 27 (SOC 3), SC 28(a)(iv) (SOC 7.A(4)) and the qualifications of Messrs. Ball, Crosse, and Mazour were served to the following by U.S. Mail, first class, on May 25, 1982, except as otherwise noted.

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May 25, 1982

(*) By hand

ATTACHMENT 1

SER Open Item #44 - Level Measurement Error
(SNRC-614) SNPS-1 FSAR (3/29/82)

SER OPEN ITEM #44 - LEVEL MEASUREMENT ERROR

Review of Reactor Water Level Measurement Instrumentation:

The cold reference leg reactor water level measurement design for Shoreham is illustrated in Figure 1. Reactor vessel water level is measured by differential pressure transmitters which measure the difference in static head between two columns of water. One column is a "cold" (ambient temperature) reference leg outside the reactor vessel; the other is the reactor water inside the reactor vessel. The measured differential pressure is a function of reactor water level.

The cold reference leg is filled and maintained full of condensate by a condensing chamber at its top which continuously condenses reactor steam and drains excess condensate back to the reactor vessel through the upper level tap connection to the condensing chamber. The upper vessel level tap connection is located in the steam zone above the normal water level inside the vessel. Thus, the reference leg presents a constant reference static head of water to the high pressure tap on the d/p transmitter. The low-pressure tap of the transmitter is piped to a lower-level tap on the reactor vessel which is located in the water zone below the normal water level in the vessel. The low-pressure side of the transmitter thus senses the static head of water/steam inside the vessel above the lower vessel level tap. This head varies as a function of reactor water level above the tap and is the "variable leg" in the differential pressure measured by the transmitter. Lower taps for various instruments are located at various levels in the vessel water zone to accommodate both narrow- and wide-range level measurements (see Figure 2).

Typical reactor level indicators and recorders are shown on Figure 3. This figure also shows the condensing chamber. Shoreham level instrumentation, including elevations and set points, is shown in Figure 4.

Problem Description:

Small (e.g., .01 ft^2) and intermediate (e.g., .04 ft^2) break accidents (LOCA's) that discharge steam into the drywell (at temperatures as high as 340°F) for an extended time period result in substantial heat-up of components/air in the drywell (including reactor water level sensing lines). If the reactor is subsequently depressurized below 118 psia, water in the reactor water level sensing lines located in the drywell will flash.

General Electric has conservatively evaluated many steam break accidents and has determined that, for the worst case scenario (small break accident with ADS operation after 1800 seconds), flashing will result in a loss of up to 20% of the water in the sensing lines. Water in the variable leg sensing line will be replenished by drain back from the reactor, while water in the reference leg sensing line will continue to be gradually depleted due to boil-off. If no operator action is taken, all of this water could, for the worst case, boil off after more than 10 hours after the accident. Loss of water from the reference leg results in a sensed reactor water level that is higher than the actual reactor water level. Shoreham reactor water level instrumentation utilizes two reference legs for the narrow and wide-range level instrumentaiton. Utilizing instrumentation keyed to the longer leg (worst case), a level error of approximately 9.1' could occur. It should be noted that all reactor water level activated safety trips will occur since they would initiate before the reactor is depressurized below 118 psia.

Operator Actions and Conditions that Prevent and/or Eliminate Flashing/Boil-Off:

Flashing/Boil-off will not occur if:

a) The break discharges two-phase fluid only;
b) The drywell achieves the higher temperatures before level is recovered such that the saturated liquid spilling out of the break and cooling the steam lines and drywell environment terminates the heatup transient;
c) The operator initiates drywell spray before the reactor is depressurized below 118 psia;
d) The reactor pressure is maintained above 118 psia.

In addition, even if flashing/boil-off were to occur, it would not be a concern if the operator follows the emergency procedure guidelines (EPG) and maintains reactor level in the normal water level range. Furthermore, the error due to flashing/boil-off will be eliminated if:

a) The operator follows the EPG and takes action to refill the reference leg after reactor depressurization if the temperature near the reference leg has exceeded the reactor saturation temperature and continues reactor injection until the temperature near the reference leg is below 212°F; or

b) The operator determines that a flashing/boil-off condition exists and takes corrective action to refill the reference leg. Indications available to the operator that indicate reference leg flashing/boil-off are:

   1) erratic level indication
   2) mismatch between narrow, wide and upset range level indicators and recorders (Note: Since EPG requires the operator to monitor water level from multiple indications, he should be aware of level instrument mismatch and hence flashing/boil-off conditions.)

Conclusion:

Considering the limited number of events, operator errors and conservative analysis assumptions described above, the probability of reference leg flashing/boil-off resulting in core uncovery is considered extremely low. Even if one assumes that the worst case scenario described above occurs, the operator would receive a level 2 alarm (keyed to the shorter reference leg) approximately 54 minutes prior to initial core uncovery. If this were disregarded, he would receive another level 2 alarm (keyed to the longer reference leg) approximately 12 minutes prior to initial core uncovery.

Based on the above, it is concluded that the Shoreham reactor water level measurement instrumentation is acceptable.

