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Georgia Power
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W. A. Widner
Vice President and General Manager
Nuclear Generation

December 31, 1980

Director of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

NRC DOCKETS 50-321, 50-366
OPERATING LICENSES DPR-57, NPF-5
EDWIN I. HATCH NUCLEAR PLANT UNITS 1,2
SUBMITTAL OF INFORMATION REQUIRED BY NUREG-0737

Gentlemen:

Georgia Power Company hereby submits the information contained in Enclosures 1 through 18 in response to the reporting requirements of NUREG-0737 for January 1, 1981.

Should you have any questions or comments with regard to this submittal, please contact this office.

Yours very truly,

for W. A. Widner

WEB/eb

Enclosures

Sworn to and subscribed before me this 31st day of December, 1980.

Notary Public

Notary Public, Georgia, State at Large
My Commission Expires Sept. 20, 1983

xc: M. Manry
R. F. Rogers, III

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ENCLOSURE I

NUREG-0737 ITEM I.A.1.1

STA PROGRAM DESCRIPTION

Effective 1/1/81, the Shift Technical Advisor function will be performed by an engineer on shift qualified per the guidelines of NRC letter of 10/30/79. Each STA has a bachelor's degree or equivalent in a scientific or engineering discipline and has completed an STA training course from General Physics Corporation. That course was described in correspondence between the General Physics Corporation and the NRC (Gen. Physics Letter OPS-NRC 1047-80 dated January 16, 1980). The course was modified by the addition of two weeks of training and certain course material including human factors engineering based upon NRC comments.

The training program consisted of a total of 14 weeks of instruction. Of this, 6 weeks were classroom instruction conducted at Plant Hatch, and 8 weeks were combination of simulator and classroom instruction conducted at Tennessee Valley Authority's Browns Ferry Nuclear Plant BFNP simulator. Twelve of 14 weeks of instruction consisted of design series lectures, transient and accident lectures, and associated simulator operations and demonstrations. Successful completion of this portion of the program was based on passing written and oral examinations patterned after reactor operator and senior operator NRC examination. Passing criteria consisted of attaining an overall score of 70% or greater on the written examinations and a satisfactory oral and operating performance on the BFNP simulator. The remaining 2 weeks of instruction consisted of lectures on BWR chemistry, plant process computer operations and fundamentals of human factors. Successful completion of this portion of the program was based on achieving a score of 70% or greater on the weekly examinations covering the material.

Current plans for requalification training of the STAs are to include the STAs in the current RO and SRO requalification program. This consists of 96 hr/yr classroom training and 24 hr/yr simulator training.

The long-term STA program for Plant Hatch will be a continuation of the STA program in effect 1/1/81. This entails an engineer on shift qualified in general to the INPO document entitled "Nuclear Power Plant Shift Technical Advisor - Recommendations for Position Description", Revision - dated 4/30/80. Exceptions taken to the INPO document are as follows:

1. A comparison of each STA's qualification and educational background will be made to the INPO recommendations. Where deficiencies are found special programs will be inacted to upgrade the individual to minimum standards by 1/1/82.

2. The annual retraining program will be as described previously.

3. A waiver of any of the required education or training shall be granted only by the plant manager and will be evaluated on a case-by-case basis.

ENCLOSURE 2

NUREG-0737 ITEM I.C.I.

ACCIDENT AND TRANSIENT PROCEDURE REVIEW

In the Clarification of the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures," NUREG-0737 states:

> Owners' group or vendor submittals may be referenced as appropriate to support this reanalysis. If owners' group or vendor submittals have already been forwarded to the staff for review, a brief description of the submittals and justification of their adequacy to support guideline development is all that is required.

GEORGIA POWER COMPANY (G.P.C.) is an active participant in the BWR Owners' Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactors. Following are a brief description of the submittals to date, and a justification of their adequacy to support guideline development.

A. Description of submittals

(1) NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," August, 1979; including additional sections submitted in prepublication form since August, 1979.

(a) Section 3.1.1 (Small Break LOCA).

Description and analysis of small break loss-of-coolant events, considering a range of break sizes, location, and conditions, including equipment failures and operator errors; description and justification of analysis methods.

(b) Section 3.2.1 (Loss of Feedwater) - revised and resubmitted in prepublication form March 31, 1980.

Description and analysis of loss of feedwater events, including cases involving stuck-open relief valves, and including equipment failures and operator errors; description and justification of analysis methods.

(c) Section 3.2.2 (Other Operational Transients) - submitted in prepublication form March 31, 1980; revised and resubmitted in prepublication form August 22, 1980.

Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of analyses of Sections 3.1.1, 3.2.1, and 3.5.2.1 to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.

(d) Section 3.3 (BWR Natural and Forced Circulation)

Description of natural and forced circulation cooling; factors influencing natural circulation, including noncondensibles; reestablishment of forced circulation under transient and accident conditions.

(e) Section 3.5.2.1 (Analyses to Demonstrate Adequate Core Cooling) - submitted in prepublication form November 30, 1979; revised and resubmitted in prepublication form September 16, 1980.

Description and analysis of loss-of-coolant events, loss of feedwater events, and stuck-open relief valve events, including severe multiple equipment failures and operator errors which, if not mitigated, could result in conditions of inadequate core cooling.

(f) Section 3.5.2.3 (Diverse Methods of Detecting Adequate Core Cooling) - submitted in prepublication form December 28, 1979.

Description of indications available to the BWR operator for the detection of adequate core cooling (detailed instrument responses are described in Sections 3.1.1, 3.2.1, and 3.5.2.1).

(g) Section 3.5.2.4 (Justification of Analysis Methods) - submitted in prepublication form September 16, 1980.

Description and justification of analysis methods for extremely degraded cases treated in Section 3.5.2.1.

(2) BWR Emergency Procedure Guidelines (Revision 0) - submitted in prepublication form June 30, 1980.

Guidelines for BWR Emergency Procedures based on identification and response to plant symptoms; including a range of equipment failures and operator errors; including severe multiple equipment failures and operator errors which, if not mitigated, would result in conditions of inadequate core cooling; including conditions when core cooling status is uncertain or unknown.

B. Adequacy of Submittals.

The submittals described in paragraph A have been discussed and reviewed extensively among the BWR Owners' Group, the General Electric Company, and the NRC staff. The NRC staff has found (NUREG-0737 p. I.C.1-3) that "the analysis and guidelines submitted by the General Electric Company (GE) Owners' Group...comply with the requirements [of the NUREG-0737 clarification]." In Reference 1, the Director of the Division of Licensing states, "we find the Emergency Procedure Guidelines acceptable for trial implementation [on six plants with applications for operating licenses pending]."

G.P.C. believes that in view of these findings, no further detailed justification of the analyses or guidelines is necessary at this time.

Reference 1 further states, "[d]uring the course of implementation we may identify areas that require modification or further analysis and justification." The enclosure to Reference 1 identifies several such areas. G.P.C. will work with the BWR Owners' Group in responding to such requests.

By our commitment to work with the Owners' Group on such requests, on schedules mutually agreed to by the NRC and the Owners' Group, and by reference to the BWR Owners' Group analyses and guidelines already submitted, our response to the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" by January 1, 1981, is complete.

References

(1) Letter, D. G. Eisenhut (NRC) to S. T. Rogers (BWR Owners' Group), regarding Emergency Procedure Guidelines, October 21, 1980.

ENCLOSURE 3

NUREG-0737 ITEM II.B.2

PLANT SHIELDING

Georgia Power Company has completed an initial shielding analysis and has developed a design for shielding to address the results of that analysis in accordance with the requirements of NUREG-0737. However, the full impact of installation of the designed shielding on plant operation and safety may make such installation undesirable. This question will be discussed with the NRC staff prior to installation.

One deviation from the stated position in NUREG-0737 exists in the assumptions made for the shielding analysis. As noted in paragraph 3 of page 7 of Enclosure 6(b) of Georgia Power Company's letter of January 25, 1980, (attached to this enclosure) the source used in Containment Spray, Core Spray, HPCI liquid, RCIC liquid and, RHR-LPCI systems took credit for dilution of the reactor coolant system mass with the suppression pool mass. This dilution reflects the expected condition of reactor coolant and liquids recirculated by the above systems. This assumption affects the calculation of close rate in a linear fashion. If this assumption is not acceptable, please contact us at the earliest opportunity.

The release fractions for Cs and Rb were assumed to be 1% for the purposes of this shielding review. Further evaluations of the TMI radioactivity releases may conclude that higher release fractions are appropriate. However, the overall effects of higher release fractions on radiation levels or integrated exposures are not expected to be significant. Therefore, the Regulatory Guide 1.7 solids release fraction, 1% was used in this review. Similarly, no noble gases were included in the suppression pool liquid (Source C) because Regulatory Guide 1.7 has also set this precedent in modeling liquids in the pool. Furthermore, cursory analyses have indicated that the halogens dominate all shielding requirements and that contributions to the total dose rates from noble gases are negligible for the purposes of shielding design review.

3. Source Term Models

Section 2 above outlines the assumptions used for release fractions for the shielding design review. These release fractions are however, only the first step in modeling the source terms for the activity concentrations in the systems under review. The important modeling parameters, decay time and dilution volume, obviously also affect any shielding analysis. The following sections outline the rationale for the selection of values for these key parameters.

a. Decay Time

For the first stage of the shielding design review process, no decay time credit was used with the above releases. The primary reason for this was to develop a set of accident radiation zone maps normalized to no decay (refer to Appendix A) that could be used as a tool by the plant staff along with a set of decay curves (refer to Appendix B) to quantitatively assess the plant status quickly following any abnormal occurrence.

For analyses of personnel exposures in vital areas outside the control room, radioactive decay equivalent to the plant specific licensing basis LOCA delay (ten minutes) that is allowed for operator action was used as the <u>minimum</u> decay time.

b. Dilution Volume

The volume used for dilution is important, affecting the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions and decay times listed above to arrive at the final source terms for the shielding reviews:

Source A: Drywell and suppression pool free volumes.

Source B: Reactor coolant system normal liquid volume (based on reactor coolant density at the operating temperature and pressure).

Source C: The volume of the reactor coolant system plus the suppression pool volume.
Source D: Reactor coolant system normal vapor volume.

c. Sources Used in Piping and Equipment for Each System Under Review

In defining the limits of the connected piping subject to contamination listed below, normally shut valves were assumed to remain shut.

Containment spray system - Source C
Core spray system - Source C
High pressure collant injection system
  Liquid - Source C
  Steam - Source D
Reactor core isolation cooling system
  Liquid - Source C
  Steam - Source D
Residual heat removal system - Source C was used for the low pressure coolant injection mode
Sampling systems
  Containment air sample - Source A
  Reactor coolant sample - Source B
Reactor water cleanup system - Source B
Recombiner - Source A

B. The Shielding Design Review Methodology

1. Analytical Shielding Techniques

The previous sections outlined the rationale and assumptions for the selection of the systems that would undergo a shielding design review as well as the formulation of the sources for those systems. The next step in the review process was to use those sources along with standard point kernel shielding analytical techniques to estimate dose rates from those selected systems. For compartments containing the systems under review, estimates were made for a general area dose rate rather than to superimpose the maximum dose rate at contact with the surfaces of all individual components of that system in the compartment. For corridors outside compartments, reviews were done to check the dose rate transmitted into the corridor through the walls of adjacent compartments. Checks were also made for any piping or equipment that could directly contribute to corridor dose rates, i.e. piping that may be running directly in the corridor or equipment/piping in a compartment that could shine directly into corridors with no attenuation through compartment walls.

2. Accident Radiation Zone Maps

One of the two principal products of this review process is the

ENCLOSURE 4

NUREG-0737 Item II.E.4.2

CONTAINMENT ISOLATION DEPENDABILITY

Position 5:

The NRC, in Requirement II.E.4.2 of NUREG-0737 has indicated its position relative to containment isolation dependability. Part 5 of that position states the following:

> The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

The containment isolation analytical setpoint pressure for Mark I, II and III containments is approximately 2psig (drywell pressure). Under normal operating conditions, fluctuations in the atmospheric barometric pressure as well as heat inputs from such sources as pumps can result in containment pressure increases on the order of 1 psi. Consequently, the isolation setpoint of 2 psig provides 1 psi margin above the maximum expected operating pressure. The 1 psi margin to isolation has proved to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, it is such a low value (particularly in view of the small drywell volume of Mark I, II and III containments) that it provides a very sensitive and positive means of detecting and protecting against breaks and leaks in the reactor coolant system. No change of the setpoint is necessary for the Plant Hatch containments.

Position 6:

The subject valves meet the "October 23, 1979 Interim Position for Containment Purge and Vent Valve Operation Pending Resolution of Isolation Valve Operability".

ENCLOSURE 5

NUREG-0737 ITEM II.F.2

INADEQUATE CORE COOLING

Additional hardware to identify core cooling on BWR's has not been determined to be necessary at this time. Analysis and operator guidelines for the deletion and mitigation of inadequate core cooling are currently being developed in accordance with Requirement I.C.1 of NUREG 0737.

Material has already been submitted in response to this requirement as follows:

NEDO 24708 Section 3.5.2.1, Analyses to Demonstrate Adequate Core Cooling (Revised).

NEDO 24708 Section 3.5.2.3, Diverse Methods of Detection of Adequate Core Cooling.

NEDO 24708 Section 3.5.2.4 Justification of Analysis Methods.

These documents demonstrated the BWR's compliance with requirement II.F.2, noting that the primary method to assess adequate cooling in BWRs is the use of direct measurement of reactor water level. All events that threaten the ability to provide adequate core cooling have one common factor: the reactor water level decreases. The principal method of confirming adequate core cooling, the reactor pressure vessel water level instrumentation, has been shown through analysis and experience to be sufficient to assure detection of approach to inadequate core cooling. Secondary indications of low core water level are available including ECC system injection,and incore radiation flux instrumentation. These secondary indications are discussed along with water level instrumentations in NEDO 24708 section 3.5.2.3.

The development of system modifications "to provide more direct indication than that available with present instrumentation," is felt to be met since existing water level measurement already provides a direct means of detecting an approach to inadequate core cooling and confirming its mitigation as is necessary. Therefore no modifications are proposed.

The incorporation of core exit thermocouples into BWR design is being considered in the development of Regulatory Guide 1.97 Revision 2. Generic efforts in this regard are ongoing such as the NRC's request of General Electric Company contained in L.S. Rubenstein's letter dated August 22, 1980.

Georgia Power Company will pursue the question of in-core thermocouples upon completion of these generic studies and the issuance of Regulatory Guide 1.97 Revision 2.

ENCLOSURE 6

NUREG-0737 ITEM II.k.3.3

SRV CHALLENGES

The annual reporting of challenges to the Safety-relief valves described by NUREG-0660 and NUREG-0626 will be included in the Annual Operating Report normally submitted in March.

ENCLOSURE 7

NUREG-0737 ITEM II.k.3.13 A

Seperation of Initiation Levels of

the High Pressure Coolant Injection (HPCI) and Reactor

Core Isolation Cooling (RCIC) Systems

A report containing the analyses, conclusions and recommendations regarding seperation of the initiation levels of the HPCI and RCIC systems was transmitted to D.G. Eisenhut by R.H. Buchholz of General Electric Company on October 1, 1980. A copy of that letter is attached as part of this enclosure. Georgia Power Company plans no further action on this question based upon this report.

ENCLOSURE 8

NUREG-0737 ITEM II.k.3.13B

Reactor Core Isolation Cooling (RCIC) Automatic Reset

Attached is the Generic Analysis of RCIC Automatic Reset performed by the General Electric Company for BWR Owners Group. Georgia Power Company is reviewing the recommendations of the generic analysis, and is proceeding with the detailed design.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 ITEM II.K.3.13B

REACTOR CORE ISOLATION COOLING

(RCIC) SYSTEM AUTOMATIC RESET

TABLE OF CONTENTS

SUMMARY

NUREG-0737 requires evaluation of changes to the Reactor Core Isolation Cooling System to allow automatic restart following a trip of the system at high reactor vessel water level. The evaluation of this change showed that it would contribute to improved system reliability and that it could be accomplished without adverse effect on system function and plant safety. The recommended change would be to relocate the existing high level trip from the RCIC turbine trip valve to the steam supply valve. Once the level reaches a predetermined high level the steam supply valve would be closed. One additional relay in the logic circuitry would be required to accomplish the new function. The steam supply valve closure resets many of the functions initiated by the automatic start at low vessel level.

I. INTRODUCTION

The Reactor Core Isolation Cooling (RCIC) System is designed to assure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling. This prevents reactor fuel overheating during the following conditions:

a. Vessel isolation and hot standby condition.
b. Vessel isolation accompanied by loss of feedwater flow.
c. Complete plant shutdown under conditions of loss of normal feedwater system allowing reactor depressurization to a level where Residual Heat Removal (RHR) shutdown cooling may begin.

Following a reactor scram, steam generation will continue at a reduced rate due to the core fission product decay heat. If the main steam isolation valves remain open the turbine bypass system will divert the steam to the main condenser, and the feedwater system will supply the make-up water required to maintain reactor vessel inventory.

In the event the reactor vessel is isolated and the feedwater supply is unavailable, relief valves are provided to automatically (or remote manually) maintain vessel pressure within desirable limits. The water level in the reactor vessel will drop due to continued steam generation by decay heat. Upon reaching a predetermined low level, the RCIC System is initiated automatically. The turbine driven pump supplies demineralized make-up water from the condensate storage tank to the reactor vessel; an alternate source of water is available from the suppression pool. The turbine is driven with a portion of the decay heat steam from the reactor vessel, and exhausts to the suppression pool. When the water level in the reactor vessel rises the RCIC is automatically shutoff at a predetermined high level in order to prevent flooding of the steam lines.

NUREG-0737 recommends the following:

> Currently there is no automatic reset on the RCIC system after it trips on high reactor vessel water level. This requires manual reset by the operator. Depending upon the transient or accident, the operator may have to perform additional actions or be distracted to the extent that he may either forget or delay the reset of the RCIC system.
>
> To provide assurance that such an occurrence does not happen, the RCIC systems of all BWRs should be modified to incorporate an automatic reset on high reactor vessel water level. The RCIC system would then restart on loss of level. The operator would then only have to verify proper operation.

The purpose of this design assessment is to evaluate the above recommendation for the plants identified in Appendix A and provide a conceptual design change compatible with system requirements and generic to all BWR RCIC Systems*. The conceptual design does not include detailed implementation drawings or procedures.

*See Section VIII, Paragraph 1.

II. FUNCTIONAL REQUIREMENT

The change to the RCIC System should allow automatic cessation of flow to the reactor vessel at a predetermined high water level followed by automatic reset and/or realignment of the system to allow automatic initiation of flow again to the reactor vessel at a predetermined low water level.

III. EXISTING SYSTEM OPERATION

In the standby mode (Figure 1) the steam supply valve to the turbine is closed. When the vessel low water level signal (RCIC Autostart) is received, the RCIC System starts automatically without any action by the operator. The actions occurring upon automatic RCIC initiation are as follows:

a. The steam supply valve to the turbine opens to supply steam to the turbine. Steam line drain isolation valves then close, which isolates the RCIC steam supply from the main condenser.

b. Once the steam supply valve leaves the fully closed position, the ramp generator "ramp" function is initiated. This ramp generator controls the acceleration of the turbine via the turbine control valve.

c. The gland seal system automatically starts.

d. Condensate suction valve remains open or is opened to supply water to the RCIC pump.

e. Pump discharge valve opens to supply the water to the reactor vessel.

f. Cooling water supply valve opens, and coolant is supplied to the turbine lube oil cooler.

g. Test bypass valve, to the condensate storage tank closes, of open.

Shutdown of the RCIC System will be initiated automatically by any of the following:

a. Reactor high water level

b. RCIC pump low suction pressure

c. Turbine high exaust pressure

d. Turbine overspeed

e. Auto-isolation signal

f. Manual turbine trip pushbutton

Any of the above trip signals will release the spring loaded turbine trip valve. In order to reset the system it is necessary to first close the steam supply valve then drive the motor operator of the turbine trip valve in the close direction until the spring loaded closing latch mechanism is reset. Finally the turbine trip valve is driven to the full open position. Closure of the steam supply valve also resets the ramp generator, closes the vessel injection valve and minimum flow valve and opens the appropriate drain valves.

IV. OPTIONS FOR CHANGE

In order to incorporate automatic reset of the RCIC System subsequent to a high water level trip the following options are available.