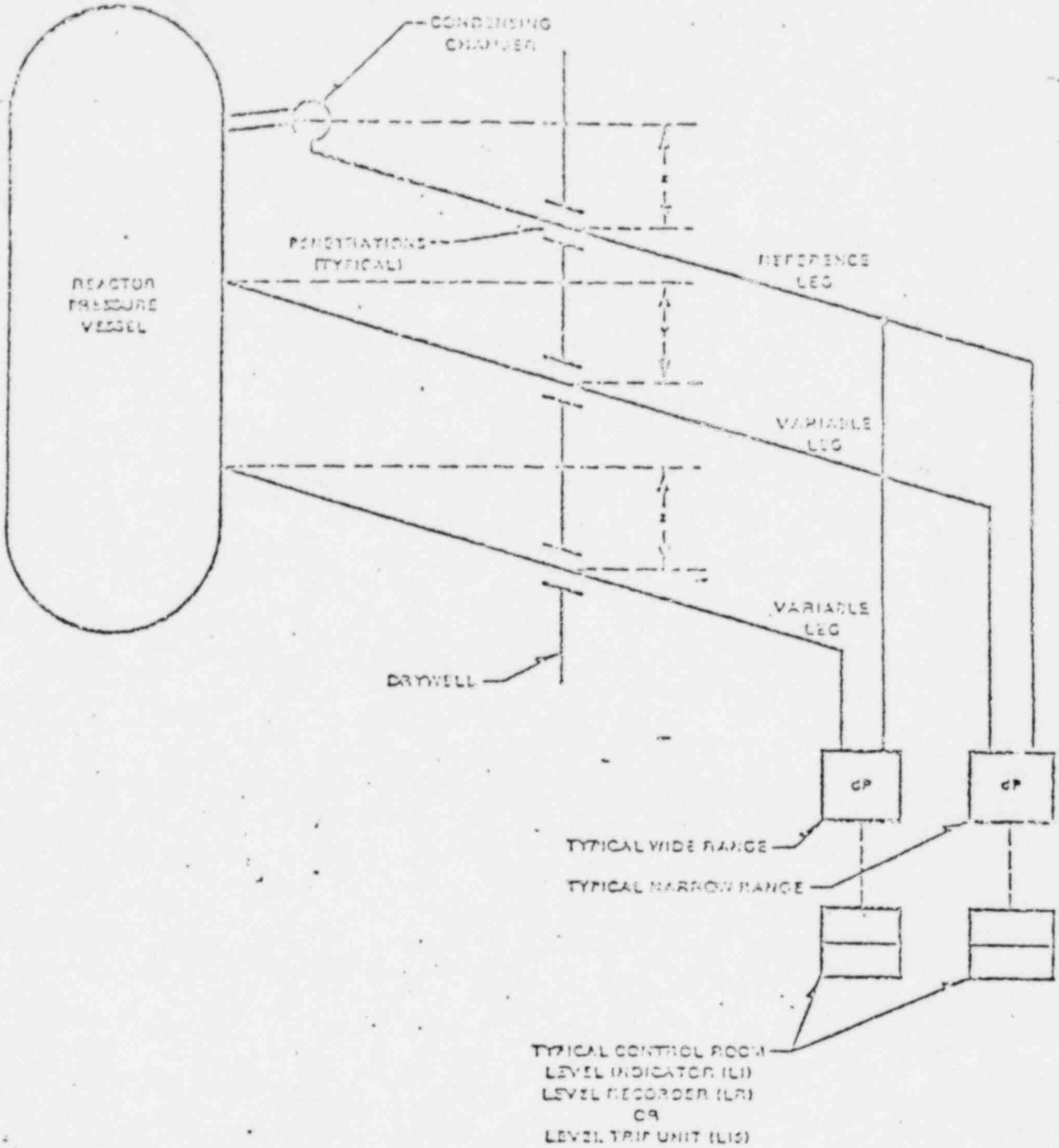

Figure 1 Cold Reference Leg Design

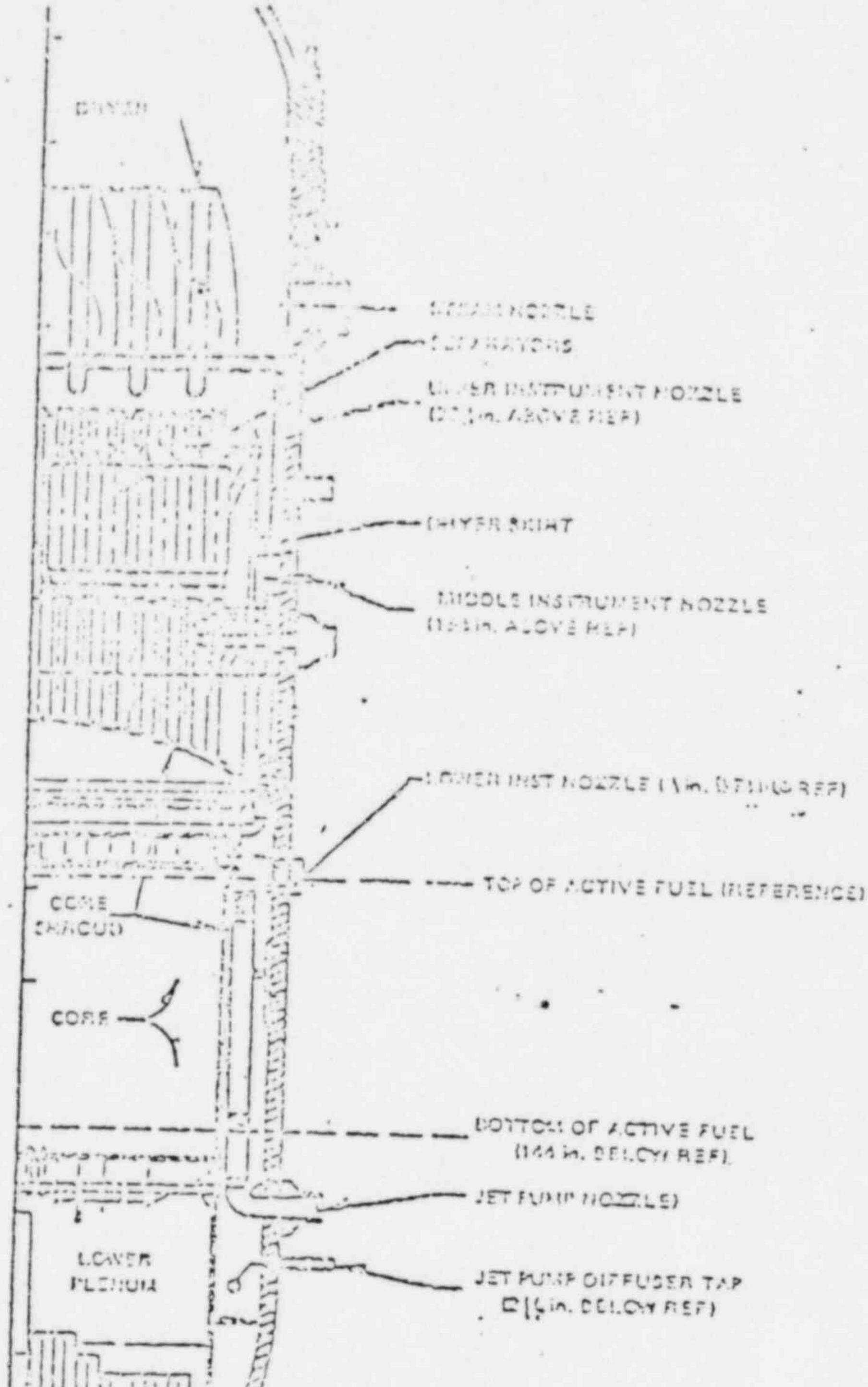

Figure 2 Location of Water Level Instrument Taps

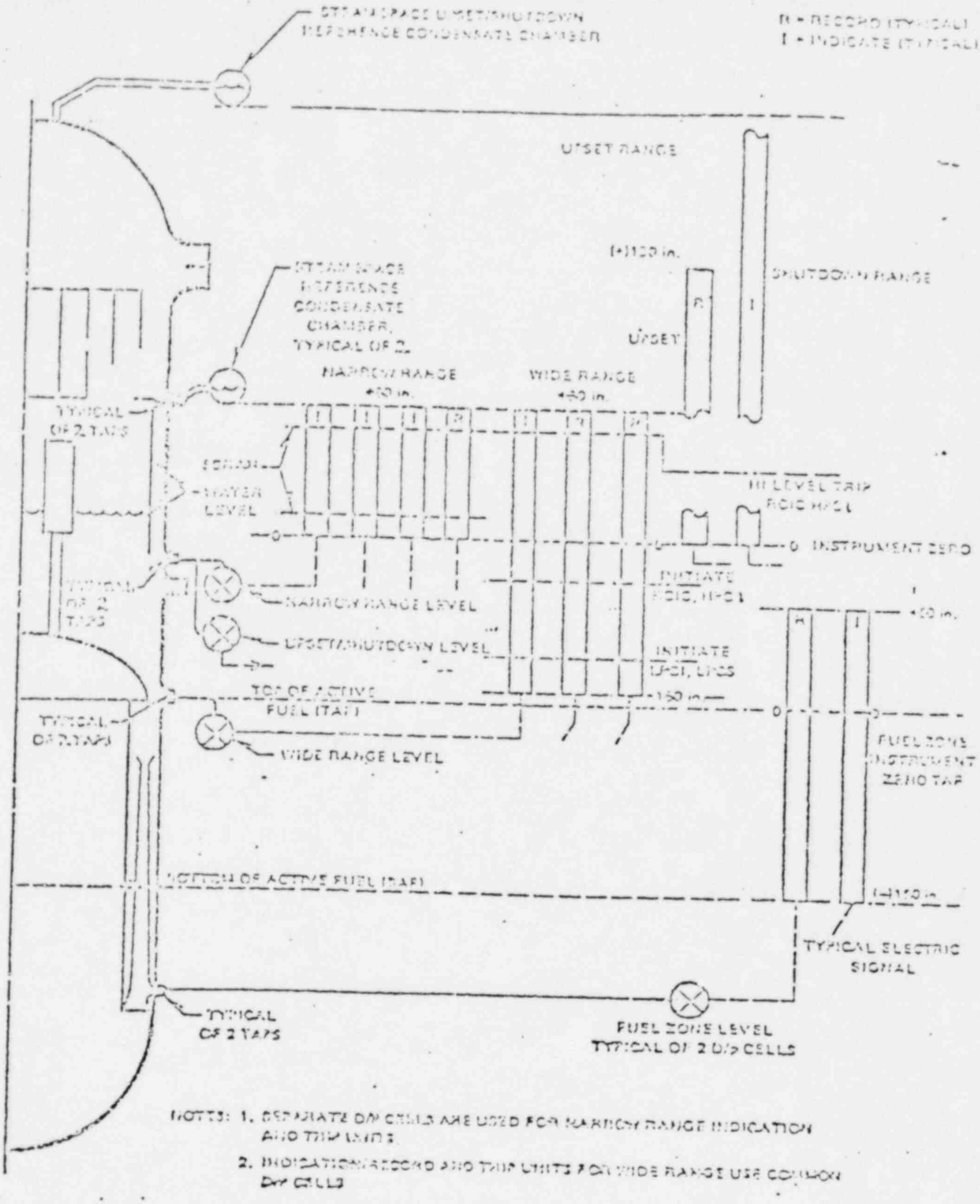

Figure 3 Typical Reactor Level Indicators on Reactor Control Panels

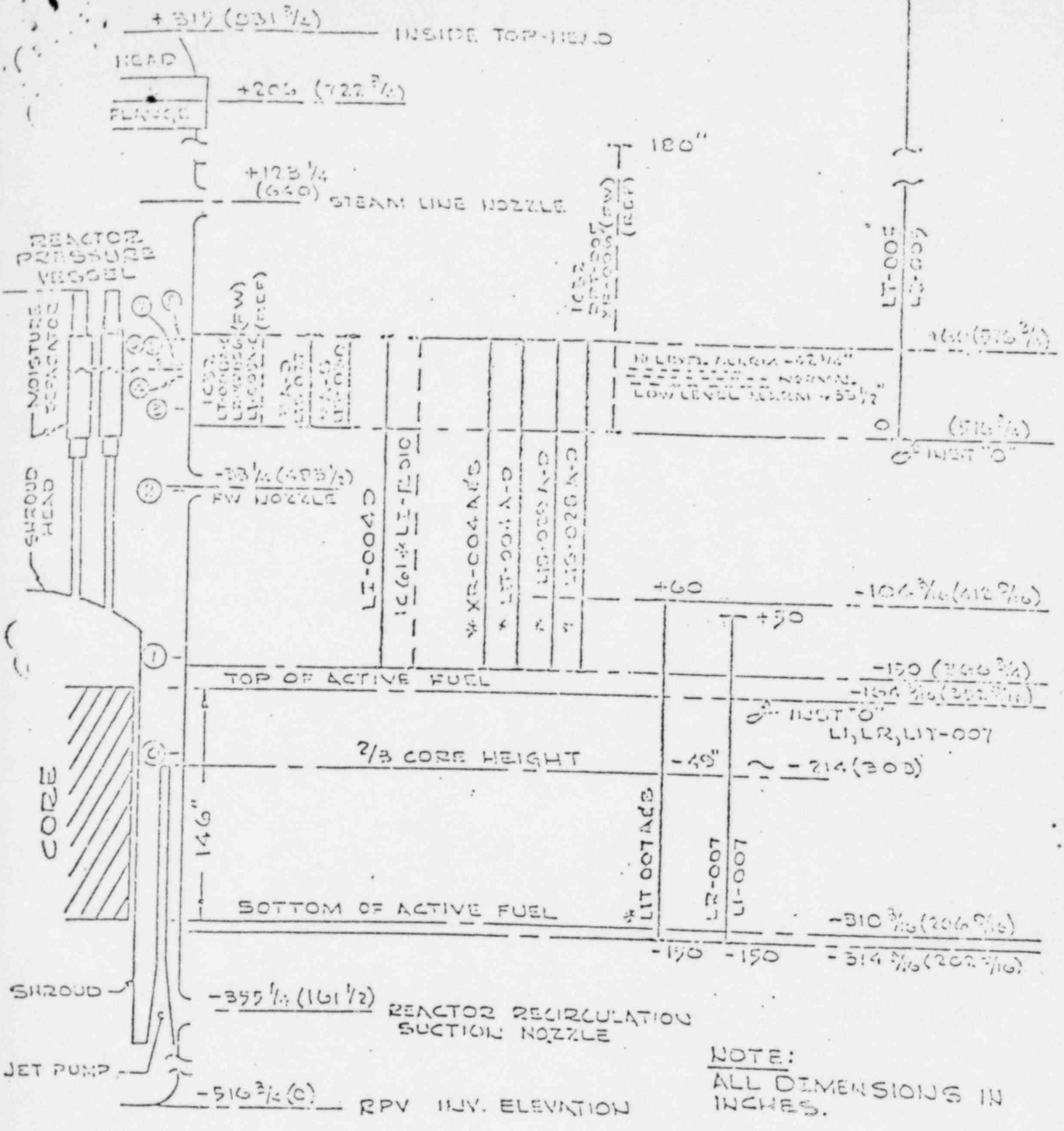

FIGURE 4. LEVEL - ELEVATION CORRELATION CHART

ATTACHMENT 2

Board Notification - Errors in BWR Vessel Water
Level Indication (BN-82-08) w/attachments
(Feb. 9, 1982)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

Docket Nos. 50-322
50-341
50-358
50-387/388
50-466
50-556/557

FEB 9 1982

MEMORANDUM FOR: The Atomic Safety & Licensing Boards for:

Shoreham Nuclear Power Station, Unit 1
Enrico Fermi Atomic Power Plant, Unit 2
William H. Zimmer Nuclear Power Station, Unit 1
Susquehanna Steam Electric Station, Units 1 and 2
Allens Creek Nuclear Generating Station, Unit 1
Black Fox Station, Units 1 and 2

FROM: Robert L. Tedesco
Assistant Director for Licensing
Division of Licensing

SUBJECT: BOARD NOTIFICATION - ERRORS IN BWR VESSEL WATER LEVEL INDICATION (Board Notification 82-08)

In accordance with present NRC procedures regarding Board notifications, the enclosed information is being provided for your information as constituting new information relevant and material to safety issues. This information is generic and has applicability to all dockets with boiling water reactors.

Robert L. Tedesco
Assistant Director for Licensing
Division of Licensing

Attachment:
DSI/NRR memo dated 1/15/82

cc: See next page

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

JAN 15 1982

MEMORANDUM FOR: Roger J. Mattson, Director
Division of Systems Integration

FROM: Themis P. Speis, Assistant Director for Reactor Safety
Division of Systems Integration

SUBJECT: ERRORS IN BWR VESSEL WATER LEVEL INDICATION

Attachment A provides a summary of the results of work done to date in the RSB and ICSB under Task Interface Agreement 81-21 "Pilgrim 1, Water Level Instrumentation Oscillation." It is emphasized that review of this issue is not complete, even though we have proposed some short and long-term recommendations. By copy of this memo, I am requesting that comments or other relevant feedback on the contents of this memo, and especially the proposed recommendations, be provided to C. Graves by 1/27/82.

Themis P. Speis, Assistant Director
for Reactor Safety
Division of Systems Integration

Enclosure:
As stated

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ATTACHMENT A

BWR WATER LEVEL INDICATION ERRORS

I. INTRODUCTION

On September 26, 1981, during a routine reactor shutdown and cooling operation at Pilgrim 1, there were several large oscillations of Yarway level detection indication (reference 1). The first oscillation caused high level isolation followed by low level scram. The oscillations were attributed to high containment temperatures, which caused flashing in the heated reference legs of the Yarway instruments. At the time, the reactor coolant temperature was about 220°F while the temperature in the upper part of the drywell was 240°F.

In a Task Interface Agreement of October 1981 (reference 2), NRR was assigned the following action plan items:

1. Review event to establish the generic licensing implications; (DSI/RSB & ICSB)
2. Review adequacy of Pilgrim Tech Spec on high containment temperature; (DSI/RSB)
3. Determine acceptability of oscillations in safety related instruments; (DSI/RSB & ICSB)

This memorandum summarizes the results of work in RSB and ICSB to date, provides preliminary responses to the Task Interface Agreement action items and lists some possible short and long-term solutions. It is emphasized that the information in this memorandum is preliminary since the review is not complete. A report dealing with the problem which was prepared for the BWR Owners was obtained from General Electric on 12/31/81 and has been given only a cursory review thus far. Detailed discussions with General Electric personnel will be held after staff review of the GE report.

BACKGROUND

As the result of the TMI-2 accident in March 1979, both the staff and industry have reviewed the adequacy of level detection instrumentation under accident conditions. In April, 1979, IE Bulletin 79-08 (reference 3) requested information from each licensee on vessel level indication. IE Bulletin 79-21, "Temperature Effects on Level Measurement" (reference 4) was issued in August, 1979. This bulletin addressed errors in steam generator water level resulting from high energy line breaks, including LOCA, inside containment and consequential high containment temperature which caused temperature increases and possible flashing of water in the reference leg of the level indicator. The problem was identified in a Westinghouse letter of June 1979. Although the bulletin required actions from PWR operators, it was also sent as information to all BWR operators. A staff letter (reference 5) addressing this problem was sent to all BWR licensees in July 1979. In July, 1979, General Electric notified its customers of false level indication caused by high temperatures and possible flashing of water in the reference legs of Yarway level instruments under post-LOCA conditions (reference 6). In September, 1980, General Electric again notified its customers of the importance of compensating for these false level indications in Yarway instruments and described false level indications in cold reference leg instruments caused by flashing in the sensing lines (reference 6). A staff review and evaluation of level instrumentation errors for BWRs, based on a review of GE information provided in August 1979 in NEDO-24708 (reference 7) is presented in NUREG-0626 (reference 8).

Additional info ation on the safety significance of errors in or total loss of level indication was provided during 1980 in NEDO-24708A (reference 9) and NEDO-25224 (reference 10). Some current information is available in the proposed emergency procedure guidelines for BWRs which are presently under staff review (see reference 11 and recent revisions) and in the Shoreham docket (reference 12).

II. WATER LEVEL INSTRUMENTATION

All level measurement systems in BWRs employ differential pressure transmitters, a reference leg connected to a condensing pot and in turn to the reactor vessel steam space, and a variable leg connected to the vessel at a lower elevation. Several differential pressure cells share common impulse legs. Temperature compensated and uncompensated reference legs are employed. Those level measurement systems which use a temperature compensated reference leg are called Yarways. Those level measurement systems which use an uncompensated reference leg are called cold leg instruments or, often, GEMAC.

BWR 1, 2, 3 and some 4's use two redundant Yarways to generate engineered safety feature actuation signals and cold reference leg instruments for indication and control. The remaining BWR 4's and all 5 and 6's use redundant cold reference leg systems exclusively.

Yarway (Heated Reference Leg) Instrument

A schematic of a Yarway level detector is presented in Figure 1. Steam condensed in the condensing chamber maintains the reference leg water level by overflow to the variable leg. The condensate heats the variable leg which, in turn, heats the reference leg. A thermal shield is provided to reduce heat loss to containment and to maintain relatively high reference leg temperatures. For short column Yarways, metal clamps have also been used to improve heat transfer between the legs. Information in reference 9 indicates that the reference leg temperature is roughly equal to local containment temperature plus 40 percent of the difference between reactor steam temperature and local containment temperature. For example, a local containment temperature of 135°F and steam temperature of 546° (Tsat at 1000 psia) would result in a reference leg temperature of 300°F.

The sensing lines leading from the Yarway to the differential pressure cell outside of the drywell are 1" schedule 80 stainless steel piping. Flow in these lines is blocked by the differential pressure cell. During normal operation, the stagnant water in these lines should be approximately at local containment temperature. If the lines are installed close to each other in containment, they should have about the same elevation change and local temperature. Hence, the effects of water density variations along the lines should be cancelled and have a minor effect on level measurement.

The Yarway level detector, which measures the collapsed water level in the outer annulus region of the reactor vessel, is subject to a number of uncertainites. Those resulting from differences between actual and assumed values of average coolant density in the annulus (affected by system pressure subcooling and carryunder) were shown to be small in reference 9. However, in 1979 the General Electric Company identified rather large uncertainties associated with high reference leg temperatures that could occur under some accident conditions (steam line breaks) for which local containment temperatures up to 340°F are predicted.

the high reference leg temperatures would result in false high water level signals. In addition, a constant indicated lower water level could be reached even though the actual water level has dropped well below the low level tap at the reactor vessel. Hence, GE recommended that its customers review calibration of the Yarway instruments, increase certain trip points and take other corrective actions to compensate for this effect.

High containment temperature combined with reactor depressurization can also lead to false water level readings because of flashing or boiling in the reference leg or the sensing lines within containment leading to the differential pressure sensor. Flashing in the lines might occur during depressurization if the local containment temperature exceeds the saturation temperature corresponding to vessel pressure. Flashing in the reference leg might be expected earlier in the transient because of the higher initial temperatures in the reference leg. The GE communication of 1979 was concerned only with the effects of flashing in the reference leg of Yarway instruments. Apparently, flashing in cold reference leg instruments was considered to be of minor importance at the time. In a later communication (September 1980), flashing in the sensing lines of cold reference leg instruments was also considered.

Flashing in the reference leg or lines could occur during normal system depressurization in preparing for initiation of RHR cooling or under accident conditions. During the cooldown event at Pilgrim on 9/26/81 (see reference 1), flashing of the reference legs in the Yarway instruments was indicated by several oscillations in the level readings. At the time, the reactor coolant temperature was 220°F and peak local containment temperatures were about 240°F. Under accident conditions such as a steamline break, local containment temperatures can reach 340°F. Hence, when vessel pressure drops below about 112 psig (p_{sat} at 340°F) flashing could occur in the lines. If it is assumed that the reference leg temperature rapidly increases to the steady state value for a containment temperature of 340°F and RCS temperature of 546°F, flashing in the reference leg might occur when vessel pressure drops below about 300 psig (P_{sat} at 422°F).

Another scenario involving flashing in the reference leg could occur for larger breaks and times such that the vessel pressure is about equal to containment pressure. In this case, as discussed in reference 13, the rapid reduction in containment pressure following initiation of the containment spray, combined with the delay in reduction of metal temperatures, could cause flashing in the reference leg. Tests were conducted to confirm that large errors in level indication could occur. The solution to this flashing problem involved installation of a cooling jacket around the reference leg which was supplied with water from the containment spray line.

Even without a break, loss of the non-safety grade containment coolers would cause the containment to heat up and could cause flashing upon depressurization.

With respect to the flashing problem it should be noted that there would be a time delay involved in the heating of the reference leg and lines under accident conditions. A delay in heat transfer would be expected because of the relatively large amount of metal in the walls of the reference leg and lines and the relatively low heat transfer coefficients expected for surfaces in contact with the containment atmosphere. In reference 9, the thermal time constant for the Yarway detector was estimated to be about 20 minutes. This value may have been calculated assuming only high temperature air. For steam-air mixtures, the condensation on cold surfaces results in appreciably larger heat transfer coefficients than those for air at the same temperature. It should also be noted that water expelled by flashing in the heated reference leg and corresponding line to the differential pressure sensor may not be replaced quickly. At the high containment temperatures and lower vessel pressure expected under accident conditions, the condensing chamber could cease to function. Hence, refill would be delayed until sometime after the vessel water level increases to a point above the tap leading to the condensing chamber. Even under these circumstances, boiling could occur for a while in the reference leg and lines as the result of continued high local containment temperatures. In the case of degraded core cooling when water level remains well below the tap to the condensing chamber and noncondensible gases and superheated steam could be present, there could be extended time periods with large false indications of vessel water level. In fact, purging of the lines could be required to remove non-condensibles.

Cold Reference Leg Instruments

A schematic of a cold reference leg instrument is presented in Figure 2. In this case, the reference leg upper level is maintained by overflow of condensate in the condensing chamber back through the tap to the vessel. Water density effects and flashing in the lines within containment which lead to the differential pressure sensor could be of concern. Changes of elevation in the lines inside of containment range from 1 to 40 feet in operating plants. Hence, flashing in the lines under accident conditions could cause false water level indications and delay in refill problems, such as those discussed in Section A. Flashing in cold reference leg level instrument lines was recognized in the guidelines developed by GE (reference 11). This situation (loss of reliable level indication for both heated and cold reference leg detectors) was treated by operator instructions to initiate ADS and ECCS actuation to fill the vessel and overflow to the suppression pool via the S/R valves.