1. Automate the reopening of the turbine trip valve following the high vessel level trip. This change requires first, the automatic closing of the steam supply valve then the relatching and opening of the turbine trip valve.

2. Automatic closure of the steam supply valve on high vessel level rather than the existing turbine trip valve. The turbine trip valve would stay open throughout the high level trip and reset operation*.

3. On high vessel water level trip reroute the RCIC pump flow from the vessel back to the condensate storage tank (if suction is from this source) leaving the turbine and pump in operation. If the suction supply is from the suppression pool the high vessel water level trip would close the steam supply valve as described in 2 above because extended minimum flow operation is not recommended.

*See Section VIII, Paragraph 1.

V. RECOMMENDATION

Option 1 involves automation of the opening of the turbine trip valve. For most BWR plants this valve is a spring loaded trip valve which requires driving the stem screw in the closed direction until the latch lever is engaged (loaded). The valve is then driven to the full open position. Before opening the turbine trip valve, the steam supply valve must be closed. The automatic resetting and opening of this mechanical trip valve requires rather extensive modifications to the logic circuitry with no real benefit.

Option 3 requires the logic circuitry to automatically divert injection flow from the vessel to the condensate storage tank without pump cavitation or turbine or turbine overspeed. This would be a complicated automation problem because of the required feedback to the turbine/pump flow controller. The logic circuitry would have to also decide which suction path is in use. Because of the complexity of this modification it is not recommended.

After considering the three options in the preceding section, it is recommended that option 2 be selected to accomplish the automatic reset following the high water level trip. The change allows for automatic closure of the steam supply valve on high vessel water level rather than close the turbine trip valve. Closure of the steam supply puts the system in a partial standby configuration because of the existing interlocks associated with closure of this valve. Very little modification to the logic circuitry is required to automate realigment of the system in preparation for low water level initiation

VI. IMPACT OF PROPOSED CHANGE

The proposed change will utilize the steam supply valve to shutoff the steam to the turbine on high vessel level rather than the turbine trip valve. The steam supply valve will now be used to both initiate system operation at low reactor vessel water level and terminate system operation at high water level.

The cessation of steam will be extended over a longer period of time due to the normal travel time of the steam supply valve. The spring loaded turbine trip valve closes essentially instantaneously. The steam supply valve closes in fifteen seconds or less. Conservatively assuming full rated flow throughout this extended shut off period and a maximum rated RCIC flow of 800 gpm, an additional 200 gallons will be added to the reactor vessel following the high vessel water level trip. This volume addition has an insignificant effect on high vessel level transients including those involving high volume systems (e.g., HPCI).

The duty on the steam supply valve is essentially the same; automatic closure will now occur rather than manual. The steam supply valve will be subjected to increased wear due to the wiredrawing experienced at closure. This effect should be minimal due to the low frequency of closures with steam flow through valve.

Adding an additional relay to the logic circuitry will increase the complexity of the system a minimal amount. From this standpoint the overall reliability of the system is minimally reduced, but this reduction is more than offset by the increased safety, reliability and availability created by the fact the steam supply valve is used to automatically reset the system.

A review of the Licensee Event Reports (LER) for 1977 through 1979 produced the following turbine trip and steam supply valve malfunctions.

	Did Not Open	Did Not Close
Turbine Trip Valve	4 events	2 events
Steam Supply Valve	4 events	0

From these few LER data points, it can be concluded that the reliability of the steam supply valve is comparable to the turbine trip valve. The existing control logic requires first the closure of the steam supply valve followed by the resetting and opening of the turbine trip valve. Since the proposed change eliminates the need to reset and open the turbine trip valve, the overall reliability is increased.

The definition of availability for this standby system is the probability that the system will be in operation condition when needed. Due to this new automatic reset feature the system availability is greatly enhanced.

The total impact on the BWR plant is improved safety. The operator is no longer required to manually reset the system following a high vessel water level trip. He will no longer be distracted by the necessary action and the possibility of inadvertent failure to reset is eliminated.

The proposed change does not reset all functions originally initiated by the low vessel level trip. Therefore the system is returned to a partial standby configuration. The following functions are not reset.

1. The gland seal compressor or vacuum pump (depending on plant) does not shut off.

2. The RCIC turbine lube oil cooling water supply valve does not close.

3. The low level seal-in for the manual isolation switch does not reset.

It is not necessary to automatically reset the above functions; manual reset by the operator is adequate. The gland seal system can continue to operate. The turbine lube oil cooling water supply valve is manually closed when the RCIC system is returned to the stand-by condition for all system trips. It is expected that if the valve were not manually closed it would have no adverse effect on system performance. Drainage from the condensate storage tank through the lube oil cooling line, to the Clean Radioactive Waste System is minimized by an orifice in the cooling water line. However, plant unique considerations may require that this valve be closed prior to system restart. In this case logic should be provided to automatically close the lube oil cooling water supply valve as part of the system logic reset required following the high vessel water level trip. The manual isolation switch feature is only used to prevent inadvertent pushbutton actuation with the system secured. No adverse impact on system operation will be experienced if manual reset is retained.

The proposed change utilizes the steam supply valve to terminate steam flow on high water level only. The other five RCIC trip parameters (i.e., low pump suction, turbine overspeed, etc.) will still close the turbine trip valve requiring manual reset of the system.

The pump discharge minimum flow valve is normally closed on any of the following signals: 1) RCIC discharge flow is high (i.e., greater than setpoint), 2) Turbine Trip and Throttle Valve is fully closed, or 3) Steam Supply Valve is fully closed. The latter two interlock signals assures that pump discharge minimum flow valve is closed when the RCIC system is in the stand-by condition. Each plant should verify these interlocks are part of their RCIC system logic.

VII. IMPLEMENTATION

The proposed change can be made as follows. (Refer to Figures 2 and 3 for the applicable Functional Control Diagram and Figures 4 and 5 for the applicable portion of the Elementary Diagram).

1. Remove the reactor high water level trip from the turbine trip valve circuitry by removing the level indicating switch contacts from the turbine trip auxiliary relay. Note that the interlock of the level switches with the steam supply valve full open limit switch is no longer necessary.

2. Add a new relay coil (KX) in series with the reactor high water level switches. (Recommend new relay be a GE Type HMA or HFA relay).

3. Add one normally open contact from the new high level relay (KX) across the closing leads of the steam supply valve, in parallel with the CLOSE switch contacts.

4. Add one contact of the new relay (KX) to the annunciator panel. Label the annunciator, "RCIC High Vessel Level."

*Not applicable to BWR/6.

VIII. GENERAL NOTES

1. Seven of the earlier BWR's* do not have an electrical trip solenoid on the turbine trip valve. The turbine trip valve associated with these turbine assemblies includes an oil dash pot system for engaging and releasing the trip mechanism. During standby condition the trip mechanism is not engaged. Once the turbine is started and oil pressure is developed, the dash pot system automatically engages the trip mechanism on the turbine trip valve. Once this mechanism is engaged, a trip may be accomplished by "dumping" the oil pressure in the dash pot. It must also be noted that any time the turbine is shut down by any means, the turbine trip valve will ultimately close on loss of oil pressure. In order for these seven plants to incorporate the recommended automatic reset they must replace the dash pot trip mechanism with an electrical trip solenoid on the turbine trip valve, similar to that mechanism used on later plants.

2. The additional annunciator is added because the existing turbine trip alarm is produced by a limit switch on the turbine trip valve. The recommended logic change will not produce an alarm unless specifically added. The noted wording of the annunciator window is only recommended.

3. The recommended implementation of this memorandum is generic to RCIC Systems as originally designed by General Electric Company. Additional functions added by the AE or plant owner may effect the actual change. All plant owners should review their existing system for any conflicts. One specific example would be the starting of the room cooler controlled by the opening of the steam supply valve. For high water level closure of this valve it may not be desirable to secure the room cooler.

4. The recommended implementation is based on relay type logic. For solid state plants, relays are replaced with solid state devices.

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*Monticello, Vermont Yankee, Fitzpatrick, Pilgrim, Quad Cities 1/2, and Cooper.

IX. CONCLUSION

The automatic reset of the RCIC system following a high water level trip will improve the overall safety of the BWR. The recommended use of the steam supply valve to secure steam flow will result in an easily implemented change, incorporating the recommendations of NUREG-0737, Item II.K.3.13b.

APPENDIX A

PARTICIPATING UTILITIES

NUREG-0737, II.K.3.13b

This report applies to the following plants, whose owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Niagara Mohawk Power	Nine Mile Point 2
Nebraska Public Power District	Cooper
Northern States Power	Monticello
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	FitzPatrick
Tennessee Valley Authority	Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 & 2
Detroit Edison	Enrico Fermi 2
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

ENCLOSURE 9

NUREG-0737 Item II.k.3.15

Isolation of HPCI and RCIC Modification

Attached to this enclosure is a copy of the evaluation of proposed modification to the break detection logic to prevent spurious isolation of HPCI and RCIC systems performed by General Electric Company on a generic basis for the BWR Owners Group. Georgia Power Company is proceeding with development of detailed design and implementation. Completion of installation of time delays of approximately 3 seconds to HPCI and RCIC steam line isolation circuits is scheduled.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 ITEM II.K.3.15

MODIFY BREAK DETECTION LOGIC TO PREVENT

SPURIOUS ISOLATION OF HPCI AND RCIC SYSTEMS

TABLE OF CONTENTS

NUREG-0737 REQUIREMENT II.K.3.15

FIGURES

NUREG-0737 REQUIREMENT II.K.3.15

SUMMARY

The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems have flow meters in the turbine steam supply lines. The primary purpose of these flow meters is to isolate the system in the event a steam line ruptures. The devices continually monitor steam flow rate and will initiate closure of the HPCI/RCIC steam line when the measured flow rate in that line exceeds a trip set point typically 300% of rated flow. However, HPCI/RCIC steam line flow rates can also exceed nominal conditions during the start sequence for these systems. Despite the fact that these are momentary flow peaks, the current isolation logic does not discriminate between these conditions and the sustained high steam flow rates associated with a steam line break. Consequently a spurious system isolation can sometimes occur during the start sequence. In NUREG-0737 Item II.K.3.15 the NRC suggested that the HPCI/RCIC pipe break detection circuitry be modified to eliminate the possibility of spurious system isolations while still preserving the break detection/isolation capability of these devices.

GE and the BWR Owners' Group have reviewed this issue and agree that the current control logic could contribute to an unnecessary degradation of HPCI/RCIC system availability. Consequently, individual utilities may choose to modify their HPCI/RCIC systems. Plant to plant variations exist in HPCI/RCIC design details and these differences require that each utility develop a plant unique implementation plan for its particular BWR facility. GE and the BWR Owners' Group recognize the need for a consistent overall technical approach to this change and will continue to provide a technical focal point for this program. This memorandum describes a conceptual HPCI/RCIC change based on adding a time delay to the break detection circuitry. This memorandum may be used by individual utilities as they develop definitions of the detail design change for their particular reactors.

1. INTRODUCTION

This memorandum has been prepared in response to NUREG-0737 Item II.K.3.15. In this requirement, the NRC identified a concern with the break detection circuitry associated with the turbine steam supply lines of the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. The NRC concern centers on the inability of the break detection equipment to discriminate between the sustained high flow conditions associated with a steam line rupture and the short duration high flow peaks that can occur during system start transients. As a result, these flow devices can produce a spurious system isolation during a start sequence which can cause an unnecessary degradation of system availability.

GE and the BWR Owners' Group have reviewed this matter for the plants identified in Appendix A and concur that the NRC suggestion may lead to some enhancement of HPCI/RCIC availability. Consequently, individual utilities may choose to modify their HPCI/RCIC break detection and isolation equipment. However plant to plant variations exist in HPCI/RCIC design details and these differences require that each utility develop a plant unique implementation plan for its particular BWR facility. GE and the BWR Owners' recognize the need for a consistent overall technical approach to this change and will continue to provide a technical focal point for this program. This memorandum describes a conceptual HPCI/RCIC change based on adding a time delay to the break detection circuitry.

Section 2 is a more detailed description of the potential problem associated with the current steam supply line flow sensors. This description is included because it will assist in understanding the proposed solution. (It is assumed that the users of this memorandum are familiar with the HPCI/RCIC systems and no system descriptive material has been included).

GE has reviewed several potential solutions to this HPCI/RCIC design issue and has concluded that the best approach is a modification based on adding a time delay to the isolation circuitry. This time delay will prevent short term flow peaks from initiating a system isolation but will not interfere with the break detection and isolation function of this equipment.

Section 3 describes the various design solutions that were considered and discusses the technical bases for concluding that a time delay scheme is the best approach. Section 4 defines the design requirements for this approach and presents a conceptual design change. The latter is intended to represent a starting point for the definition of individual plant unique design modifications.

2. DESIGN ISSUE

Figure 1 shows a typical RCIC or HPCI steam supply line. Two normally open* isolation valves are provided in each steam line. One isolation valve is located inside the drywell and is controlled by an AC motor. The other valve is located outside the drywell and is controlled by either an AC or DC motor. These valves automatically close on receipt of an isolation signal.

Typically, elbow flow** meter systems are located in both the RCIC and HPCI steam supply lines. An elbow flow meter device senses the differential pressure between the inside and outside radii of the bend and (using suitable calibration information) converts the measured pressure differences into a flow rate. For the HPCI and RCIC systems, these flow instruments are supplemented by trip units and other control and instrumentation equipment that will initiate and complete closure of a steam supply line isolation valve when the flow in that line exceeds 300% of rated flow. Since a guillotine rupture of a steam line will produce steam flow rates up to ten times rated flow, the 300% setpoint will clearly produce system isolation in the event of a pipe break. The technical issue identified by the NRC in this NUREG-0737 requirement is that the 300% setpoint may be exceeded during the short duration flow peaks that can occur during the HPCI/RCIC start sequences. Figure 2 is a schematic diagram of this sequence. A high initial HPCI/RCIC flow rate will occur (in part) because both of these systems have demanding performance requirements governing their time-to-rated flow characteristics. These starting requirements translate into high turbine angular acceleration rate and thus high initial steam flow conditions.

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* Some reactors have normally closed outboard isolation valves with a normally open small diameter bypass line. The latter permits sufficient steam flow to keep the steam supply lines heated.

** Some reactors have alternate flow measuring devices such as Venturi's.

Clearly plant safety considerations do not require system isolation because of momentary peak steam flow rates during startup and any such isolation that occurs is an unnecessary degradation of HPCI/RCIC availability. There are several design changes capable of eliminating this concern and these changes are discussed in the next section.

3. POTENTIAL SOLUTIONS

Several HPCI/RCIC design changes are capable of eliminating the unnecessary system isolations that can occur as a result of short term flow peaks in the steam supply lines. This section briefly describes these various design solutions and identifies their advantages and disadvantages. It is concluded that the best technical approach to this issue is to add a time delay in the flow sensing isolation system logic. This time delay will prevent unnecessary isolations but still preserve the ability of the system to sense and isolate a steam supply line break. Table 1 summarizes the alternatives that have been examined.

GE and the BWR Owners' Group believe the addition of a time delay to the HPCI/RCIC break detection circuitry is the best solution because it is simple, inexpensive and directly addresse the problem. It can be incorporated into operating reactors with minimum difficulties and with minimum impact on the systems involved. A time delay solution fully preserves the break detection/isolation capabilities of the existing system and can be designed to have no impact on the currently documented accident analysis of HPCI/RCIC steam supply line breaks (see Section 4.4). Furthermore, it is believed that components meeting the requirements governing this emergency system equipment are available and can be procured within a reasonable time period. Addition of snubber devices to the elbow tap instrument lines (Option 2, Table 1) has some of the same advantages as the time delay approach. However, the snubber solution does have disadvantages in that it does not represent as positive a solution as the time delay and requires plant-specific selection of the required damping characteristics. Furthermore, the snubber could be subject to performance degradation due to crud buildup. Also, they would have to be located in the drywell and this could lead to maintenance difficulties.

Some operating BWRs have already eliminated spurious HPCI and/or RCIC isolations by adopting the type of time delay scheme discussed in this memorandum. Operating experience with these modifications provides confidence that addition of a time delay is a suitable generic BWR design modification.

Superficially it might appear that an increase in the isolation setpoint from the current nominal value of 300%* to a higher value might represent the simplest solution to this issue. However, such a change would require extensive plant unique accident analyses involving not only the HPCI/RCIC systems but also the leak detection systems provided in the HPCI/RCIC equipment rooms. Consequently, it has been concluded that raising the isolation setpoint is not an acceptable approach.

* Actual nominal trip setp..nts are typically 280%. This difference reflects instrument error and drift allowances.

4. CHANGE IMPLEMENTATION

Addition of an isolation system time delay is recommended as a solution to the spurious HPCI/RCIC isolation issue. This section discusses the factors which each utility must consider when preparing detailed implementation plans for its facility. Typical RCIC/HPCI Elementary Diagrams and Functional Control Diagrams are included as guidance.

4.1 Design Requirements

The break detection circuit modification should meet the following major design requirements.

a) Fully eliminate inadvertent system isolations resulting from flow peaks which occur during the system start sequence.

b) Have little or no adverse impact on plant safety.

c) Be retrofitable to operating BWRs without requiring major modifications of the HPCI/RCIC system hardware or control and instrumentation components.

d) Have an adjustable time delay setpoint to permit plant-specific adjustments.

e) Meet all the regulatory requirements and codes and standards which apply to the reactor under consideration.

4.2 Design Change

The above design requirements can be met by replacing the existing zero delay isolation relay in each break detection circuit with a Class IE time delay relay with an adjustable time delay between 0 and 15 seconds. (A setpoint of at least 3 seconds but less than the 13 seconds analytical limit will be required. See Sections 4.3, 4.4.) This will involve no design changes in the differential pressure measuring devices. Both the RCIC/HPCI systems have two break detection circuits and in both cases each circuit controls one of the two isolation valves described in Section 2. Both circuits in both systems must be modified. Figure 3 and 4 show typical examples of those parts of RCIC and HPCI Elementary Diagrams which will be changed when the time delay relay replaces the existing isolation relay. Figure 5 shows a typical Functional Control Diagram for a HPCI/RCIC isolation valve.

For BWR projects with solid state control circuitry, some signal transmitting devices are capable of damping the process signal (see Item 1a of Table 1). With suitable engineering analysis of the transient HPCI/RCIC steam flow, this type of transmitter could be used to eliminate spurious HPCI/RCIC isolations. Due to the disadvantages as described in Item 1a of Table 1, we do not recommend this type of modification. It is believed that solid state circuit modification giving a discrete time delay is the preferred solution for solid state plants.

Figure 6 summarizes in schematic form the sequence of events that will occur during the start transient after a time delay has been added. The timer will be started when the flow rate sensed by elbow flow meters exceeds the trip setpoint. The latter is somewhat less than the analytical limit of 300% of rated flow; a value of 280% is typical. This difference provides margin for instrument errors and instrument drift and ensures that actual plant performance would be within the scope of the assumptions used for the plant accident analyses. At the end of the timer period, system isolation will only occur if the flow meters are still reading at or above the trip setpoint. As demonstrated in Figure 6, the high steam flow due to a pipe break will persist longer than 13 seconds and thus will ensure that isolation of a pipe break has occurred.

4.3 Time Delay Setpoint

Plant specific information on the duration of the steam supply line flow peaks as measured by the elbow tap meters is usually not available. On the basis of past experience, G.E. believes that the approximate times shown on Figure 2 are representative and that a 3 second time delay would be adequate to ensure the short term flow peaks will not produce an unnecessary isolation. However, because HPCI/RCIC characteristics will vary somewhat from plant to plant and furthermore may not be particularly repeatable, it is recommended that an adjustable time delay be used with an adjustment range of 0 to 15 seconds. An initial setpoint of 3 seconds is recommended and HPCI/ RCIC testing after the modification can be used to guide any setpoint adjustments that might be necessary. The setpoint should have 3 second minimum and 13 second maximum analytical limits.

Accuracy of the time delay period is not critical and it is suggested that the delay relays be purchased with accuracies that are consistent with accepted nuclear industry design practices. If this is considered too imprecise and specification of a numerical accuracy requirement becomes necessary, it is suggested that a value of ± 1/2 second would be adequate.