RESPONSE TO SPECIFIC ACTION ITEMS:

1. Review event to establish the generic licensing implications.

   All BWR vessel level instrumentation, to some degree, is susceptible to reference leg flashing and consequential loss of level indication following rapid vessel depressurization such as observed at Pilgrim. The generic BWR emergency procedure guidelines* include caution and action statements related to loss of level indication. The susceptability of the level indication system to substantive non-conservative errors during event sequences which include depressurization, and the adequacy of emergency procedures is discussed below.

2. Review adequacy of Pilgrim Technical Specification on high containment temperature.

   The Pilgrim Technical Specifications do not include drywell temperature as a limiting condition for operation. We believe such a specification would be prudent to prevent undue equipment aging. However, a LCO on the pre-accident drywell temperature will <u>not</u> preclude post accident loss of vessel level indication.

3. Determine acceptability of oscillation in safety related instruments.

   Engineered safety feature actuation signals are generated using the following process variables:

   High pressure core spray (HPCS) - vessel level or drywell pressure

   Low pressure core spray (LPCS) - vessel level or drywell pressure

*These guidelines are presently under review by the staff and are not, to date, employed at Operating Reactors.

Low pressure coolant injection (LPCI) - vessel level or drywell pressure

Automatic depressurization system (ADS) - vessel level and drywell pressure

Containment Spray (CS) - vessel level and drywell pressure

Reactor Core Isolation Cooling (RCIC) - vessel level only.

Delays in initiation of engineered safety features due to reference leg heatup and boiloff have been considered in response to IE Bulletins 79-08 and 79-21. The staff concluded in NUREG-0626 that for all break sizes, the reactor either depressurizes fast enough to allow timely initiation of the low pressure system on high drywell pressure, or the breaks are small enough that (at worst) ECC functions occurred before the potential boiling of the reference leg fluid.

Furthermore, ESFAS systems employ latching circuitry except on the ADS level permissive to ensure that safety actions, once initiated, go to completion (IEEE 279).

Hence, concerns related to initiation accuracy for automatic safety systems due to reference leg heatup and/or flashing and concerns related to potential reference leg fluid oscillation have been previously and adequately addressed for design basis events: however, there are event sequences involving multiple equipment failure which will require manual initiation of engineered safety features.

For some accident scenarios involving a break inside containment, adequate indication of actual vessel water level could be lost for all pertinent level instruments as the result of flashing and boiling in the reference legs. The emergency guidelines (reference 11 and revisions) consider the case where the operator has recognized that vessel level cannot be determined. For this case, the guidelines involve actions to depressurize the reactor and to refill the system until it overflows to the suppression pool via the S/R valves. However, if the operator fails to recognize that he has lost level indication and has a false high reading of water level, he might take action to throttle or stop ECCS systems in order to avoid filling steam lines or to reduce load on emergency power systems. In this case, the flashing or boiling in the reference legs could lead to operator actions prejudicial to plant safety.

RECOMMENDATIONS

These are preliminary. Once we have received feedback from people on the distribution list and met with the BWR Owners Group, they will be finalized.

A. Short-Term Recommendations

(1) Operators should be warned that all level indication is susceptible to large inaccuracies. We are concerned that operators may have been trained to unduly depend upon cold leg instrumentation should they recognize errors in Yarway reference leg instrumentation.

A cursory examination of plant procedures at Pilgrim 1 and Browns Ferry show that concerns related to cold leg instrumentation inaccuracies have not been incorporated in their procedures. The operators may have been warned of these concerns by other mechanisms such as training sessions. We believe that utilities are aware of potential water level inaccuracies in Yarway and cold leg instrumentation based on staff review of GE documents prepared for the staff and documents prepared for GE owners. Early documents recommended reliance on cold leg instrumentation. Later documents warned that these instruments, depending on the plant specific installation, might also exhibit substantive indicated level errors. We do not know whether or not these concerns and corresponding warnings and actions have been communicated to the control room operators.

(2) Plant specific emergency procedures should be confirmed and/or modified to:

(a) Clearly identify which level indicators in the control room employ Yarway reference legs and which employ cold reference legs, and direct the operator to the appropriate indicators.

(b) Include procedures to help the operator decide when level instrumentation is to be mistrusted. Relate specific drywell temperature indication, readily and reliably available to the operator in the control room, to reference leg temperature.

(c) Include procedures to help the operator recognize those plant conditions and observed instrument responses which indicate successful refilling of reference legs following flashing.

(3) Operability limits of the temperature sensors used in (2)(b) above should be included in the plant Technical Specifications.

B. Long-Term Recommendations

We believe that it is prudent to provide the operator with continuous reliable level information. Event sequences have been identified during which reliable indication will be temporarily lost. This potential is addressed in the emergency procedure guidelines now under review by the staff. Hardware modifications should be sought to address this problem.

We believe that operator recognition of loss of accurate level information as addressed in the emergency procedure guidelines is cumbersome at best. The operator is to relate indicated water level and drywell temperature using a table contained in a caution statement of the emergency procedures. Indicated water level values beyond the ranges shown in the table are to be mistrusted. Automation of these actions and decisions seems in order.

Should the operator decide that the water level indicators are to be mistrusted, the operator is to fill the vessel. Supposedly reference legs would ultimately refill. At some point in the event sequence, the operator should be provided with positive means to confirm that reliable water level indication has been restored. This problem may not be adequately addressed in the emergency guideline procedures which are presently under staff review.

Several potential plant modifications are being considered by the staff. It is not our intent to dictate hardware fixes. Rather, we give the below recommendations as illustrations that reference leg flashing is a tractable problem.

(1) Perform plant specific analysis of susceptibility of cold leg level instrumentation to reference leg flashing and/or local heatup and corresponding water expulsion. Those plants which are designed with small vertical drops of reference legs inside the drywell should be satisfactory as designed.

(2) Consider rerouting of reference legs to meet condition (1) above.

(3) Install temperature measurement of the reference leg. Such measurements ould be used to confirm operability following a drywell temperature excursion and subsequent cooldown. The measurement would be of little use should high drywell temperatures be sustained.

(4) Develop means to cool the reference leg by establishing flow within the leg. Two techniques have been suggested: (1) the temporary opening of equalization valves and/or drain valves, and (2) pumping water with a positive displacement pump from outside the drywell, up reference lines and into the vessel. Equalization and drain valves are local manual valves. They are hypothetically accessible following an accident. The drain lines are routed to the waste treatment system. Following vessel depressurization, reference leg flashing and subsequent vessel filling in accordance with emergency procedures, temporary opening of the valves could be used to ensure reference leg filling. No hardware modifications would be required. Should a sufficiently large LOCA occur, or should an event sequence involving multiple equipment failure occur, such that the

vessel cannot be filled above the reference leg taps, this technique would be of little use. Pumping water up reference legs would obviously require hardware modifications. The flowrate need only be high enough to overcome the heat load on the reference legs inside the drywell under accident conditions. This technique would permit reference leg filling even if high drywell temperatures existed and the vessel could not be filled to the reference leg tap.

(5) Develop means to cool the reference leg by using a coolant jacket and diverted ESF flow.

REFERENCES

1. Licensee Event Report 81-055/01T-0, "High Drywell Temperatures". Pilgrim Nuclear Power Station, 10/15/81.

2. Task Interface Agreement, Task No. 81-21, "Pilgrim 1, Water Level Instrumentation Oscillation", October, 1981.

3. IE Bulletin 79-08, "Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident", April 14, 1979.

4. IE Bulletin 79-21, "Temperature Effects on Level Measurements", August 9, 1979.

5. Letter from T. Ippolito, NRC to C. Reed, Commonwealth Edison Company, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", July 13, 1979.

6. Telephone conversation with General Electric Company personnel, December, 1981.

7. NEDO 24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", August, 1979.

8. NUREG-0626, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in GE-Designed Operating Plants and Near-Term Operating License Applications", January, 1980.

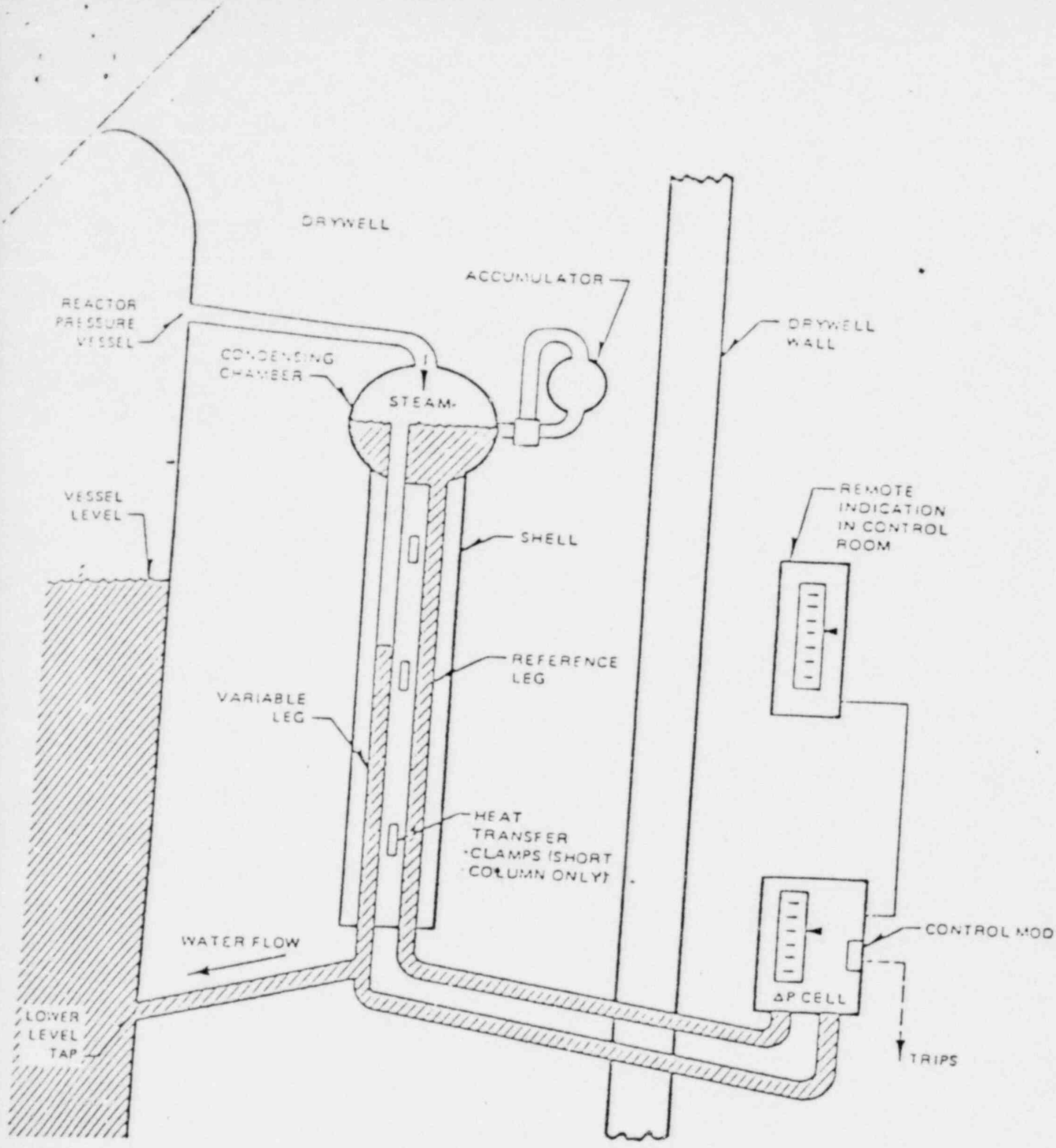
9. NEDO 24708A, Revision 1, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", December, 1980.

). NEDO 25224, "GESSAR Assessment Report, Review of BWR/6 Protection In-Depth for Transient and Accident Events", June, 1980.

. NEDO 24934, "Emergency Procedures Guidelines - BWR1-6", January, 1981.

. Attachment to letter from B. McCaffery of Shoreham Nuclear Power Station to H. Denton, NRC, August 18, 1981.

. Memorandum to Carl Berlinger, CPB, NRR, and Faust Rosa, ICSB/NRR, from N. Kondic, ICB, DFO, "Two Phase Fluid Water Level in Nuclear Vessels (Reactor SG, PZR), November 23, 1981.



ure 1. Yarway (Heated Reference Leg) Level Detection Instrucment
(From NEDO-24708A)

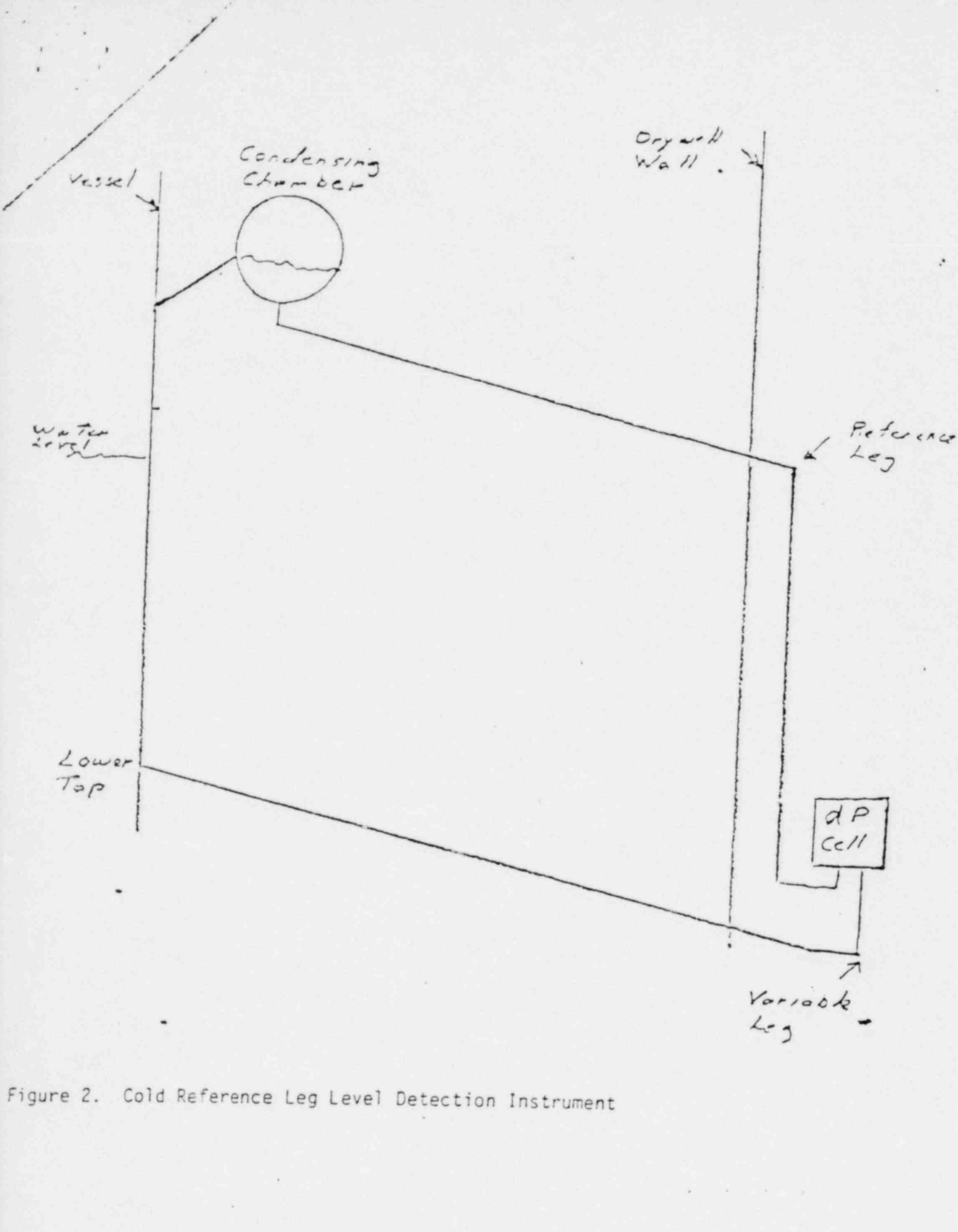


Figure 2. Cold Reference Leg Level Detection Instrument

ATTACHMENT 3

"Safety Concern Associated with Reactor Vessel Level
Instrumentation in Boiling Water Reactors"
from C. Michelson, NRC Office for Analysis and Evaluation
of Operational Data to H. Denton, NRR (January 20, 1982)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

JAN 20 1982

MEMORANDUM FOR: Harold R. Denton, Director
Office of Nuclear Reactor Regulation

FROM: Carlyle Michelson, Director
Office for Analysis and Evaluation
of Operational Data

SUBJECT: SAFETY CONCERN ASSOCIATED WITH REACTOR VESSEL LEVEL INSTRUMENTATION IN BOILING WATER REACTORS

Following completion of the peer review, we have completed our case study (enclosure) on vessel level instrumentation in boiling water reactors (BWRs). The study was initiated following events at Brunswick 1 on January 20, 1981 and Browns Ferry 2 on March 31, 1981.