4.4 Safety Evaluation

The design objective of the HPCI/RCIC isolation systems is to limit the radiological consequences of a steam supply line rupture. The radiological consequences of such an accident are determined by the total quantity of radioactivity discharged to the environment which in turn is determined by the total amount of reactor fluid that is released at full steam flow condition as a result of the pipe break. The total fluid mass release is determined by a combination of the size of the broken steam line and the time required isolation valves in that line to close and terminate reactor blowdown. Addition of a time delay will not result in any change in the total reactor fluid mass release when the design basis conditions are considered. Figure 7 summarizes the factors which contribute to this conclusion. The key point is the 13 second valve closure delay period currently assumed during the design basis evaluation of a steam supply line break. This extended delay results from the assumption that the DC isolation valve fails and that no offsite AC power is immediately available to the AC valve. The diesel-generator start and emergency bus loading sequence is assumed to require 13 seconds and will preclude any movement of the AC valve prior to this time. Because of this power supply delay assumption, an additional timer in the DC powered control logic will not extend the reactor blowdown period and consequently will not influence the total fluid mass and radioactivity released from the reactor. It should be understood that this conclusion relates to the design basis conditions. In the event of an actual steam line break, it is unlikely that these conservative design basis assumptions will be representative of actual conditions. For example, it is probable that both AC and DC power will be continuously available to the isolation valves and both valves will start to close immediately. Under these circumstances, the proposed additional time delay will extend the blowdown period and lead to a small increase of fluid release. However, the key point is that with a 3 to 13 second time delay, these releases will still be considerably less than the design basis conditions and within existing safety analyses.

It is concluded that addition of a time delay to the HPCI/RCIC steam supply line isolation system does not have any adverse safety implications. Furthermore, this change does not invalidiate the design basis safety evaluation of this equipment and any plant that incorporates the timer should not have to repeat any safety analyses. The technical specification will be required to be changed to include time delay surveillance.

5. CONCLUSIONS

Adding a time delay of approximately 3 seconds to the HPCI/RCIC steam line isolation systems should eliminate any spurious isolations that may occur as a result of flow peaks occurring during a normal system start transient. This design change can be simply applied to operating BWRs and does not involve any major hardware modifications. The change is responsive to the NRC requirement of NUREG-0737 Item II.K.3.15 and does not impact the accident performance of this equipment; no revision of existing safety analyses is required. Sufficient information is included in this memorandum to permit individual BWR utilities to initiate detailed plant unique change activities.

TABLE 1

NUREG-0737 REQUIREMENT II.K.3.15: RCIC/HPCI BREAK DETECTION

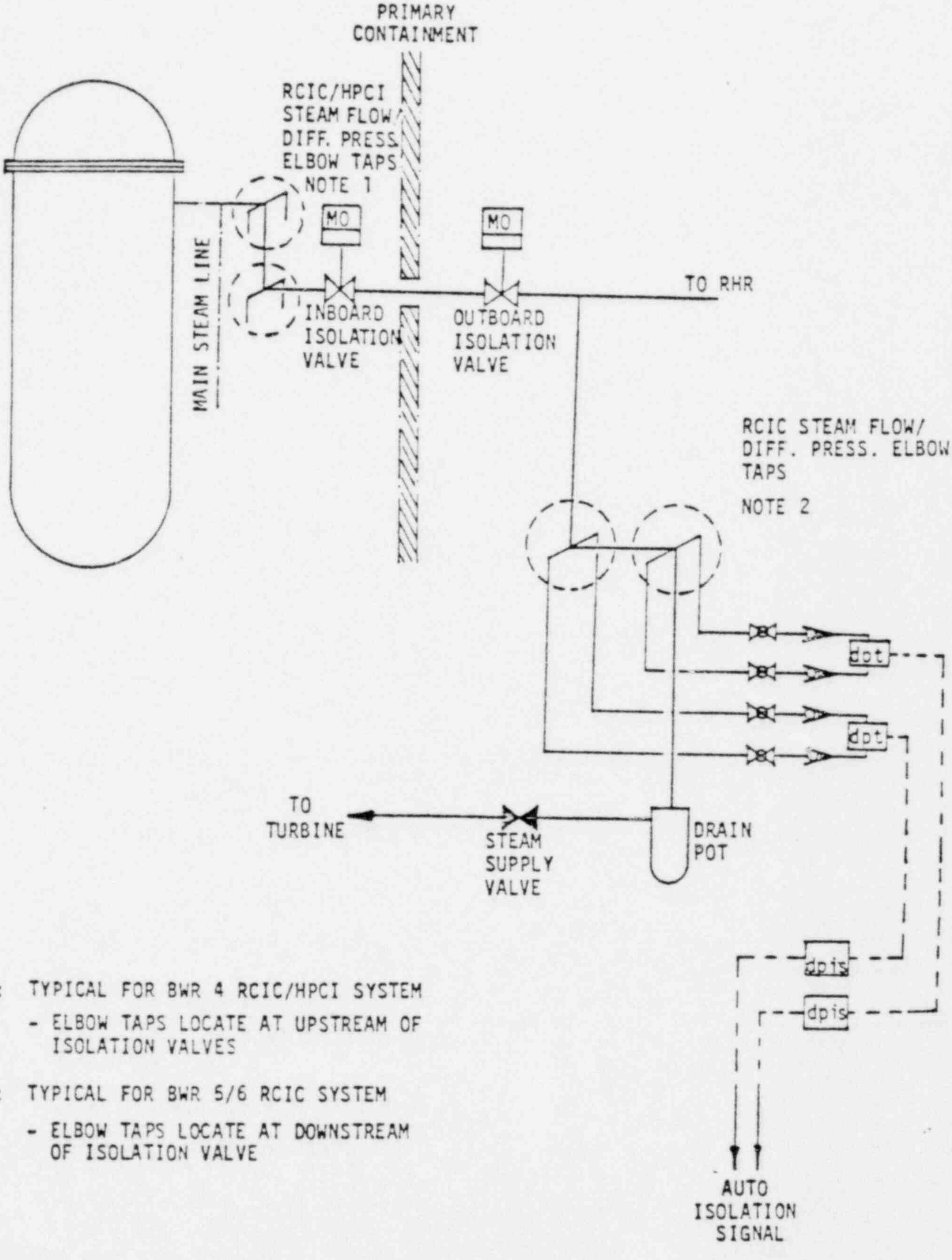
DESIGN MODIFICATIONS FOR ELIMINATING SPURIOUS SYSTEM ISOLATIONS

Design Modification	Advantage	Disadvantage	Comments
1. Add a time delay to the flow measurement system and select a delay period sufficiently long so that system starting flow peaks will not trip the isolation system. Preserve break detection/isolation capability	- Simple and inexpensive change - Convenient to perform surveillance and operability tests - Control room environmental conditions (as opposed to more rigorous conditions for other locations) - Successful field experience - Minor design perturbation. No major hardware changes - Current SAR analyses valid - Current break detection and isolation functions preserved		May permit significant reduction of trip set point for these instruments and thus eliminate one source of plant LER
1a. For BWRs with solid state control circuit add a dynamic time delay to the electronics of the signal transmitters to dampen out short duration flow peaks	Advantages similar to those identified above for the time delay solutions	- On site selection of damping characteristics required - Affects of damping on steam break and starting transient are difficult to analyze - Delay time greatly affected by the magnitude of the flow signal	Not a recommended solution. See Section 4.2 also
2. Add a snubber device to the flow measurement instrument lines to dampen out short duration flow peaks	Advantages similar to those identified above for the time delay solutions	Not a positive solution. In-situ selection of damping characteristics required. Location in drywell may add maintenance requirements - Subject to crud build up	Not a recommended solution

TABLE 1 (CONT'D)

Design Modification	Advantage	Disadvantage	Comments
3. Raise the nominal trip setpoint (NTSP) from the current value of approximately 300% to a higher value that will avoid spurious trips	No hardware Changes	- Significant analytical effort to demonstrate that a revised setpoint will meet plant safety requirements. (Reactor fluid and radioactivity releases to the environment) - Significant safety analysis report and technical specification perturbations	
4. Elbow flow meter devices are not particularily accurate and replacement with a more accurate device (eg: venturies) would permit reduction in the instrument drift specifications. This could possibly lead to a reduction in spurious isolations because for the same analytical trip setpoint a higher nominal trip setpoint could be used		- Field changes to HPCI/RCIC piping - Not a clear cut solution in that existing peak short term flow rates are not known and may not be repeatable	Not an attractive solution
5. Modify the RCIC/HPCI systems to eliminate the short term flow peaks occuring during the system start transients. These modifications could involve small diameter bypasses around the steam supply valves or other modifications of the steam supply and turbine control equipment	Potential best long-term solution	- Major hardware changes are required - Testing would be required. (developmental and calibration) - May not be able to eliminate flow peaks and still meet system functional requirements, especially the time-to-rated flow requirement	This type of RCIC/HPCI change would involve extended schedule

FIGURE 1



NOTE 1: TYPICAL FOR BWR 4 RCIC/HPCI SYSTEM

- ELBOW TAPS LOCATE AT UPSTREAM OF ISOLATION VALVES

NOTE 2: TYPICAL FOR BWR 5/6 RCIC SYSTEM

- ELBOW TAPS LOCATE AT DOWNSTREAM OF ISOLATION VALVE

SCHEMATIC DIAGRAM SHOWING POTENTIAL
SPURIOUS ISOLATION DURING HPCI/RCIC START SEQUENCE

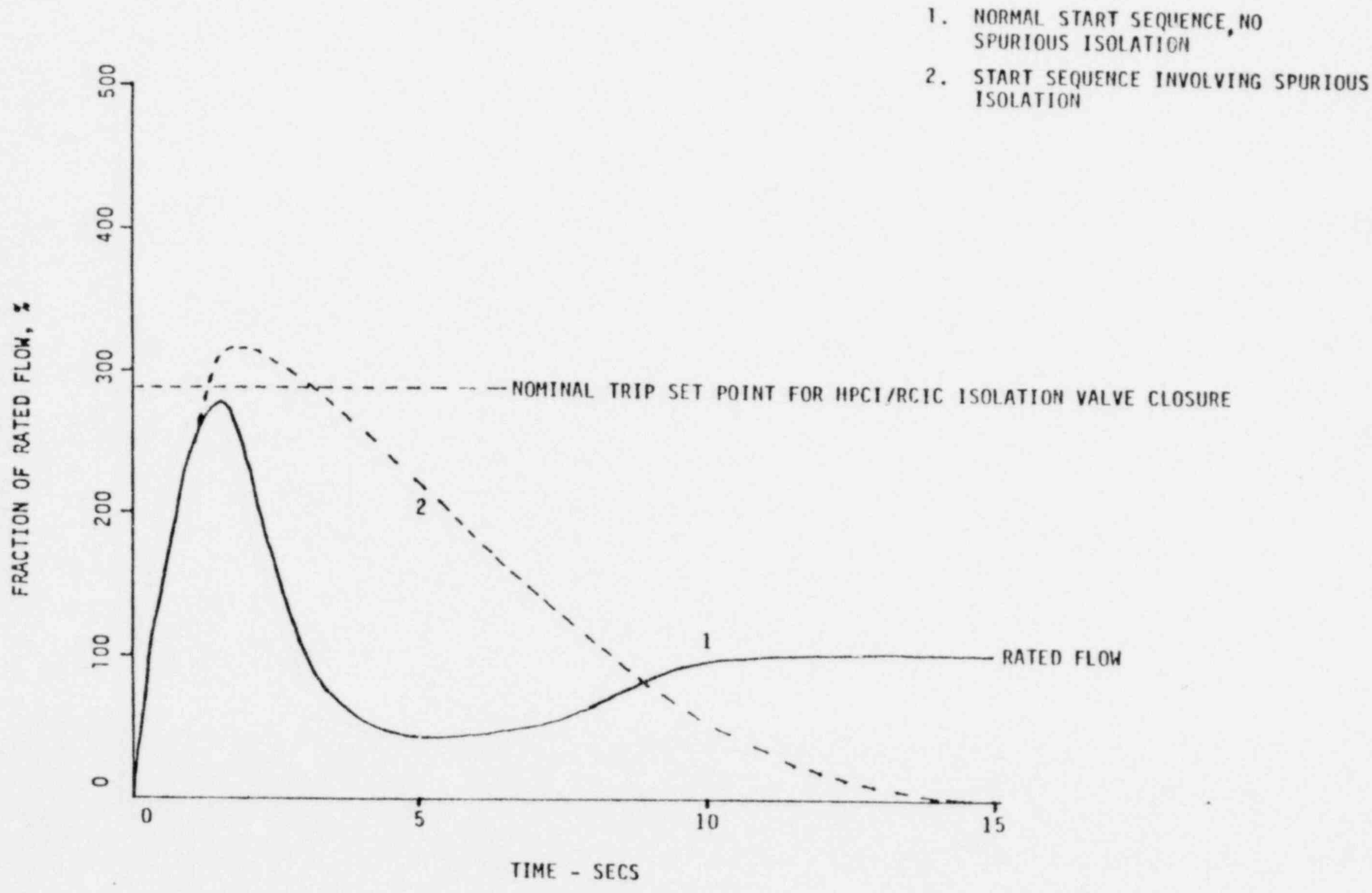


FIGURE 2

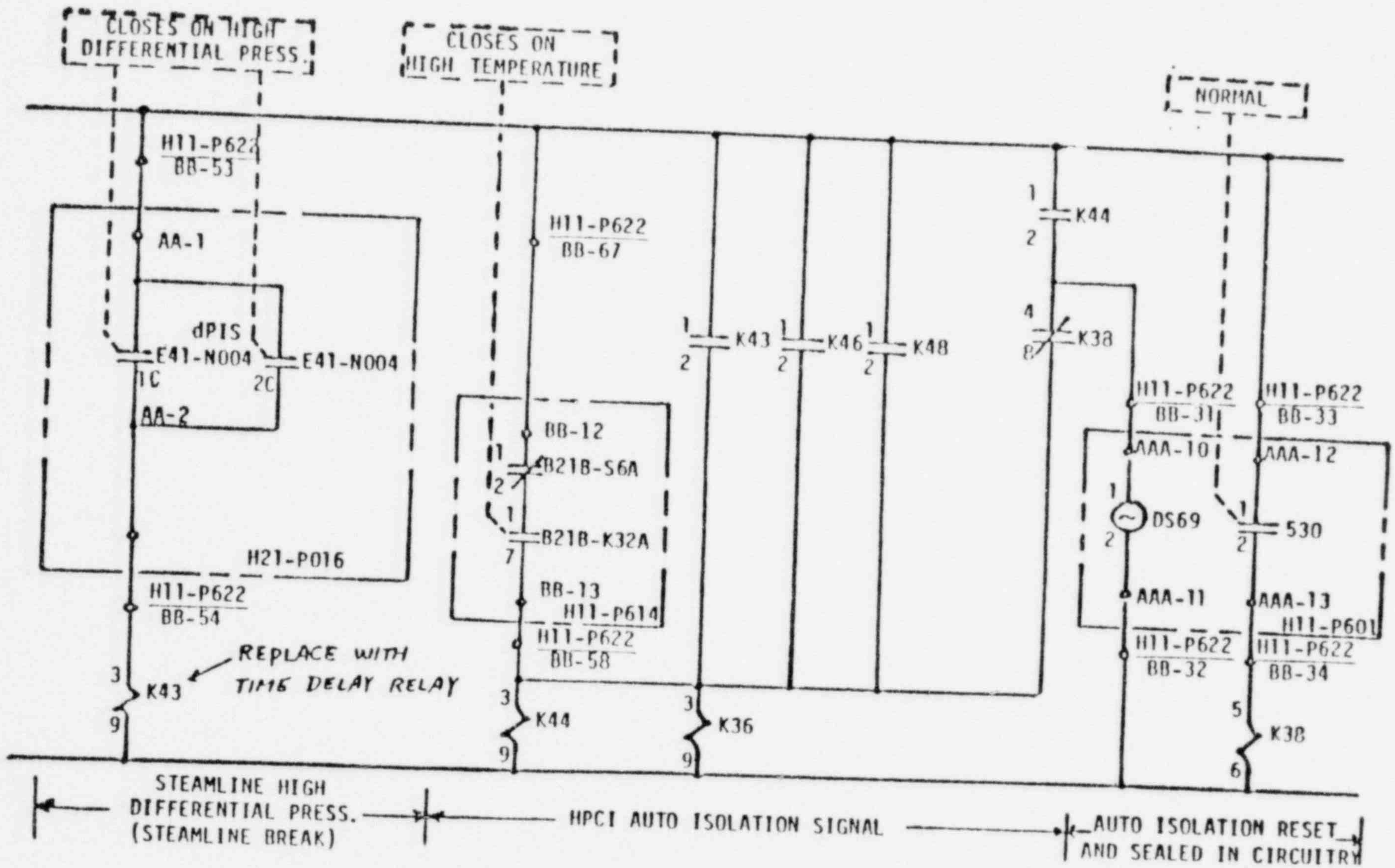


FIGURE 3: A TYPICAL HPCI STEAMLINE BREAK DETECTION LOGIC DIAGRAM

Proposed to replace existing relay, as shown above, with a comparable qualified Class IE, 0-15 second Time Delay Relay

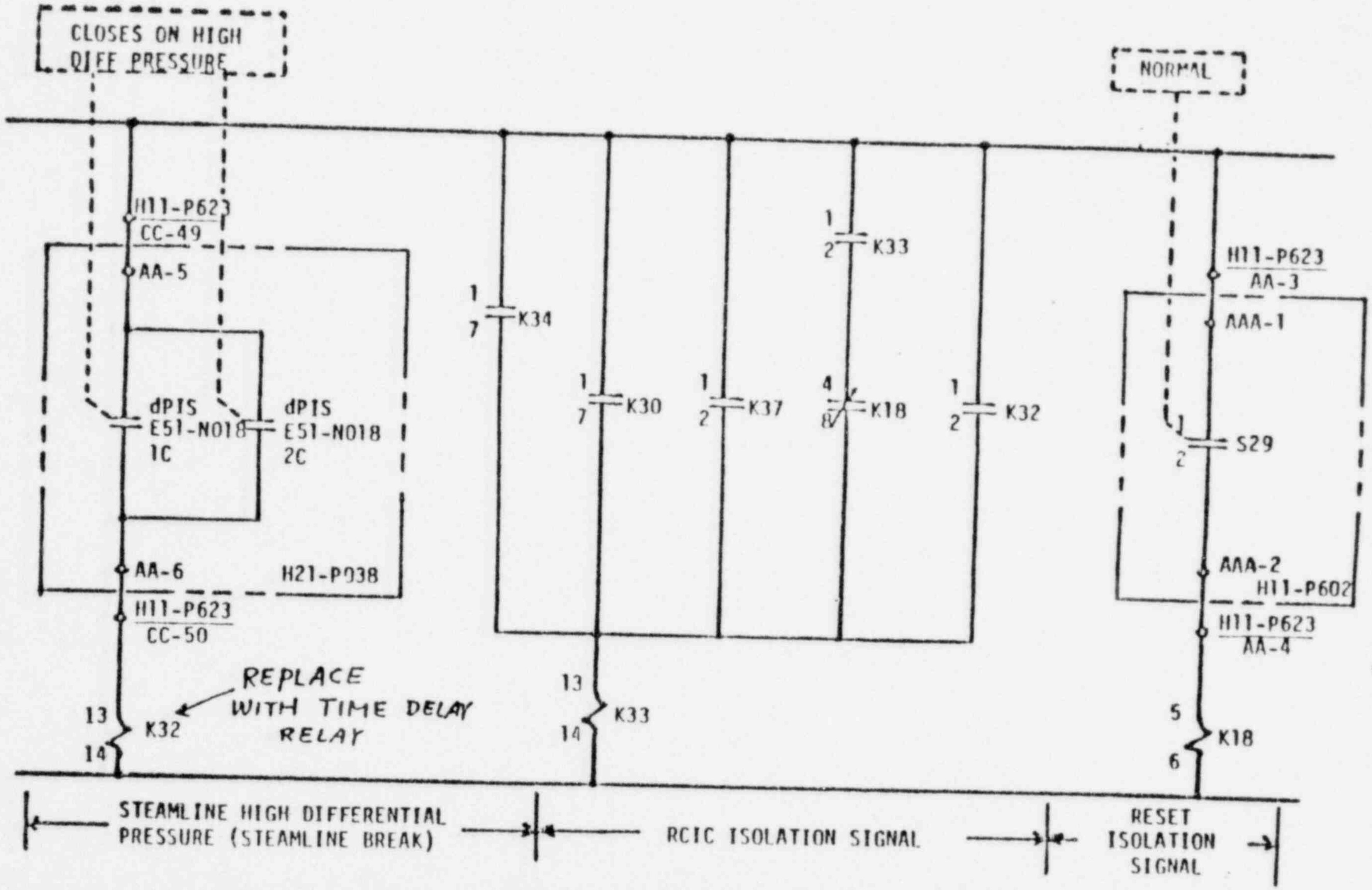


FIGURE 4: A TYPICAL RCIC STEAMLINE BREAK DETECTION LOGIC DIAGRAM

Proposed to replace existing relay (as shown above) with a qualified Class IE, 0-15 second Time Delay Relay