The study included the review of a number of operating reactor events involving BWR vessel level instrumentation. The review has shown several cases where interaction between plant control systems and protection systems are evident. Our evaluation of these cases has raised the safety concern of a single random failure in the vessel level instrumentation system causing a control system action that could (1) result in a station condition requiring protective action and, at the same time, (2) prevent proper action of some of the protection system channels designed to protect against such a condition, leaving the remaining protection system channels to provide the protective function. A further single active failure in the remaining channels could then prevent the required protective actions.

The study addresses the interaction between feedwater control, reactor protection, containment isolation and emergency core cooling systems and includes our findings and recommendations regarding these systems and the safety concern.

Although we do not consider the postulated control system or protection system interaction an immediate concern, we do consider that the safety concern and associated problems need to be addressed. Thus, the enclosed report is forwarded for your information and appropriate action.

If you have any questions regarding this report, please contact Frank Ashe or Matthew Chiramal of my staff. Mr. Ashe can be reached at 492-4442 and Mr. Chiramal at 492-4441.

Carlyle Michelson

Carlyle Michelson, Director
Office for Analysis and Evaluation
of Operational Data

Enclosure:
As stated

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RDeYoung, IE
RMinogue, RES
RMattson, NRR
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GLainas, NRR
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FRosa, NRR
RBernero, RES
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JTBeard, NRR
EWenzinger, RES
ASzukiewicz, NRR
DTondi, NRR
TIppolito, NRR
RJClark, NRR
JVanVliet, NRR
VStello , DEDROGR
TMurley, DEDROGR
JShea, IP
PCollins, NRR
JTaylor, IE
EJordan, IE
WMills, IE
VThomas, IE
RHaynes, Region I
JPO'Reilly, Region II
JGKeppler, Region III
JTCollins, Region IV
RHEngelken, Region V

SAFETY CONCERN ASSOCIATED WITH REACTOR VESSEL LEVEL INSTRUMENTATION IN BOILING WATER REACTORS

by the

OFFICE FOR ANALYSIS AND EVALUATION

OF OPERATIONAL DATA

January 1982

Prepared by: Matthew Chiramal
Frank Ashe

Note: This report documents results of studies prepared by the Office for Analysis and Evaluation of Operational Data with regard to several operating events. The findings contained in this report are provided in support of other ongoing NRC activities concerning these events. Since the studies are ongoing, the report is not necessarily final, and the findings do not represent the position or requirements of the program office of the Nuclear Regulatory Commission.

TABLE OF CONTENTS

EXECUTIVE SUMMARY. . . . .

1. BACKGROUND . . . .

2. DISCUSSION OF SAFETY CONCERN . . . .

   2.1 Description of Reactor Vessel Level Instrument Monitoring Normal or Narrow Range . . . . .
   2.2 Effect of Instrument Line Failure on Plant Protection and Control Systems. . . . . .
   2.3 The Safety Concern and Related Regulations. .
   2.4 Possible Unanalyzed Sequence of Occurrences .

3. FINDINGS . . . .

4. CONCLUSION . . . .

5. RECOMMENDATIONS. . . . .

LIST OF FIGURES

Figure - 1 REACTOR VESSEL LEVEL INSTRUMENTATION . . . .

Figure - 2 VESSEL WATER LEVEL BLOCK DIAGRAM . . . . . .

APPENDIX A EVENTS INVOLVING BWR LEVEL INSTRUMENTATION .

EXECUTIVE SUMMARY

Our review of operating reactor events involving boiling water reactor (BWR) vessel level instrumentation has shown several cases where interaction between plant control systems and protection systems is evident. This interaction is basically due to fluid coupling and sharing of instrument sensing lines by the attached sensors that monitor vessel level and provide input to the protection and control systems.

Our review of these cases has raised the safety concern of a single failure causing a control system action that (1) results in a station condition requiring protective action and, at the same time, (2) prevents proper actuation of protection system channels designed to protect against such a condition. We believe the physical installation of certain BWR level instrumentation may not fully meet the intent of the regulations for the separation of protection and control systems and the single failure criteria, as delineated in General Design Criterion 24. Based upon operating experience, we believe that a single random failure in the instrument sensing lines should now be considered in implementing IEEE 279-1971.

In this study we have not conducted a detailed plant specific review of level instrumentation installation, but have confined ourselves to a general evaluation. This study addresses the interaction between feedwater control, reactor protection, primary containment isolation, and emergency core cooling systems. The effect of the interaction may vary from that detailed in this study depending on the details of the installation of the instrumentation. We plan to expand the scope of the study later to consider the effects of interactions due to level instrumentation permissive interlocks provided to the recirculation pump control and residual heat removal systems.

This report is intended to introduce the safety concern related to BWR vessel level instrumentation. We note that similar fluid coupling problems could exist between control and protection system instrumentation that monitor other parameters such as steam flow, water flow and liquid levels at both BWRs and PWRs. However, our initial review of operating reactor events has identified the BWR vessel level instrumentation system specifically as one that involves such problems. We plan to continue our reviews of operating experiences at both BWRs and PWRs for events involving similar problems that could affect safe operation of nuclear plant units.

1. BACKGROUND

In the design of the instrumentation used in control and protection systems, conscious effort has been made to physically separate the different sensors used. In reviewing BWR vessel level instrumentation drawings of operating plants provided in FSARs and in other associated documentation (e.g., NEDO 10139, "Compliance of Protection System to Industry Criteria: GE BWR NSSS," June 1970), we note that the sensors used for control systems were shown mounted on instrument lines that are separate from other instrument lines associated with sensors used in protection systems. However, review of operating experience and a few of the "as built" instrumentation drawings show that sensors for protection and control systems may be mounted on common instrument lines.

This study is based on Licensee Event Reports (LERs) and Nuclear Power Experiences (NPEs) involving BWR level instrumentation. The events are listed in Appendix A. The events cited are examples of how occurrences involving instrument lines and/or related items can lead to erroneous reactor vessel level indications. The problem of control and protection system interaction studied here is applicable to operating BWRs and those with construction permits.

2. DISCUSSION OF SAFETY CONCERN

There have been a number of documented events involving potentially erroneous indications by reactor vessel water level instrumentation at operating BWRs (Appendix A). The events in general show that a single failure involving one of the instrument legs connected to the level measuring differential pressure cells could affect all instruments connected to either or both legs. A review of each event shows that the effect on the plant varies, depending on the instruments affected and on the function of those instruments. Thus, the initiating failure either led to a plant trip or was detected and corrected by the plant operators without significantly affecting plant operation. Our review ranged further afield to consider the control and protective functions of the instruments involved.

BWR vessel water level is measured by means of differential pressure sensed across two instrument lines. In general, operating BWRs use four constant reference legs and seven variable legs (see Figure 1 for a typical installation). The constant reference is obtained by means of constant head condensing chambers. Two of the condensing chambers have a temperature compensated column and an auxiliary head chamber. The other chambers have no temperature compensation. The level instruments connected to temperature compensated reference legs are used to monitor vessel water level in the accident or wide range (typically -155 to +60 inches with instrument zero 528 inches above vessel zero.) The two without temperature compensated reference legs are used for normal or narrow range level instrumentation (zero to 60 inches with instrument zero 528 inches above vessel zero.) These reference legs are also used for instruments that monitor water level inside the core shroud (-100 inches to +200 inches with instrument zero 360 inches above vessel zero.) A fifth reference chamber is for the water level instrumentation in the refuel range (zero to +400 inches with instrument zero 528 inches above vessel zero.)

Review of the LERs raised a concern regarding the level instrumentation that monitors the normal or narrow range of the vessel water level. This is discussed below.

2.1 Description of Reactor Vessel Level Instrumentation Monitoring Normal or Narrow Range

The level instruments that monitor normal or narrow range of the vessel water level are connected across two pairs of instrument lines (See Figure 1). One pair of instrument lines has the following level instruments:

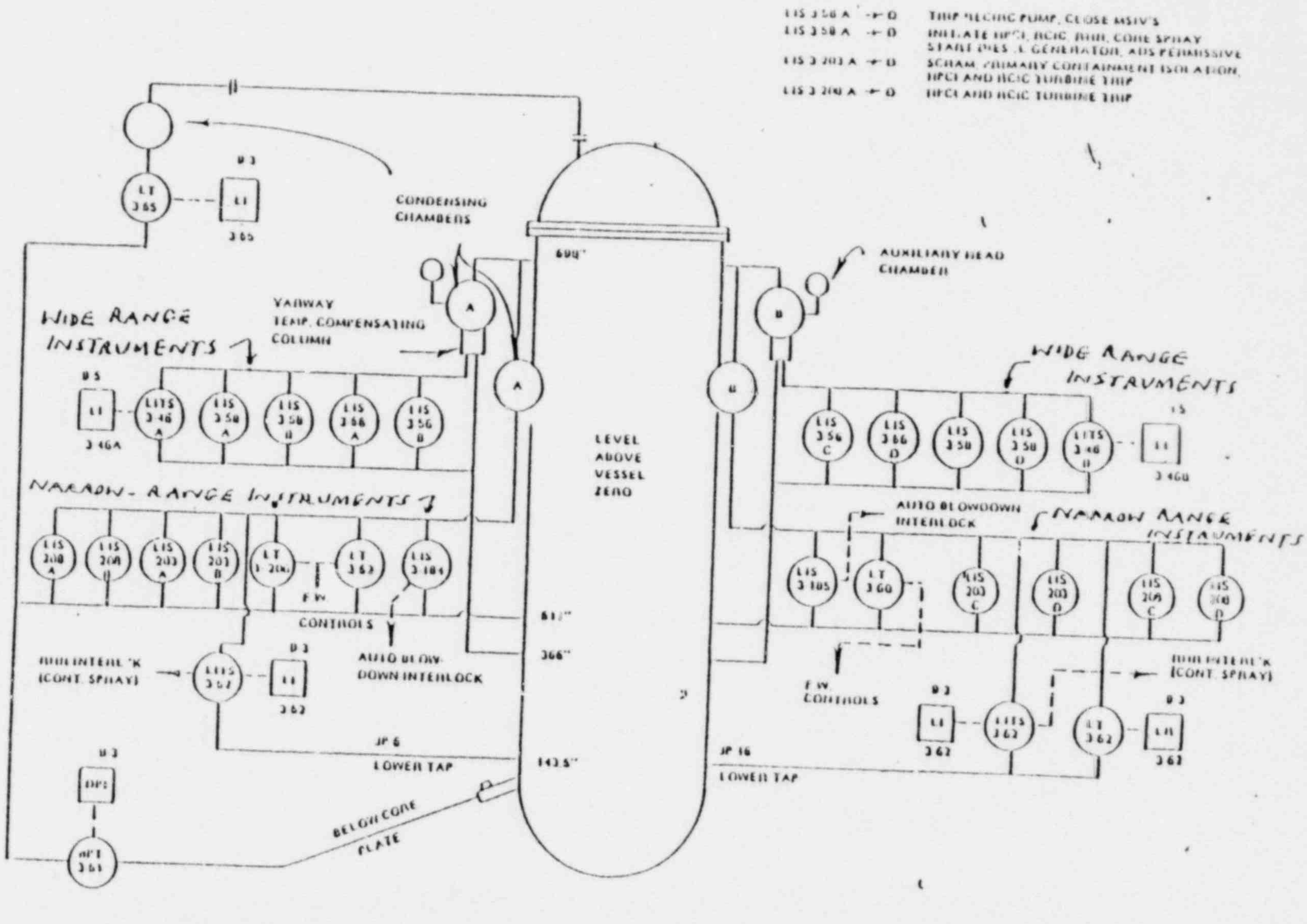

FIGURE 1 — Reactor Vessel Level Instrumentation

LIS 3-208A and 3-208B
LIS 3-203A and 3-203B
LIS 3-184
.LT 3-206 and LT 3-53

The constant reference leg associated with these instruments is also used as the reference for the shroud level monitor LITS 3-52. The other pair of instrument lines has:

LIS 3-208C and 3-208D
LIS 3-203C and 3-203D
LIS 3-185
LT 3-60

The constant reference leg is also used by shroud level monitors LITS 3-62 and LT 3-62.

The functions performed by these instruments are as follows:

LIS 3-208 A, B, C, D	HPCI and RCIC turbine trip on high vessel level.
LIS 3-203 A, B, C, D	Scram and primary containment isolation on low level. HPCI and RCIC turbine trip on high level.
LIS 3-184 and LIS 3-185	Auto blowdown permissive on low level.
LT 3-53, LT 3-60 and 3-206	Feedwater control system inputs (A high water level trip of the main and reactor feedwater turbine is also provided by the feedwater control system).
LITS 3-52 and LIS 3-62	Containment spray interlock on low-low-low level.

The physical arrangement of these level instruments on two separate sets of instrument lines is such that the A and B sensors are connected to one set of instrument lines and the C and D sensors to another set. These sensors provide input to protection channels in the plant protection and emergency core cooling systems. The protection system and emergency core cooling system logic arrangements for these BWR instrument channels are the usual one-out-of-two-twice configuration using channel (A OR C) AND (B OR D) arrangement. The two sets of instrument lines are separated and isolated in their physical connection to the reactor pressure vessel. Thus, the arrangement of these level instruments associated with the plant protection system meets the Single Failure Criterion of IEEE 279-1971, paragraph 4.2.

The same instrument lines, however, also have reactor vessel level control transmitters (LT 3-53 and LT 3-206 on one set; LT 3-60 on the other) mounted on them. These transmitters provide input to the plant's feedwater control system (See Figure 2). Each transmitter provides an output signal ranging from 10-50 ma, which represents the normal water level ranging from zero to +60 inches at normal operating pressure. Corrections for water density changes are made by reactor pressure measurements. Signals from pressure transmitters (shown on Figure 2) are applied to level correction amplifiers to accomplish this. Each of the three corrected level signals is applied to an alarm unit. The three alarm unit outputs are connected in a two-out-of-three coincidence logical to provide high water level trip (+64 inches) to the main and reactor feedwater turbines. The three corrected signals are also displayed in the control room, as are the three pressure monitors. The corrected level signal from either transmitter LT 3-53 or LT 3-60 is selected by the control room operator for use in the feedwater control system. The selected level signal is recorded in the control room. It is also supplied to two alarm units, the feedwater bypass valve controller, a level flow error summing device, and the feedwater control mode selector switch (one or three element control).

For BWRs in general, eight reactor vessel level indicators and two recorders are provided in the main control room to aid the operator. High and low level

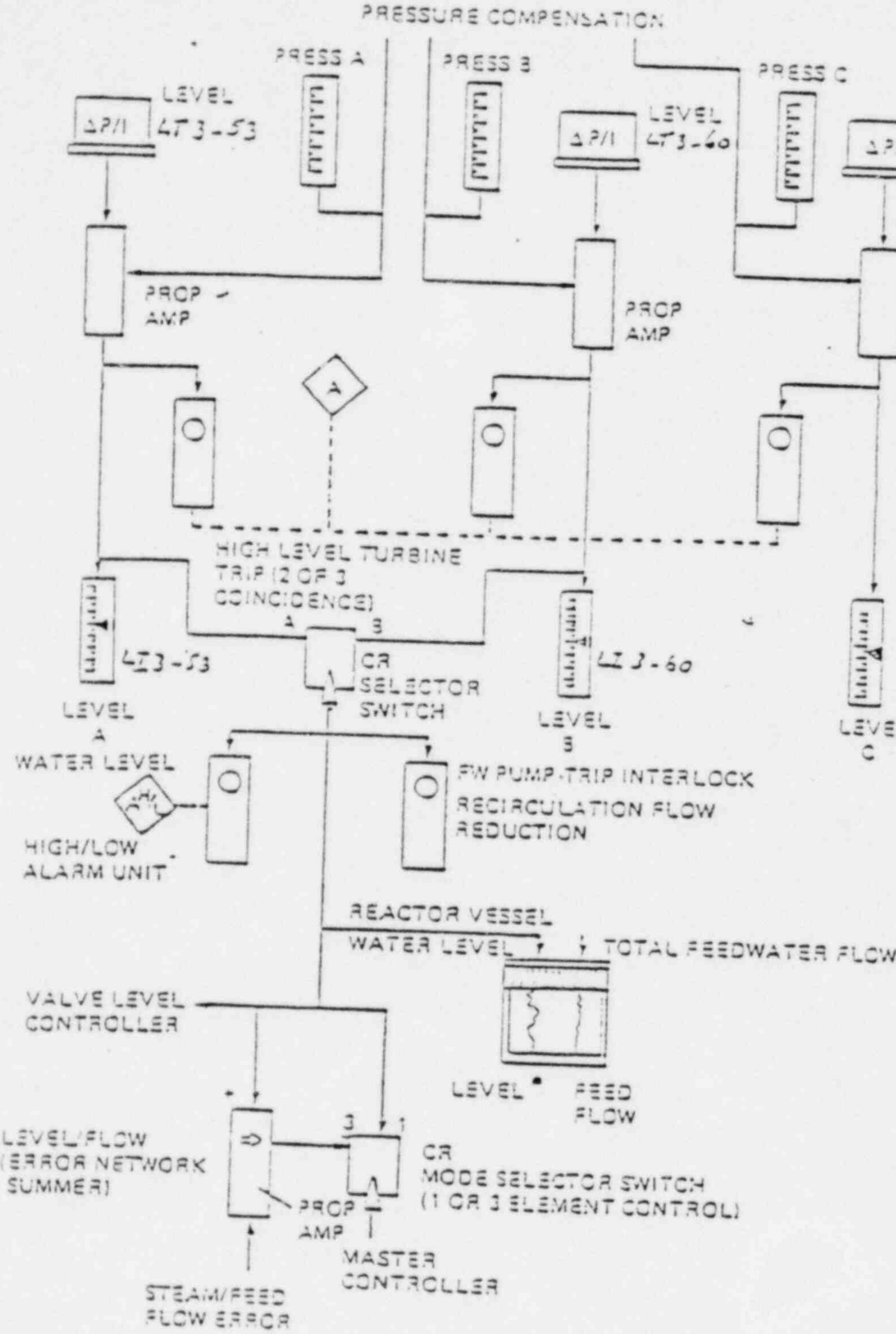

Figure 2 - Vessel Water Level Block Diagram

digital inputs to the control room annunciator system and the plant computer system also inform the operator .. vessel level status.

The control room indicators and recorders are:

(1) two level indicators (LI 3-52 and LI 3-62) and one level recorder (LR 3-62) monitor the shroud level. These instruments are normally pegged high at +200 inches during power operation;

(2) one level indicator (LI 3-55) monitors the refueling range (zero to +400 inches);

(3) two level indicators (LI 3-46A and LI 3-46B) monitor the accident range (-155 inches to + 60 inches);

(4) three level indicators (LI 3-53, LI 3-60 and LI 3-206) monitor normal range (zero to +60 inches). A reactor level/feed flow two pen recorder in the control room also continuously monitors the level signal selected for the feedwater control system (either LI 3-53 or LI 3-60 signal).

During normal power operation, five indicators and one recorder (numbers 3 and 4 above) would be used by the operator to monitor level. Control room alarms would alert the operator to abnormal conditions. The refueling range level indicator (number 2 above) is not calibrated for operating conditions and is not used during normal operation.

2.2 Effect of Instrument Line Failure on Plant Protection and Control Systems

A failure in the instrument line connected to the constant head condensing chamber (e.g. equalizing valve leak, excess flow check valve leak, drain valve leak, etc.) could cause the reference leg level to decrease. This decrease in reference leg level would cause all the differential pressure instruments connected to that line to indicate false high reactor vessel water level.

Referring to Figure [illegible], if such a failure was to occur in the reference leg of the normal range level sensors A and B, then LIS 3-208A&B, LIS 3-203 A&B, LIS 3-184, LT 3-53 and LT 3-206 would all sense an increasing level. If LT 3-53 was selected by the control room operator for the level input to the feedwater control system (with the feedwater control mode switch in either the one or three element control), then the feedwater system would reduce feedwater flow into the reactor vessel. This would tend to decrease the actual reactor vessel water level. If prompt operator action is not taken to manually control the feedwater system, then eventually the vessel level would reach the low level scram setpoint. However, scram level sensors LIS 3-203A&B would sense a high level and would not actuate. Therefore, LIS 3-203C&D on the redundant instrument lines would be required to provide the necessary protective action.

In such an event the control room level indicators, recorders and alarms would be providing ambiguous level information to the operator. The two accident range indicators (LI 3-46 A&B) would still show true level, but only one of the normal range level indicators (in this instance LI 3-60) would indicate true level. The other two normal range level indicators (LI 3-53 and LI 3-206), as well as the level recorder pen, would show an erroneous high level. If, on the other hand, the failure was to occur in the reference leg associated with normal level sensors C and D (i.e.,

LIS 3-203 C&D, LIS 3-208 C&D, LIS 3-185 and LT 3-60) and if LT 3-60 was selected for level input to the feedwater control system, the effects would be similar, with the following exceptions: (1) only one normal range level indicator (LI 3-60) and the level recorder would show the erroneous increasing level; and (2) the high level turbine/reactor trip would not occur, since only one of the three level transmitters associated with the feedwater control system would be affected.

In either case, during the ensuing plant transient, both high and low level alarms could be actuated in the control room. Depending on the type of instrument failure, the plant would soon experience a low level scram from the redundant unaffected instrument channels and perhaps a high level turbine trip/reactor trip. All of these conflicting indications and automatic actions could hamper timely and correct operator response to such an event. Automatic plant response must be relied upon to terminate and control the transient. This is confirmed by operating experience (see Apendix A) which shows several cases where operators did not respond to such events and automatic protective action was needed to terminate the transient.

If the failure in the instrumentation causes a very gradual decrease in the reference leg level, then actual reactor level could fall to the low level scram setpoint (because of the feedwater control system action) before the false level appearing to level sensors in the failed instrument legs rises to the high level turbine trip setpoint. Low level reactor scram would occur due to actuation of redundant level sensors (LIS 3-203 C&D) on the other instrument lines. Eventually, the spurious high level sensed could cause main and reactor feedwater turbine trips on two-out-of-three coincidence high level from the alarm . its in the feedwater control system. If, on the other hand, the rate of increase of spurious level is faster, a high level trip (two-out-of-three high level) of the main and reactor feedwater turbines (and consequent reactor trip due to main turbine trip) could occur before the vessel level reaches the low level scram setpoint. In either case, the failure would cause a spurious high level to be sensed. The control system would then cause a reduction in the true vessel level, which could require the protective action of low level scram of the reactor.

This interaction between the feedwater control system and the reactor protection system is the safety concern in that the initiating instrument line failure could cause adverse feedwater control system action requiring low vessel level protective actions and, at the same time, would also prevent proper action of certain low level protection system channels.

2:3 The Safety Concern and Related Regulations

General Design Criterion 24 on separation of protection and control systems states, "The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired." In the BWR level instrumentation system, a single failure in the sensing line that causes control system action, does not leave intact a system satisfying all reliability, redundancy and independence requirements for the low vessel level protective function.

IEEE 279-1971 paragraph 4.7.3 on control and protection system interaction states, "Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protective system channel designed to protect against the condition, the remaining redundant protection channels shall be capable of providing the protective action even when degraded by a second random failure." This requirement of IEEE 279 augments the requirement of General Design Criterion 24 on leaving intact a protection system satisfying all reliability, redundancy, and independence requirements of the protection system on failure of any single control system component or channel. IEEE 279-1971 is, however, limited in scope to the protection system devices and circuitry from sensor to actuation device input terminals. NRC has interpreted this to exclude the fluid sensing lines.

Based upon operating experience, we believe that a single random failure in the sensing line should now be considered in implementing IEEE 279-1971. (It is noted that the 1977 and 1980 editions of IEEE Standard 603, which are later versions of IEEE 279-1971, do address the subject of sensing lines and include them as part of the protection system.)

Applying the requirement of paragraph 4.7.3 to the instrumentation system under discussion, the single random failure is the decreasing reference leg level and the resulting control system action is lowering of the actual vessel level, which would require a low level protective action. Two protection channels (LIS 3-203A&B) are prevented from performing their protective actions, leaving redundant channels (LIS 3-203C&D) to provide the required protective function. If a single active failure is now postulated in one of the two remaining channels, then the required automatic protective actions will not occur at the low water level scram setpoint. Further, if one of the four channels is inoperable due to maintenance or required surveillance, and is not placed in a trip condition, then this would tend to exacerbate the safety concern since the single failure of a decreasing reference leg could defeat the associated automatic protective actions at the low water level scram setpoint. Under these conditions the information provided in Section 2.2 of this report continues to be valid and appears to make the concern more significant. However, since the technical specifications allow the level instrument system to remain in this degraded mode (that is, three operable channels and one inoperable non-tripped channel) for a period of up to only two hours this aspect may not be significant in the broader context of the concern.

The above concern can be extended to all designs where the protection system uses a one-out-of-two-twice logic (i.e., A or C and B or D) to initiate protective action. Even if only one protection system channel is coupled to a control system channel (say A), and if the single random failure causes a control system action requiring protective action and also prevents proper action of the protection system channel, a further single active failure of one particular remaining redundant protection system channel (C), will prevent the required protective actions associated with these protection channels.

2.4 Possible Unanalyzed Sequence of Occurrences

Level instrumentation sensor LIS 3-203A through D provide the following protective actions

(1) Scram

(2) Primary containment isolation

(3) HPCI and RCIC turbine trip

(4) Start standby gas treatment system (SBGTS)

When two channels (LIS 3-203A&B) sense a spurious high level and a random failure is postulated in one of the remaining redundant channels (LIS 3-203C or D) the protective actions are affected as follows:

(1) Scram - Low level scram will not occur.

(2) Primary containment isolation due to low level will not occur. (Typically Group 2, 3, and 6 valves are affected.) The following pipelines will not isolate:

- RHR reactor shutdown cooling supply
- RHR reactor head spray
- Reactor water cleanup system
- Drywell equipment drain discharge
- Drywell flow drain discharge
- Drywell purge inlet
- Drywell main exhaust
- Suppression chamber exhaust valve bypass
- Suppression chamber purge inlet
- Suppression chamber main exhaust
- Drywell exhaust valve bypass
- Suppression chamber drain
- RHR flush and drain vent to suppression chamber
- Drywell purge and vent outlet
- Drywell makeup
- Suppression chamber makeup
- Exhaust to SBGTS

However, if isolation of the above pipelines were truly needed, excluding the lines associated with the reactor water cleanup system, it would still be obtained by other diverse means which initiate on high reactor building ventilation exhaust radiation and/or high drywell pressure.

(3) HPCI and RCIC turbines will receive a high level trip signal (when LIS 3-203 A&B, connected to one set of instrument lines, reaches spurious high level of +54 inches, and if either LIS 3-203C or D, connected to the other set of instrument lines, is postulated to fail high).

(4) SBGT system will not receive an automatic start signal.

The event initiated by the instrument line failure will continue and the reactor vessel level will decrease due to reduced or even terminated feedwater flow. If the operator does not take corrective actions, the vessel level will reach the low-low level and the level instrumentation monitoring the accident or wide range, specifically sensors LIS 3-56A thru D, will initiate closure of MSIVs which in turn will cause a reactor scram. Sensors LIS 3-58A through D will sense conditions necessary to initiate HPCI, RCIC, ADS and core spray systems. Scram under these conditions would occur at an actual vessel level which is considerably below the normal low level scram. (Current safety analyses normally assume that a scram occurs directly from the low level instrumentation, which is defeated under these conditions, and not indirectly by the way of MSIVs from the low-low level instrumentation.) Further, when the MSIVs close, this action will tend to collapse the voids contained in the vessel fluid and will further decrease the fluid level in the reactor vessel.

In addition, due to the presence of high level trip interlock signals (item 3 above), automatic operation of HPCI and RCIC would not occur in some designs since the high level trip signal takes precedence over the low-low level start initiation signal. This situation of a decreasing water level in the vessel, coupled with (1) scram which is initiated at a vessel level lower than the normal low level scram, and (2) the unavailability of automatic operation of safety grade high pressure injection systems, appears to be an unanalyzed sequence of occurrences.

A typical scenario initiated by a level instrumentation reference leg failure would be as follows:

> The loss of the reference leg in the normal range level instrumentation causes a spurious increasing level to be sensed by the feedwater control system, leading to a decrease in actual vessel level. By the same failure, two low level protection system channels are disabled. When the vessel level reaches the low level setpoint, reactor scram and primary containment isolation would normally occur due to actuation of redundant low level protection channels on the unaffected instrument lines. A postulated signal failure in the redundant low level protection channels, however, could disable the low level reactor scram. The spurious high level sensed by the instrumentation of the affected instrument line could cause a turbine trip which would, in turn, scram the reactor or, based on the various indications available in the control room and time permitting, an alert operator could initiate manual scram and containment isolation. HPCI and RCIC could be manually started if not locked out by the failed instrumentation. Otherwise, low pressure emergency core cooling would have to be initiated to provide water to the vessel. If no manual action is taken, when low-low vessel level is reached MSIV closure and associated scram will occur. Automatic ECCS actuation will also be initiated.

Based on the availability of these various means of automatically and manually accomplishing the required protective actions, we do not consider the postulated control system protection system interaction precipitated by hydraulic effects an immediate safety concern; however, we do consider that the safety concern needs to be addressed.

3. FINDINGS

(1) The physical arrangement of reactor vessel water level instrumentation in operating BWRs is such that hydraulic coupling exists between sensors that provide input to the feedwater control system and to the plant protection systems. The level instrumentation that monitors the operating range is physically arranged so that sensors which separately provide input to the feedwater control system and to two channels of the reactor protection system and ECCS are connected across common instrument lines.

(2) Certain single failures in the instrument lines can cause a decrease in the reference leg level or affect the variable leg level of the vessel level instrumentation. The ensuing spurious level is sensed by the feedwater control system and two channels of the protection system. The spurious level sensed by the control system could cause the system to respond adversely, resulting in a plant condition requiring protective action.

(3) Moreover, such a failure causing incorrect control system response would also prevent proper action by two of the protection channels. If a random failure is now postulated in one of the remaining redundant two channels, then the protective function will not occur automatically from the normal low level protective instrumentation. This could lead to a plant condition which appears to be unanalyzed.

(4) The operator is presented with conflicting information which may prevent him from taking correct and timely actions.

(5) The situation outlined above suggests that selected BWR level instrumentation systems may not meet the intent of the regulations for operation of protection and control systems single failure criterion as delineated in General Design Criterion 24.