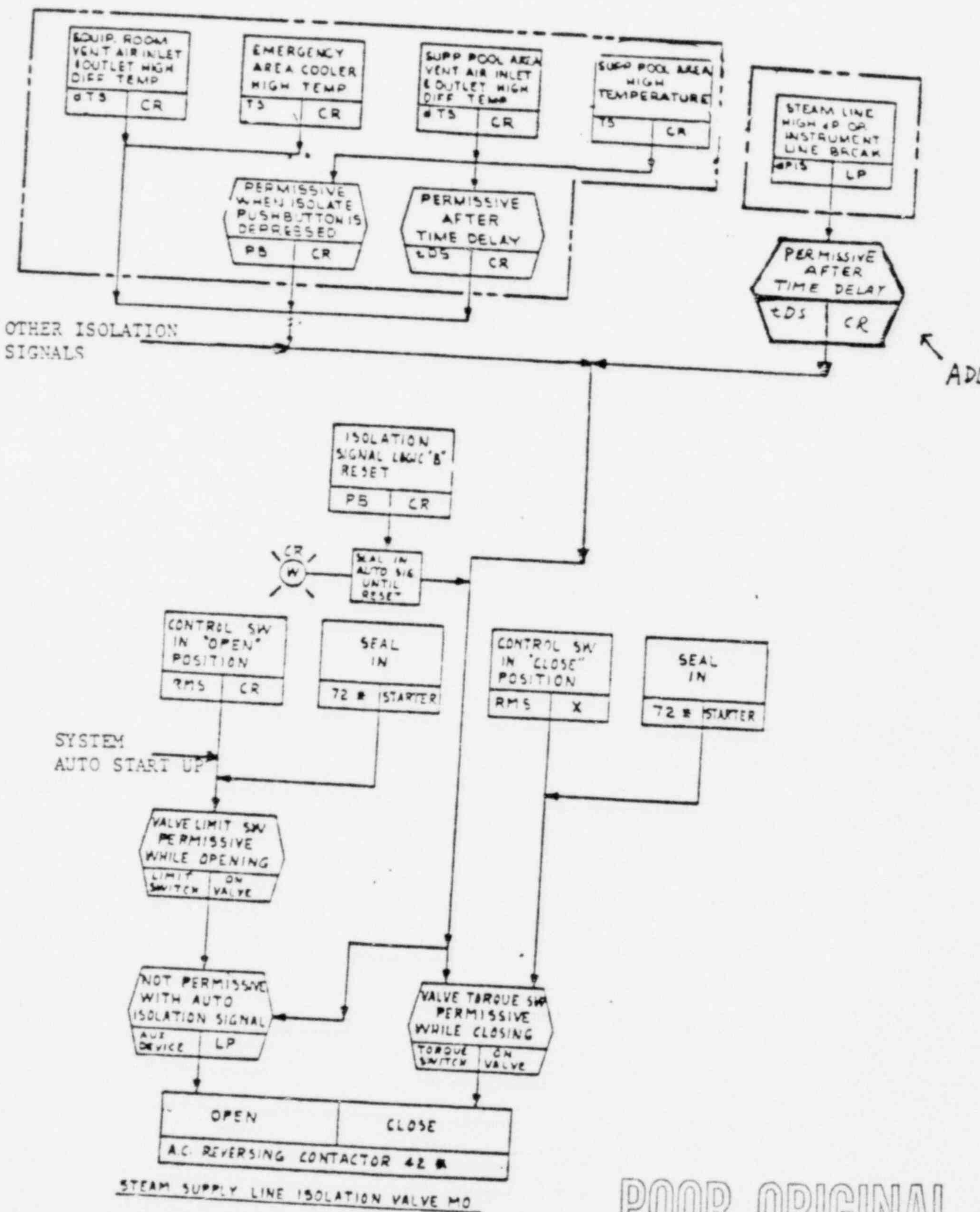


FIGURE 5: RCIC/HPCI BREAK DETECTION LOGIC FCD

FIGURE 6

SCHEMATIC DIAGRAM OF TIME DELAY ACTION TO PRECLUDE SPURIOUS HPCI/RCIC ISOLATION DURING SYSTEM START SEQUENCE

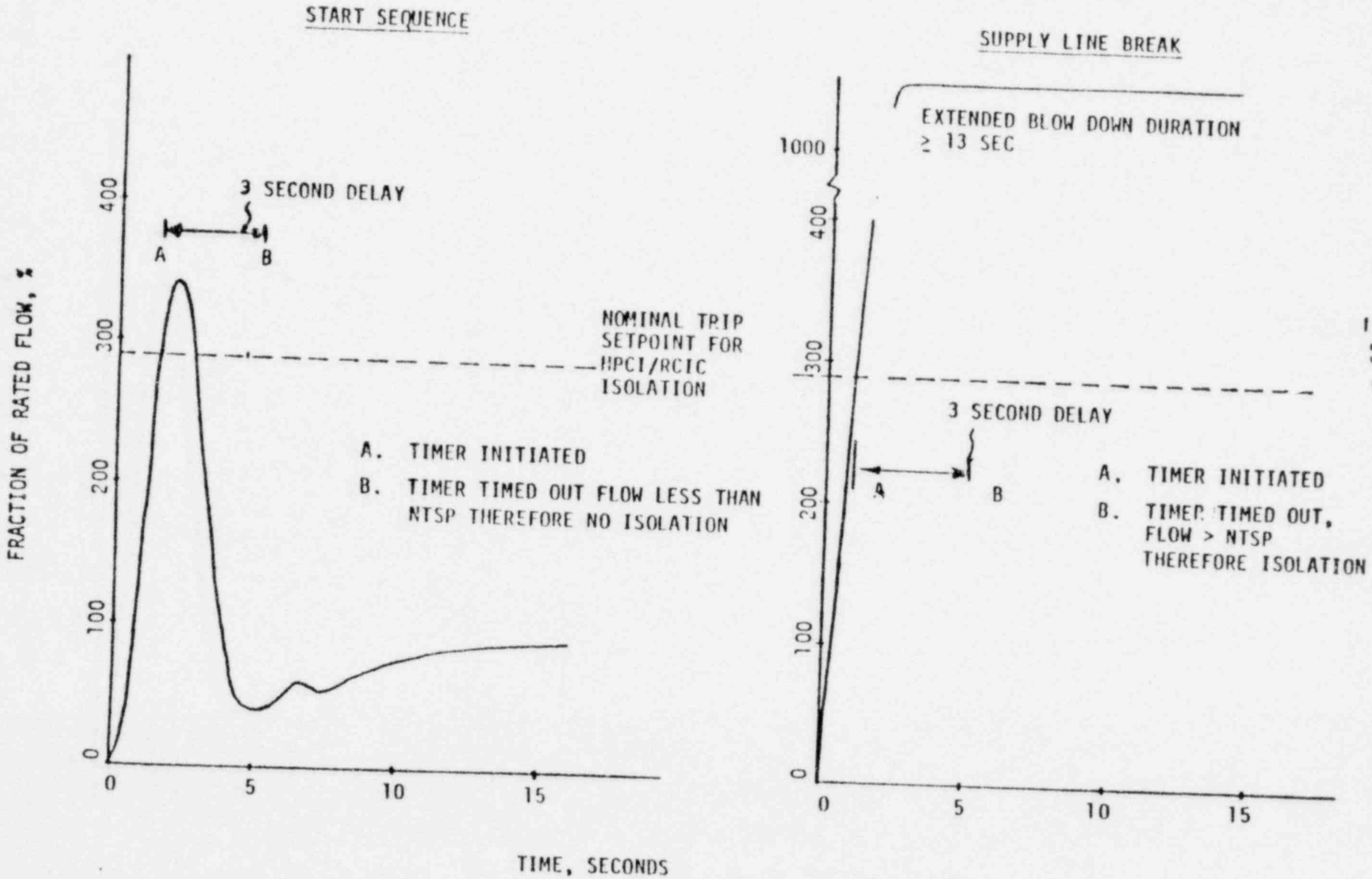


FIGURE 7

SEQUENCE OF EVENTS

Design Basis Conditions:

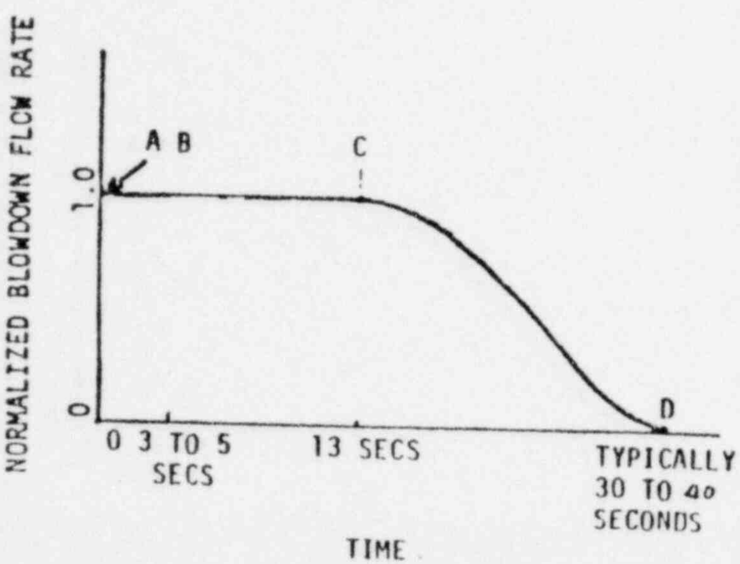
i) Instantaneous Guillotine pipe rupture

ii) D.C. valve fails

iii) No offsite power, 13 second delay for diesel-generator start and emergency bus loading

Time Into Event	Existing Design With No Isolation Time Delay	Proposed Design With Isolation Time Delay
A. ~ 0 sec	- High ΔP isolation signal generated - Diesel generator (D-G) signaled to start - Isolation valve receives signal to close, but has no power	- High ΔP isolation signal generated - Diesel generator signaled to start - 3 sec timer actuated
B. 3 sec		- Isolation time delay timed out (3 second) - Isolation valves receive signal to close but has no power
C. 13 sec	- Power available from D.G., valves start to close	- Power available from D.G., valves start to close
D. 30-40 sec	- Valve fully closed*	- Valve fully closed*

*In both cases, valves close at same time, conclusion: addition of timer does not increase total mass of steam release to the environment.