4. CONCLUSION

BWR operating experience has shown that a single failure in an instrument sensing line could affect all level sensors that share the same sensing line. There also have been events where interaction has occurred between control systems and protection systems. Our review of these operating experiences has raised the safety concern of a single failure in the BWR vessel level instrumentation causing a feedwater control system action that could 1) result in a condition requiring protective actions and, at the same time, 2) prevent proper action of the reactor protection system channels designed to protect against such a condition. We also consider that certain level instrumentation configuration in operating BWR's may not fully meet the intent of General Design Criterion 24. Based upon operating experience we believe that a single random failure in the instrument sensing lines should now be considered in implementing IEEE 279-1971. Although we do not consider the postulated control system-protection system interaction an immediate concern we do consider that the safety concern and associated problem need to be addressed.

5. RECOMMENDATIONS

(1) Action should be implemented to assure that automatic and manual safety-related low-low level start and high pressure injection functions of HPCI and RCIC turbines are not prevented or delayed by the non-safety-related high level trip. For example, the control system of HPCI and

RCIC turbines could be modified to provide a low-low level start signal which overr̃ es the high level trip signal.

(2) Action should be implemented to assure that protective functions are provided in spite of any adverse control system-protection system interaction in the narrow range level instrumentation. For example, the protective functions provided by the narrow range level sensors could also be provided by the wide range level sensors (In employing the wide-range level instrumentation, the desired output signal quality in terms of sensitivity, resolution, accuracy and repeatability must be considered to assure that the initiating signals achieve the required protective function.). This approach would be consistent with the concept of "alternate channels" as defined in paragraph 4.7.4.1 of IEEE Standard 279-1971.

(3) Control room operators should be trained to recognize spurious vessel level indications, and procedures should be provided for corrective actions to mitigate the consequences of potential transients that may be caused by level instrumentation malfunctions. We believe that the BWR emergency procedure guidelines provide the best vehicle for the definition of appropriate corrective actions in the event of level instrumentation malfunctions.

APPENDIX A

EVENTS INVOLVING BWR LEVEL INSTRUMENTATION

The events cited are examples of how occurrences involving instrument lines and related items can lead to erroneous vessel level indications. The event descriptions are quoted directly from the Licensee Event Reports and Nuclear Power Experiences.

Plant Name	Date of Event	Event Description
Oyster Creek 1	March 1970	During a surveillance test on the reactor high pressure scram pressure switches, it was observed that the sensing line to the high pressure scram pressure switch had developed a leak at a "Swage-Lok" fitting which caused a level indicator to fail up-scale. An attempt was made to tighten the fitting and the leak increased, causing the excess flow check valve in the primary pressure sensing line to close. The result was a zero pressure signal to the pressure sensors mounted on this rack. (High Pressure Scram, High Pressure Isolation Condenser Actuation, Condenser Low Vacuum Scram By-pass, Core Spray Valve Permissive, Triple Low Level Auto Depressurization, Level Transmitter to Feedwater Control System, Reactor Pressure Indicator Transmitter and Auto Relief Valve Pressure).

Plant Name	Date of Event	Event Description
		Since the Protective Instrument ion Limiting Conditions for Operation could not be met, the operators were notified to prepare for a plant shutdown.
		Subsequently, it was determined that the single failure of this sensing line prevented the operation of both isolation condensers upon receipt of a reactor high pressure signal. Emergency condenser isolation on pipe-break was still operable as was emergency condenser actuation by low-low level and manual operation from the control room. Plans were to determine the wiring modifications necessary to establish the ability of the emergency condensers to operate on a high pressure signal in the event of a loss of a single pressure sensing line. In the meantime, operating personnel were made aware of the situation and reminded that plant emergency procedures call for verification of automatic action and manual initiation of such actions required.
Peach Bottom 2	Sept. 8, 1976	During routine surveillance testing, containment spray permissive switch LIS-2-2-3-72A was

Plant Name	Date of Event	Event Description
		found to be inoperative. Because the redundant B loop was operable and a manual override is provided for this switch, there was no safety hazard. Cracked bellows on a Yarway Model 4418CE level switch.
Millstone 1	Sept. 1973	During a plant startup, a discrepancy of 15 inches was noted between the two independent reactor level sensing columns. The mismatch was such that half of the RPS, ECCS and primary containment isolation system level switches were seeing an indicated level that was higher than the actual level in the reactor. The mismatch could result in late initiation signals for the systems in a situation where a failure occurred in the level switches that were reading properly.
		An investigation revealed a valve that is normally used for filling the system was leaking. The water was being drained from the reference column at a rate greater than the make up rate by condensation in the level column condensing pot. A loss of water from the reference column in a device such as this causes the indicated level to rise.

Plant Name	Date of Event	Event Description
		The valve was replaced and the indicated levels converged such that they were within the requirements of the Technical Specifications.
Monticello 1	July 13, 1975 (75-01T)	During normal operation a small leak developed in a reactor pressure gauge. The leak lowered the reference leg level for the Scram and ECCS initiating Yarway level instruments connected to the same process tap causing incorrect level indication. Redundant Yarways were operable. No previous similar occurrences. Pressure Gauge isolated (AO-50-263/75-12). A leak developed in the Bourdon tube of Heise Model C MM 7646 0-1500 psig pressure gauge.
Brunswick 2	May 1976	During start up a level indicating switch (Yarway) malfunctioned due to an internal leak. The associated instrument channel was manually tripped. The cause of the occurrence was the threaded pipe inside the instrument housing leaked because of a crossed thread.
Browns Ferry 2	Aug. 14, 1977 (LER 77-03L)	During start up from Cold Shutdown, reactor water column "B" reference leg was low, producing a +20 inch error in two reactor water

Plant Name	Date of Event	Event Description
		low-level scram switches. Redundant switches were operable and in service. The reference leg was refilled and water level agreement confirmed. This was not a repetitive problem. The integrity of all sensing lines and valves external to the drywell was confirmed. The apparent cause was either evaporation of water from the reference leg during cold shutdown, or inadvertent operation of equalizer or drain valves.
Cooper	Jan. 1976	Cold shutdown. While maintenance was being performed in the drywell, a rusty spot was noticed on some insulation close to the reactor. Upon further investigation, it was determined that a crack in the two inch instrument sensing line on vessel penetration N-11A had developed outside the safe end weld, in the heat affected zone (HAZ) 1/2 inch from the weld center. History of this weld showed the original weld failed the RT and was cut out and rewelded. The second weld failed the RT and was repaired. The third weld passed the RT.

Plant Name	Date of Event	Event Description
		The failure was the result of material failure in the HAZ of the two inch schedule 80 ASTM-A-312 GRTP-304 Stainless steel pipe. This instrument tap fed the low leg of the scram and primary containment isolation level switches, auto blowdown permissive level switches, reactor feedwater control and wide range level indications.
Cooper	Dec. 1977	While at 75% power, during a plant tour, it was noted that three reactor level instruments were reading high upscale. Further investigation revealed that the instrument line excess flow check valve was leaking around the body nut. The leak at the valve caused the condensing chamber and reference leg level to decrease, thus causing instruments associated with that sensing line to read upscale.
Brunswick 2	March 1978	Technicians were performing a test while at 97% power (reactor water level inside shroud) on a Yarway instrument when the main turbine and feedwater pump turbines tripped, causing a reactor scram.

Plant Name	Date of Event	Event Description
		The scram occurred as a result of a pressure change in the common level instrument reference leg which apparently actuated the NOO4 instruments. The pressure change apparently occurred due to the bellows movement in the instrument being calibrated. No personnel error was detected. They were shutdown for 25 hours. An investigation was to be performed to determine the most suitable instrument arrangement and test procedures necessary to prevent reference leg pressure changes. The investigation was to consist of an industrial survey and a design review.
Dresden 2	May 1979	During start up the main turbine tripped on high water level. It was discovered that a packing leak existed on the isolation valve for the local pressure indication, PS-263-60B. The "B" reference leg drained to an abnormally low level through the packing leak. This resulted in an upscale reading on all the Yarways on instrument rack 2206. The "B" reference leg root valve was shut to isolate the leak which isolated the following components:

Plant Name	Date of Event	Event Description
		PS-263-55C, 55D, LIS-263-58A, 58B, 72B, 72D, and LITS-263-59B. A control systems technician locally isolated PI-263-60B (local pressure indication) and PS-263-55D (reactor high pressure scram) via their common sensing line root valve. The "B" reference leg root valve was then opened and the reference leg filled. Since the Technical Specifications require two instrument channels per trip system, an orderly reactor shutdown was begun immediately. The packing was tightened and subjected to a hydro of 1000 psi. No leaks were discovered. The isolation valves for PS-263-55D and PI-263-60B were opened and the common sensing line root valve was opened, returning the system to normal.
Monticello 1	Sept. 23, 1979 (LER 79-019/03L-0)	During normal operation a leak developed in a reactor pressure gauge. The leak lowered the reference leg of the scram and ECCS Yarway level switches connected to the same process tap. As a result, the Yarways indicated a false high level and would not have tripped within the settings specified in sections 3.1.1 and 3.2.3 of Technical Specifications.

Plant Name	Date of Event	Event Description
		Redunda t level instruments were operable. One previous similar occurrence reported in AO 50-263/75-12. Pressure gauge is Heise Model C, 8 1/2 inch dial, 0-1500 psig, 403 Stainless Steel Bourdon Tube. Small crack discovered in Bourdon Tube, most probable cause is fatigue. Gauge isolated and removed. New gauge with wide range and improved Bourdon tube material to be installed on different process tap.
Brunswick 1	May 8, 1980 (LER 80-048/03L-0)	During normal surveillance, the cap covering the calibration adjustment screw on reactor level instrument, 1-B21-LIS-N031B, was leaking water. The leak was repaired and Pressure Test 3.1.7PC, Reactor low level #2 and #3 calibration and functional test was performed on the instrument Switch #2 of the instrument would not actuate. The reportable limit is >194.53 inches applied water. This event did not affect the health and safety of the public. The calibration adjustment screw cap gasket was replaced, the contacts of switch #2 were cleaned. Pressure Test 3.1.7 PC was performed satisfactorily and the instrument was returned to service.

Plant Name	Date of Event	Event Description
Fitzpatrick 1	Nov. 3, 1980 (LER 80-084/03L-0)	During normal operation while conducting surveillance to satisfy Technical Specifications Table 4.1-1, reactor water level switch 02-3-LIS-101B or 101D was found less conservative than allowed by Technical Specification Table 3.1-1 on three occasions between 11/3/80 and 11/25/80. Redundant level switches were within Technical Specification limits and in each case the level switches were immediately recalibrated to within its limits. No significant hazard existed. See attachment for additional details. Probable cause was personnel error which resulted in the introduction of air in level sensing line. Back flushing of sensing lines to remove air eliminated problem. Review of procedure does not indicate need for change.
Brunswick 1	Jan. 20, 1981 (LER 81-016/03L)	During normal plant operation reactor instrument penetration (RIP) valve, X-53C, shut with a Control Air Supply Failure Alarm, and isolated the variable leg to reactor level instruments B 21-LIS-N017A and B 21-LI-3331, which resulted in a reactor scram on low level. This event did not affect the health or safety of the public.

Plant Name	Date of Event	Event Description
		An exhaustive investigation failed to reveal a definite cause for the RIP valve closure. This investigation included a leak check on the valve control air supply, a timed leak check of the valve bellows and a visual inspection of the valve and the valve high flow isolation switch. This is considered an isolated event, as system air pressure was normal and no other valves isolated.
Browns Ferry 2	March 31, 1981 (RO 50-260/81014)	During normal operations while decreasing load for M/G set maintenance, the Reactor Water Level Instrumentation indicated full upscale resulting in a turbine trip. There was no hazard to the health or safety of the public. Instruments affected were: 2-LITS-3-52; 2-LIS-3-203A, B; 2-LIS-3-184. The technical specifications were fully complied with at all times. Equalizing valve, on 2-LITS-3-52 was partially open. Closed equalizing valve, verified reactor water instruments operable.
Browns Ferry 3	May 25, 1981 (LER 81-027/03L-0)	During startup, following a maintenance outage, reactor water level instrumentation 3-LIS-3-203A and B indicated full upscale and were declared inoperable. There was no danger to the health and safety of the public. Redundant systems were available and operable.

Plant Name	Date of Event	Event Description
		Reference leg was los. on the water column for undetermined reasons, causing the Barton model 288 A, bellows type indicating switch, to indicate full upscale. The water leg was backfilled and the instruments returned to operable status.
Oyster Creek	Sept. 5, 1981 (LER 81-36/03L)	On September 5, 1981 at approximately 0100 hours while performing a flush of Core Spray System I piping, one reactor water level indicator showed a high level while all other level indicators remained stable and in agreement. The flush in progress was immediately terminated and an investigation was initiated to determine the cause of the high level indication. It was found that the instrument reference leg was not filled with water which caused an erroneous high level reading on the instrument in question. The failure of this instrument resulted in the loss of one of two level instrument channels in each of two level instrument systems. It should be noted that there are no piping connections between the Core Spray System and the affected water level instrumentation reference leg. This

Plant Name | Date of Event | Event Description

was confirmed by a hand over hand walkdown of the reference leg piping.

The cause of the decrease in reference level head could not be determined. There is no connection which can be inferred between the loss of reference leg and the flush evolution.

The reactor water level instrument in question provides various Reactor Protection Safeguard System functions associated with Reactor Scram, Core Spray initiation, Isolation Condenser initiation and ATWS Recirc Pump Trip. Since redundant instrumentation, which was operable, also provides these functions and since the Reactor was shutdown, vented, and less than 212°F, the safety significance of this event is considered minimal. Additionally, it should be noted that no change in actual reactor water level occurred as a result of this event.

The reference leg for the affected level instrument was backfilled with condensate which restored it to an operable condition. A hand over hand walkdown of the Reference Leg System for proper configuration together

Plant Name	Date of Event	Event Description
		with a check of the instrument connected to the reference leg for leakage was performed with no abnormalities noted.

(The following event-description is taken from the INPO-NSAC Analysis and Evaluation Report of April 1981 on "High Pressure Core Cooling System Malfunction at Hatch 1.")

Hatch 1	June 26, 1980	At 6:49 am, on June 26, 1980, Hatch-1 was operating at 99.4% of rated power. Operating conditions appeared normal. Reactor pressure indicated 990 psig. Both reactor feedwater pumps, and both reactor recirculation pumps were running. The reactor water level was normal at about +37 inches.
		At 6:49:09 am, the GEMAC A and C reactor water level channels signaled that the level had quickly risen to +58 inches. With 2 of the 3 GEMAC channels indicating a high level, a number of automatic actions occurred. The reactor feedwater pumps and the turbine/generator were tripped. Subsequently, the reactor scrammed.
		There are three GEMAC transmitters of reactor water level connected to 2 separate hydraulic systems that sense reactor water level. The

Plant Name	Date of Event	Event Description
		GEMAC A and C channel transmitters are connected to one of the hydraulic systems. Two Barton transmitters are also connected to this same hydraulic system. The GEMAC B channel transmitter, and two other Barton transmitters, are connected to the other hydraulic system that senses reactor level.

Only the GEMAC A and C channels signaled high reactor water level. The GEMAC B channel did not signal a high level. Moreover, one second after the GEMAC A and C channels picked-up on high water level, 2 Barton transmitters signaled low reactor water level at +12.5 inches. Within 4 seconds, all four Barton channels signaled that the reactor water was at +12.5 inches. Summarizing, GEMAC channels A and C said the water level in the reactor was high, and 4 other channels said it was low.

Within 2 seconds after the start of the event, four channels indicated that the reactor pressure had risen to 1045 psig. Within 4 seconds, four Barton transmitters signalled a low reactor water level and triggered the isolation of some of the reactor support systems. Increased system

Plant Name	Date of Event	Event Description
		pressure and a decreased reactor water level are anticipated responses to a total loss of feedwater and turbine/generator trip. Within 16 seconds, safety/relief valve operation, combined with the operation of the turbine steam bypass systems, had brought the pressure down to 1030 psig. With the decreased pressure, increased void formation caused the reactor water level to rise several inches and by 29 seconds, the reactor low water level had cleared, indicating that the reactor water level had recovered to at least +15 inches.
		Thirty nine seconds after the event began, all four Barton channels alarmed a second time, indicating that the reactor water level had again dropped below +12.5 inches. The GEMAC channels showed similar levels. The reactor pressure was now steady at about 890 psig.
		At 47 seconds, a signal was received that closed the main steam line isolation valves. All but one of the closure signals are alarmed on the computer. The low reactor water level (-38") closure signal is not

Plant Name	Date of Event	Event Description
		alarmed. None of the computer alarms associated with the closure signals were activated. This indicated that the low reactor water level closure signal was the most likely source of the MSIV closure and that reactor water level had dropped to -38".

At 95 seconds a feedwater pump was started, but because the main steam line isolation valves had been closed, the pump ran for only about 10 seconds. The HPCI turbine received a signal to start automatically. However, the initial high flow of steam to the turbine caused an instrument that monitors for high steam line flow (symptom of a steam pipe break), to activate erroneously and close the two containment isolation valves in the steam line to the HPCI turbine. The HPCI turbine ran momentarily and stopped.

During this period, operators also were attempting to start the RCIC system. However, the RCIC system would not start and continue to run. It remained inoperable throughout the event.

Plant Name | Date of Event | Event Description

Operators reset the HPC. ystem isolation signal that had been triggered by the high steam flow surge on the initial startup attempt. They then opened the inboard isolation valve in the HPCI turbine steam supply line, while leaving the outboard valve closed. But again, for reasons unknown, an additional isolation signal activated, calling for closure of the closed outboard valve. Operators then closed the inboard valve.

At three minutes into the event the following conditions existed: The main steam line isolation valves were closed. There was no feedwater supply to the reactor. Heat had been generated in the reactor faster than it was removed. The reactor pressure had risen to approximately 1100 psig and was being controlled by the safety/relief valves. The steam was now removing the decay heat to the suppression pool.

About 5 minutes after the event began, the operators tried a different HPCI turbine start-up strategy. They closed the HPCI turbine steam supply valve. This valve

Plant Name	Date of Event	Event Description
		is located downstream of the two isolation valves and upstream of the HPCI turbine stop and control valve. They then reset the isolation signal that had occurred during the previous start attempt, and opened the inboard and outboard isolation valves. The isolation signal was cleared, and with a low reactor water level signal still present, the HPCI steam supply valve opened automatically. The HPCI turbine started, and supplied water to the reactor vessel. Seven and one-half minutes after the event began, the water level in the reactor was again close to normal.

ATTACHMENT 4

SP29.023.02
Common Level Control

(Section Head)

(Plant Manager)

SP Number 29.023.01 Reg. #31

Revision F

Effective Date

LEVEL CONTROL

EMERGENCY PROCEDURE

1.0 PURPOSE

The purpose of this procedure is to restore and stabilize RPV water levels.

2.0 ENTRY CONDITIONS

The entry conditions for this procedure are any of the following:

2.1 RPV water level less than 12.5"

2.2 Drywell pressure greater than 1.69 psig

2.3 An isolation condition exists which requires OR initiates reactor scram.

3.0 OPERATOR ACTIONS

3.1 Confirm initiation of the following. Initiate any of the actions which should have initiated but did not.

_____ 3.1.1 VERIFY reactor scram

AND

PERFORM SP 29.010.01, (Emergency Shutdown), concurrently with this procedure.

_____ 3.1.2 VERIFY group isolations consistent with entry conditions.

3.1.2 Ref. technical specification 3/4.3.2

_____ 3.1.3 VERIFY automatic initiation of ECCS systems consistent with entry conditions.

3.1.3 Ref. technical specification 3/4.3.3

______ 3.1.4	VERIFY diesel generators start consistent with entry conditions.	3.1.4 Diesel generators start at 1.69 psig OR -132.5"
3.2	Restore and maintain RPV water level between 12.5" and 34.5" with one or more of the following systems:	3.2 NOTE The choice of using the following systems vary with plant conditions. It is preferred that the minimum number of systems be used to accomplish water level restoration.
______ 3.2.1	Condensate/Feedwater	3.2.1 Press range 1115 to Ø psig (Ref. SP 23.1Ø9.Ø1)
______ 3.2.2	CRD	3.2.2 Press range 1115 to Ø psig (Ref. SP 23.1Ø6.Ø1)
______ 3.2.3	RCIC	3.2.3 Press range 1115 to 57 psig (Ref. SP 23.119.Ø1)
______ 3.2.4	HPCI	3.2.4 Press Range 1115 to 110 psig (Ref. SP 23.2Ø2.Ø1)
______ 3.2.5	C.S.	3.2.5 Press Range 333 to Ø psig (Ref. SP 23.2Ø3.Ø1)
______ 3.2.6	LPCI	3.2.6 Press Range 238 to Ø psig (Ref. SP 23.2Ø4.Ø1)
______ 3.3	IF RPV water level cannot be restored AND maintained above +12.5" THEN maintain RPV water level above top of active fuel	3.3 NOTE TAF = +6" as read on fuel zone instrumentation LI-ØØ7.

_______ 3.4 IF RPV water level cannot be maintained above TAF

OR

cannot be determined,

THEN proceed to SP 29.Ø23.Ø4 (Level Restoration).

3.4 NOTE
TAF = +6" as read on fuel zone instrumentation LI-[illegible].

_______ 3.5 Notify the Watch Engineer to classify the event and initiate the Emergency Plan as required.

3.5 Ref. SP 69.Ø1Ø.Ø1

_______ 3.6 IF RPV water level can be restored

AND

maintained above 12.5"

AND

it is determined that an emergency does not exist,

THEN proceed to the appropriate station procedure as determined by Shift Supervision.

_______ 3.7 IF SRV's are cycling,

THEN open one SRV and reduce RPV pressure to between 8ØØ and 960 psig.

_______ 3.8 WHEN the RPV water level has stabilized above TAF,

THEN proceed to SP 29.Ø23.Ø2 (Cooldown).

4.0 REFERENCES

4.1 SP 29.Ø1Ø.Ø1 Emergency Shutdown

4.2 SP 29.Ø23.Ø2 Cooldown

4.3 SP 29.Ø23.Ø4 Level Restoration

4.4 SP 23.1Ø3.Ø1 Condensate

4.5 SP 23.1[illegible].01 Feedwater

4.6 SP 23.119.01 Reactor Core Isolation Cooling System

4.7 SP 23.202.01 High Pressure Coolant Injection

4.8 SP 23.203.01 Core Spray System

4.9 SP 23.204.01 Low Pressure Coolant Injection

4.10 SP 23.106.01 Control Rod Drive

4.11 Technical Specifications, Section 3/4.3.2

4.12 Technical Specifications, Section 3/4.3.3

4.13 SP 69.010.01 Conditions for Emergency Action Levels

ATTACHMENT 5

SP29.023.04
Level Restoration

APR 06 1982

Submitted: ____________________

Approved: ____________________
(Plant Manager)

SP Number 29.023.04

Revision F

Effective Date ____________

LEVEL RESTORATION

EMERGENCY PROCEDURE

1.0 PURPOSE

The purpose of this procedure is to restore RPV water level to above top of active fuel.

2.0 ENTRY CONDITIONS

Enter this procedure from SP 29.023.01 (Level Control) or SP 29.023.02 (Cooldown) when RPV water level cannot be maintained above top of active fuel (TAF = +6" as read on fuel zone instrumentation LI-007).

3.0 OPERATOR ACTIONS

3.1 Lineup for injection and start pumps in at least two of the following normal injection subsystems:

_____ 3.1.1 CS A — 3.1.1 Ref. SP 23.203.01 (Core Spray System)

_____ 3.1.2 CS B — 3.1.2 Ref. SP 23.203.01 (Core Spray System)

_____ 3.1.3 LPCI A — 3.1.3 Ref. SP 23.204.01 (Low Pressure Coolant Injection)

_____ 3.1.4 LPCI B — 3.1.4 Ref. SP 23.204.01 (Low Pressure Coolant Injection)

_____ 3.1.5 Condensate — 3.1.5 Ref. SP 23.103.01 (Condensate System)

3.2 IF less than two normal injection subsystems (Paragraph 3.1) can be lined up,

THEN line up as many of the following alternate injection subsystems as possible

BUT

DO NOT inject:

Rev. #5-9

_____ 3.2.1 Reactor Building Service Water System through service water/recirc loop ultimate cooling water crosstie valves 1P41-MOV-Ø33A, MOV-Ø33B, MOV-Ø33C, and MOV-Ø33D.

3.2.1 Ref. SP 23.122.Ø1 (Service Water)

_____ 3.2.2 ECCS connections from the Condensate Transfer System

3.2.2 Ref. SP 23.1Ø5.Ø1 (Condensate Storage and Transfer)

_____ 3.2.3 SLC (test tank or boron tank)

3.2.3 Ref. SP 23.123.Ø1 (Standby Liquid Control)

_____ 3.3 IF at any time water level cannot be determined

THEN proceed as follows.

_____ 3.3.1 IF no system

OR

normal injection subsystem is lined up for injection with at least one pump running

THEN start pumps in alternate injection subsystems which are lined up for injection.

_____ 3.3.2 IF no system

OR

normal injection subsystem

OR

alternate injection subsystem is lined up for injection with at least one pump running

THEN proceed to section 3.8.6 Core Cooling without injection

3.3.3 IF a system

OR

normal injection subsystem

OR

alternate injection subsystem is lined up for injection with at least one pump running,

THEN proceed to SP 29.023.05, Rapid RPV Depressurization

_____ 3.4 MONITOR RPV pressure

AND

water level,

THEN proceed at the step indicated in the following table.

3.4 NOTE

IF at any time the RPV water level trend reverses or RPV pressure changes region,

THEN return to step 3.4.

Table 1

RPV PRESSURE REGION

	333 HIGH	333 to 110 INTERMEDIATE	110 LOW
RPV LEVEL INC.	3.5	3.6	3.7
RPV LEVEL DEC.	3.8	3.8	3.9

3.5 RPV level increasing and RPV pressure greater than 333 psig (High Region)

3.5.1 ENTER SP 29.023.01 (Level Control) at Step 3.2.

3.6 RPV level increasing and RPV pressure between 333 and 110 psig (intermediate region)

CAUTION

Do not depressurize the RPV below 110 psig unless motor driven pumps sufficient to maintain RPV water level are running and the sy_ ems are available for injection.

_____ 3.6.1 IF HPCI and RCIC are not available

AND

RPV pressure is increasing,

THEN ENTER SP 29.023.05 (Rapid RPV Depressurization)

_____ 3.6.2 IF HPCI and RCIC are not available

AND

RPV pressure is not increasing,

THEN ENTER SP 29.023.01 (Level Control) step 3.2.

_____ 3.6.3 IF HPCI

OR

RCIC are injecting

AND

RPV water level increases to +12.5",

THEN ENTER SP 29.023.01 (Level Control) Step 3.2.

3.7 RPV level increasing and RPV pressure less than 110 psig (low region)

______ 3.7.1 IF RPV pressure is increasing,

THEN ENTER SP 29.023.05 (Rapid RPV Depressurization)

______ 3.7.2 IF RPV pressure is not increasing,

THEN ENTER SP 29.023.01 (Level Control) step 3.2.

3.8 RPV level decreasing and RPV pressure greater than 110 psig (Intermediate/High region).

____ 3.8.1 IF HPCI and RCIC are not operating,

THEN restart HPCI

AND

RCIC

3.8.1 Ref. SP 23.202.01 (High Pressure Coolant Injection)

RCIC - Ref. SP 23.119.01 (Reactor Core Isolation Cooling System)

____ 3.8.2 IF CRD is not operating

AND

at least 2 normal injection subsystems are lined up for injection with pumps running,

THEN ENTER SP 29.023.05 (Rapid RPV Depressurization).

____ 3.8.3 IF CRD is not operating

AND

no normal injection subsystem is lined up for injection with at least one pump running,

THEN start pumps in the following alternate injection subsystems which are lined up for injection.

____ (A) Reactor Building Service Water System through service water/recirc loop ultimate cooling water crosstie valves 1P41-MOV-033A, MOV-033B, MOV-033C, and MOV-033D.

(A) Ref. SP 23.122.01 (Service Water)

(B) ECCS connections from the Condensate Transfer System

(B) Ref. SP 23.1Ø5.Ø1 (Condensate Storage and Transfer)

(C) SLC (test tank or boron tank)

(C) Ref. SP 23.123.Ø1 (Standby Liquid Control)

3.8.4 WHEN RPV water level drops to TAF

THEN perform step 3.8.5

OR

step 3.8.6.

3.8.4 NOTE
TAF = +6" as read on fuel zone instrumentation LI-007.

3.8.5 IF a system

OR

normal injection subsystem

OR

alternate injection subsystem is lined up for injection with at least one pump running

THEN proceed to SP 29.Ø23.Ø5 (Rapid RPV Depressurization)

3.8.6 IF no system

OR

normal injection subsystem

OR

alternate injection subsystem is lined up for injection with at least one pump running,

THEN perform Core Cooling without injection as follows.

(A) IF at any time any system

OR

normal injection subsystem

OR

alternate injection subsystem is lined up for injection with at least one pump running,

THEN proceed to SP 29.Ø23.Ø5 (Rapid RPV Depressurization).

(B) WHEN RPV water level drops to (Later) (2/3 core height)

OR

IF RPV water level cannot be determined

THEN open one SRV.

(C) WHEN RPV pressure drops below (later), OPEN all ADS valves.

(D) IF all ADS valves cannot be opened,

THEN open other SRV's until a total of 7 valves are open.

3.9 RPV level decreasing and RPV pressure less than 110 psig (low region).

3.9.1 IF no normal injection system is lined up for injection with at least one pump running,

THEN start pumps in the following alternate injection subsystems which are lined up for injection.

(A) Reactor Building Service Water System through service water/ recirc loop ultimate cooling water crosstie valves 1P41-MOV-Ø33A, MOV-Ø33B, MOV-Ø33C, and MOV-Ø33D.

(A) Ref. SP 23.122.Ø1 (Service Water)

(B) ECCS connections from the Condensate Transfer System

(B) Ref. SP 23.105.Ø1 (Condensate Transfer and Storage)

(C) SLC (test tank or boron tank)

(C) Ref. SP 23.123.Ø1 (Standby Liquid Control)

3.9.2 IF RPV pressure is increasing,

THEN proceed to SP 29.Ø23.Ø5 (Rapid RPV Depressurization).

3.9.3 IF RPV pressure is not increasing,

AND

RPV water level drops to TAF

THEN perform Core Cooling without Level Restoration as follows:

3.9.3 NOTE
TAF = +6" as read on fuel zone instrumentation LI-007.

CAUTION

NPSH requirements for pumps taking a suction from the Suppression Pool require a minimum level of 14 feet.

CAUTION

Cooldown rates greater than 100°F/hr may be required to accomplish step (A).

______ (A) Open all ADS valves.

______ (B) IF not all of the ADS valves can be opened,

THEN open other SRV's until a total of 7 valves are open.

______ (C) Operate CS subsystems with suction from the suppression pool.

______ (D) WHEN at least one core spray subsystem is operating with suction from the suppression pool

AND

RPV pressure is less than 290 psig,

THEN terminate injection into the RPV from sources external to the primary containment.

(E) IF RPV water level is restored to TAF

THEN ENTER SP 29.023.01 (Level Control) step 3.?.

(E) NOTE
TAF = +6" as read on fuel zone instrumentation LI-007.

4.0 REFERENCES

4.1 SP 29.023.05 Rapid RPV Depressurization

4.2 SP 29.023.01 Level Control

4.3 SP 23.202.01 High Pressure Coolant Injection

4.4 SP 23.119.01 Reactor Core Isolation Cooling (RCIC) System

4.5 SP 23.106.01 Control Rod Drive

4.6 SP 29.023.09 RPV Flooding

4.7 SP 23.203.01 Core Spray System

4.8 SP 23.123.01 Standby Liquid Control

4.9 SP 23.204.01 Low Pressure Coolant Injection

4.10 SP 23.103.01 Condensate System

4.11 SP 23.105.01 Condensate Storage and Transfer System

4.12 SP 23.109.01 Feedwater System

4.13 SP 23.122.01 Service Water

ATTACHMENT 6

SP29.023.09
Reactor Pressure Vessel Flooding

Approved: ______________________
(Plant Manager)

SP Number 29.023.09

Revision C

Effective Date ________

REACTOR PRESSURE VESSEL FLOODING

EMERGENCY PROCEDURE

DRAFT

1.0 PURPOSE

The purpose of this procedure is to flood the RPV using all the available injection subsystems.

2.0 ENTRY CONDITIONS

This procedure is entered from SP 29.Ø23.Ø5 (Rapid RPV Depressurization) if any of the following occur:

2.1 Temperature near the cold reference leg instrument vertical runs exceeds the RPV saturation limit.

2.2 RPV water level cannot be determined.

2.3 Suppression chamber pressure exceeding pressure suppression limit.

3.0 OPERATOR ACTIONS

______ 3.1 IF at least 3 SRV's are open,

THEN close the following isolation valves.

______ 3.1.1 MSIV's

1B21-AOV-Ø81A
1B21-AOV-Ø81B
1B21-AOV-Ø81C
1B21-AOV-Ø81D
1B21-AOV-Ø82A
1B21-AOV-Ø82B
1B21-AOV-Ø82C
1B21-AOV-Ø82D

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______ 3.1.2 MSL Drain Line Isolation Valves

1B21 MOV-Ø38
1B21 AOV-Ø88

1B21 MOV-Ø33
1B21 AOV-Ø89

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_______ 3.1.3 RHR Steam Condensing Isolation Valve

1E11 MOV-Ø49

_______ 3.1.4 HPCI Isolation Valves

1E41 MOV-Ø41
1E41 MOV-Ø42
1E41 MOV-Ø47
1E41 MOV-Ø48

_______ 3.1.5 RCIC Isolation Valves

1E51 MOV-Ø41
1E51 MOV-Ø42
1E51 MOV-Ø47
1E51 MOV-Ø48

_______ 3.1.6 RWCU Isolation Valves

1G33*MOV-Ø31
1G33*MOV-Ø32
1G33*MOV-Ø41

_______ 3.2 IF RPV water level cannot be determined,

THEN commence injection into the RPV with all of the following systems until at least 3 SRV's are open

AND

RPV pressure is not decreasing

AND

RPV pressure is at least 1ØØ psig above suppression chamber pressure.

_______ 3.2.1 C.S.

3.2.1 Ref SP 23.2Ø3.Ø1 (Core Spray)

_______ 3.2.2 Condensate

3.2.2 Ref SP 23.1Ø3.Ø1 (Condensate)

_______ 3.2.3 LPCI

3.2.3 Ref SP 23.2Ø4.Ø1 (Low Pressure Coolant Injection)

3.2.5 Reactor Building Service Water system through service water/recirc loop ultimate cooling water crosstie valves 1P41-MOV-033A, MOV-033B, MOV-033C and MOV-033D

3.2.4 Ref SP 23.106.01 (Control Rod Drive)

3.2.5 Ref SP 23.122.01 (Service Water)

3.2.6 ECCS connections from the condensate transfer system

3.2.6 Ref SP 23.105.01 (Condensate Storage and Transfer)

3.2.7 SLC (Test tank or boron tank)

3.2.7 Ref SP 23.123.01 (Standby Liquid Control)

3.3 Maintain RPV pressure at least 100 psig above suppression chamber pressure by throttling injection.

3.3 Throttle injection on on subsystems injecting into the RPV

3.4 IF RPV water level can be determined,

THEN commence injection into the RPV with the following systems until RPV water level is increasing.

3.4.1 C.S.

3.4.1 Ref SP 23.203.01 (Core Spray)

3.4.2 Condensate

3.4.2 Ref SP 23.103.01 (Condensate)

3.4.3 LPCI

3.4.3 Ref SP 23.204.01 (Low Pressure Coolant Injection)

3.4.4 CRD

3.4.4 Ref SP 23.106.01 (Control Rod Drive)

3.4.5 Reactor Building Service water through service water/recirc loop ultimate cooling water crosstie valves 1P41-MOV-033A, MOV-033B, MOV-033C, and MOV-033D

3.4.5 Ref SP 23.122.01 (Service Water)

DRAFT

3.4.6 ECCS connections from the condensate transfer systems

3.4.6 Ref SP 23.1Ø5.Ø1 (Condensate Storage and Transfer)

3.4.7 SLC (Test tank or boron tank)

3.4.7 Ref SP 23.123.Ø1 (Standby Liquid Control)

3.5 IF suppression chamber pressure cannot be maintained below the primary containment pressure limit (Fig. 2)

THEN initiate the following systems irrespective of whether adequate core cooling is assured:

3.5.1 Drywell sprays

3.5.2 IF suppression pool water level is below (later)

THEN initiate suppression pool sprays

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CAUTION
Defeating isolation interlocks may be required to accomplish the Step 3.6.

3.6 IF suppression chamber pressure exceeds the primary containment pressure limit (Fig. 2),

THEN vent the primary containment to reduce pressure below the primary containment pressure limit.

3.6 Refer to SP (Later)

determined,

THEN fill all RPV level instrumentation reference columns

AND

Continue injection until temperature near the cold reference leg vertical runs is below 212°F

AND

RPV water level instrumentation is available

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______ 3.8 IF it, can be determined that the RPV is filled

OR

IF RPV pressure is at least 100 psig above suppression chamber pressure,

THEN terminate all injection into the RPV

AND

Reduce RPV water level until level is indicated on two separate level indications.

______ 3.9 IF RPV water level indication is not restored within the maximum acceptable core uncovery time (Fig. 1) after commencing termination of injection into the RPV,

THEN return to step 3.7

determined,

AND

suppression chamber pressure can can be maintained below the primary containment pressure limit (Fig. 2),

THEN enter SP 29.023.01 (Level Control) step 3.2.

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4.0 REFERENCES

4.1 SP 29.023.01 Level Control

4.2 SP 23.106.01 Control Rod Drive

4.3 SP 23.203.01 Core Spray System

4.4 SP 23.123.01 Standby Liquid Control

4.5 SP 23.204.01 Low Pressure Coolant Injection

4.6 SP 23.103.01 Condensate System

4.7 SP 23.105.01 Condensate Storage and Transfer System

4.8 SP 23.122.01 Service Water

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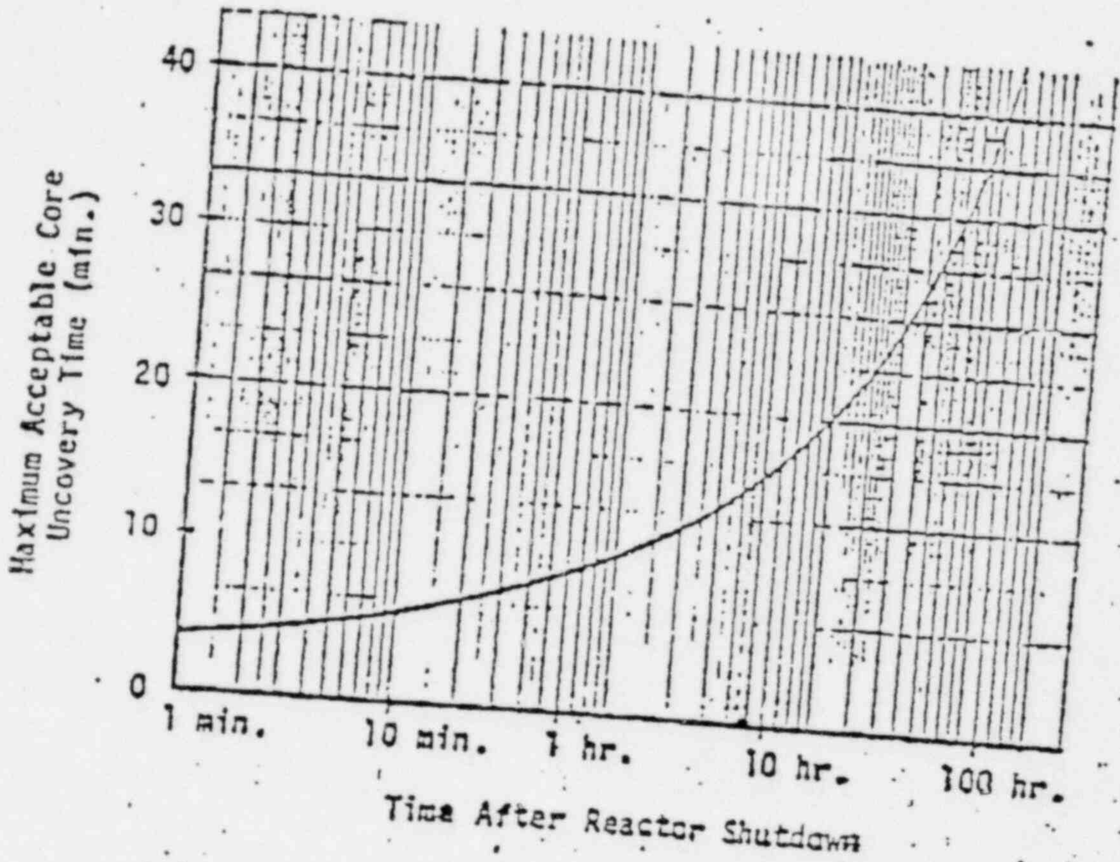

FIG 1

SAMPLE

FIG WILL BE AVAILABLE WHEN THE CALCULATIONS ARE COMPLETE

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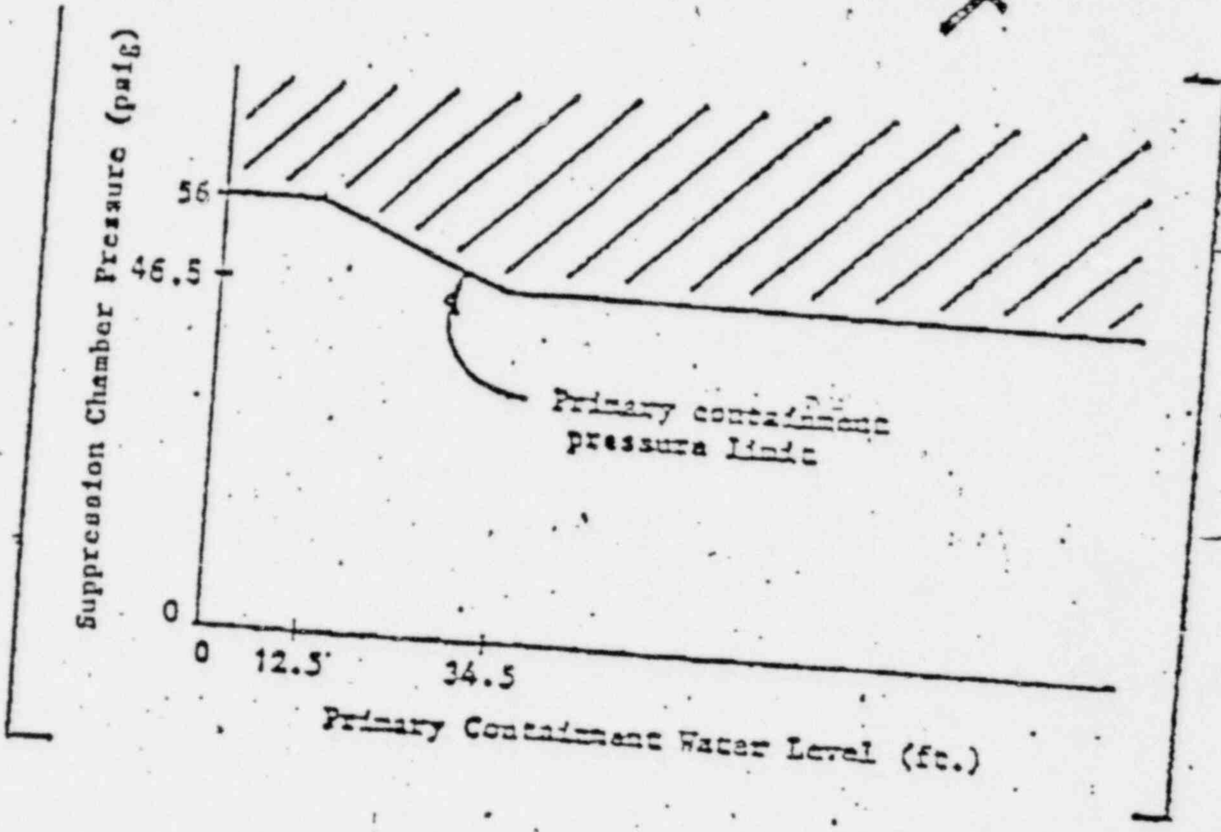

FIG 2

SAMPLE:
FIG WILL BE AVAILABLE WHEN THE CALCULATIONS ARE COMPLETE.

ATTACHMENT 7

NRC Letter, Eisenhut to Denton
(September 11, 1981)

Board
Part 8 - 7

SEP 11 1981

8

MEMORANDUM FOR: Harold R. Denton, Director
Office of Nuclear Reactor Regulation

FROM: Darrell G. Eisenhut, Director
Division of Licensing

SUBJECT: AEOD PRELIMINARY REPORT - SAFETY CONCERN ASSOCIATED WITH REACTOR VESSEL LEVEL INSTRUMENTATION IN BOILING WATER REACTORS, DATED SEPTEMBER 1981

We, inconjunction with DSI, have performed a preliminary review of the subject report to determine the immediacy of its safety concern. We agree with the conclusion of the report that its postulated control system-protection system interaction is not an immediate concern. The report will be distributed by ORAB to the various technical divisions of NRR for further review; and comments will be provided AEOD within 30 days as requested by AEOD.

The AEOD concern is related to the arrangement of the reactor vessel level instrumentation for at least some of the BWR's. Although based upon specific plant designs, the evaluation is general and makes no attempt to identify the specific reactors that would be prone to the concern. Essentially, the report addresses interactions among the feedwater control, reactor protection, primary containment isolation and emergency cooling systems. The sensors used for these systems are arranged in a relatively complex manner such that there are common sensing lines to these sensors. A failure of the instrument lines due to instrument line break, leakage, or an open valve, etc. could result in erroneous signals from both the control and protective systems.

Plant operating experience was reviewed by AEOD and failures such as valve mispositioning were identified. The reported operating events did not result in complete loss of function. However, in the scenario described in the report, the occurrence of a single failure in the unaffected redundant channels would result in decreasing reactor water level, due to reduced feedwater flow, and tripping of the HPCI and RCIC pumps and also loss of direct reactor scram on low reactor water level. In addition, some reactor level instrumentation would provide erroneous indications in the control room, possibly confusing the reactor operations.

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DATE ▶							

The conclusion of the report, although preliminary, is essentially that there is interaction between the feedwater control system and the reactor protection system because of the commonality of the instrument lines of both systems. Therefore, the level instrumentation configuration in operating BWR's may not fully meet GDC 24 and IEEE 279.

We will evaluate this aspect of the design in our continuing review of the preliminary AEOD report; however, we do not consider this an immediate concern because it appears that for the postulated scenarios it would take at least two failures to cause a control-protection system interaction and loss of functional capability of the reactor protection system. In addition if such an event were to occur, the reactor would scram automatically by other instruments, and the operator could manually initiate the Automatic Depressurization System and one of the low pressure injection systems. We therefore agree with the AEOD report that this matter is not an immediate safety concern.

Original signed by
D. G. Eisenhut

Darrell G. Eisenhut, Director
Division of Licensing

cc: E. Case
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D. Eisenhut
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