APPENDIX A

Participating Utilities

NUREG-0737 II.K.3.15

This report applies to the following plants, whose Owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 1-3
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Northern States Power	Monticello
Pacific Gas & Electric	Humboldt Bay 3
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Detroit Edison	Enrico Fermi 2
Long Island Lighting	Shoreham
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

ENCLOSURE 10

NUREG-0737 ITEM II k.3.17

ECC SYSTEM OUTAGES

Attached is a final draft of a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation of Unit I and for perior sinc fuel loading for Unit 2. Completion of the review and the submittal of the report is expected by January 12, 1981. Additionally a review of this report is being conducted to determine if there are possible modifications which would improve the availability of ECCS components.

The recommendations which result from that review, if any, will be submitted for NRC information as soon as they are available.

GP-R-33009

OPERABILITY REVIEW

OF THE

EMERGENCY CORE COOLING SYSTEMS

AT

PLANT HATCH - UNITS 1 & 2

for

Georgia Power Company

230 Peachtree Street

P. O. Box 4545

Atlanta, Georgia 30302

GP-R-33009

December 22, 1980

PRELIMINARY

Prepared by

General Physics Corporation

Columbia, Maryland

(Under Purchase Order No. E53974)

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PRELIMINARY

SECTION 1. INTRODUCTION

1.1 Purpose and Scope

This document was prepared in response to TMI Action Plan Requirement II.K.3.17, "Report on Outages of ECC Systems". An extensive review of operating and maintenance records was conducted to obtain details on dates, lengths and causes of outages for Emergency Core Cooling Systems (ECCS) at Plant Hatch, Units 1 and 2. Results for operability of the ECCS are presented for the most recent five year period of operation for Unit 1, and for the period since fuel loading for Unit 2.

Cumulative outage times are given for each major subsystem of the ECCS. These outage times are considered quite conservative since they include events which resulted in the apparent loss of function of an ECCS subsystem component (even though partial or complete function should have actually been available) as well as events which clearly made an ECCS subsystem/component unavailable. As an additional conservatism, for the purposes of this study, the definition of those subsystems/components which belong to the ECCS was expanded beyond that given in the Hatch Final Safety Analysis Report (FSAR). Specifically, the containment cooling mode of the Residual Heat Removal (RHR) System, the RHR Service Water System, the Plant Service Water (PSW) System, and the Standby Diesel Generators have been included in the study results.

The overall purpose of this report is to provide the historical Hatch ECCS operability data requested by the NRC, to support the determination of whether a need exists for cumulative outage requirements in the Technical Specifications.

1.2 Background

The NRC Action Plan (Reference (1)) developed as a result of the Three Mile Island Unit 2 accident, included various measures to be taken to improve the capability of plants to mitigate the consequences of loss-of-coolant accidents and loss-of-feedwater events (Task II.K). Item II.K.3.17 of the Action Plan requires a report on ECCS outages for boiling water reactor plants. Clarifications given in References (2) and (3) define the NRC position, which is repeated below:

> "*Several components of the ECC systems are permitted by Technical Specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (e.g., controller failure, spurious isolation).*
>
> *The present Technical Specifications (T/S) contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present T/S requirements but have a high unavailability because of frequent outages within the allowable T/S.*
>
> *The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the Technical Specifications.*"

A study was therefore undertaken at Hatch to quantify the historical ECCS outage times. This was performed by conducting a thorough review of relevant plant records. Results are provided for the period from December 1, 1975 to December 1, 1980 for Unit 1, and from July 1, 1978 to December 1, 1980 for Unit 2.

PRELIMINARY

SECTION 2. GENERAL APPROACH

2.1 Description of the ECCS and Related Systems/Components

The Hatch Emergency Core Cooling Systems consists of the following four separate subsystems (References (6) and (7)):

- High Pressure Coolant Injection (HPCI) System
- Automatic Depressurization System (ADS)
- Core Spray (CS) System
- Low Pressure Coolant Injection (LPCI) Mode of the RHR System

The ECCS are designed to limit fuel clad temperature over the complete spectrum of possible break sizes in the nuclear system process barrier, up to an including the double-ended break of the largest line connected to the reactor vessel. Tables 1 and 2 give summaries of the important characteristics of the ECCS subsystems for each unit, and indicate how backups are available for each subsystem.

PRELIMINARY

The following additional systems/components are included in this ECCS operability review because of the nature in which they support the ECCS in carrying out their design functions under various assumed accident conditions:

- Containment Cooling Mode of the RHR System
- RHR Service Water System
- Plant Service Water System (PSW)
- Standby Diesel Generators

The Equipment area coolers for the HPCI and RHR pumps are included with the HPCI and RHR Systems (for the purposes of this study) since failure of these coolers would affect operation of the ECCS.

2.2 Technical Specification Limiting Conditions of Operation

The Technical Specifications (References (4) and (5) define the

TABLE 1: ECCS DATA FOR HATCH UNIT #1

SYSTEM	NO. INSTALLED	INDIVIDUAL CAPACITY	DESIGN RATING*	PRESSURE RANGE	A. C. POWER REQUIREMENTS	BACKUP SYSTEMS
HPCI	1	100%	4250 gpm @ 1120 - 150 psid	1120 psig to 150 psig	None	ADS, LPCI, & CS
ADS	7	20%	800,000 $\frac{lb}{hr}$ @ 1125 psid	1125 psig to 50 psig	None	Remote/ Manual relief valves
CS	2	100%	4625 gpm @ 113 psid	265 psig to 0 psig	Normal Aux. or Standby Diesel	LPCI
LPCI	4	33 1/3%	7700 gpm @ 20 psid	290 psig to 0 psig	Normal Aux. or Standby Diesel	CS

PRELIMINARY

*psid - Pounds per square inch differential between reactor vessel and primary containment.

requirements for availability of the ECCS and the limitations imposed on operation when portions of the ECCS are unavailable. Tables 3 and 4 summarize the requirements of the Hatch Units 1 and 2 Technical Specifications which are relevant to this ECCS operability review. Tables 3 and 4 also show the current ECCS outage time limitations for the Hatch plants.

Tables 3 and 4 can be used to establish the type of events which constitute an ECCS outage for the purposes of this study. An ECCS outage is considered to be any event which results in a Limiting Condition of Operation (LCO) as defined by the Technical Specifications. It is not necessary to include periods of inoperability during which operability is not needed. For example, if during Run Mode the HPCI pump is declared inoperable (resulting in an LCO), and then 3 days later the plant is shutdown for 3 months and the LCO is not cleared until just prior to startup, the outage period for the HPCI pump is taken as 3 days (not 3 months plus 3 days) since the HPCI System is not required when the reactor is shut down.

PRELIMINARY

2.3 Records Search

To establish historical ECCS outages for Hatch, the following types of plant records were reviewed:

- Records for Limiting Conditions of Operation (LCO's)
  - derived from HNP-901, Revisions 2 through 4
  - covers period from 9/79 to present
- Records for Cumulative Downtime
  - derived from HNP-901, Revision 0 and Revision 1
  - covers period from 5/76 to 9/79
- Records for Equipment Operating Times (precedec HNP-901)
  - derived from Standing Order 75-2
  - covers period from 1/75 to 7/75

TABLE 3: SUMMARY OF TECHNICAL SPECIFICATION REQUIREMENTS FOR THE

HATCH UNIT 1 ECCS AND RELATED SYSTEMS/COMPONENTS

ECCS SYSTEM	PLANT OPERATING MODE REQUIREMENT*	T/S SECTION	INOPERABLE SYSTEM/COMPONENT	REQUIRED OPERABLE SYSTEM/COMPONENTS	OUTAGE TIME LIMITATION
Core Spray	Prior to Startup from Cold Shutdown	3.5.A.1	None	All	-
	or Irradiated Fuel in Vessel and reactor pressure is greater than atmospheric	3.5.A.2	One CS	One CS RHR/LPCI Diesels	7 days
RHR (LPCI and Containment Cooling Mode)	Prior to Startup from Cold Shutdown	3.5.B.1.a	None	All	-
	or Irradiated Fuel in vessel and reactor pressure (P) greater than atmospheric	3.5.B.1.b	None	1 RHR W/2 pumps or 2 RHR W/1 pump ea.	-
	Power Operation	3.5.B.1.d	None	LCPI E11-F010 closed & locked annunciator op.	
	Prior to Startup	3.5.B.1.e	None	Both recirc pump disch. valves	
		3.5.B.2.a	1 LPCI pump	Remaining LPCI pumps Both LPCI sub-system flow paths CS Diesels	7 d

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TABLE 3 (Continued)

ECCS SYSTEM	PLANT OPERATING MODE REQUIREMENT*	T/S SECTION	INOPERABLE SYSTEM/COMPONENT	REQUIRED OPERABLE SYSTEM/COMPONENTS	OUTAGE TIME LIMITATION
		3.5.B.2.b	1 LPCI subsystem (both LPCI pumps or active valves in that system)	Remaining LPCI sub-system CS Diesels	7 d
	Irradiated Fuel in vessel and pressurized or prior to startup	3.5.C.1 a&b	None	RHR Service Water	-
	Irradiated Fuel in vessel & de-pressurized	3.5.C.1.c	None	1 RHR service loop	-
	Power Operations	3.5.C.2	1 RHR pump	All others in both subsystems	30 d
		3.5.C.3	2 RHR pumps	All redundant active components in both subsystems	7 d
HPCI	Prior to Cold Startup or	3.5.D.1	None	All	
	Irradiated Fuel in vessel and P >113 psig	3.5.D.2	HPCI	ADS CS RHR (LPCI) RCIC	14 d

PRELIMINARY

TABLE 3 (Continued)

ECCS SYSTEM	PLANT OPERATING MODE REQUIREMENT*	T/S SECTION	INOPERABLE SYSTEM/COMPONENT	REQUIRED OPERABLE SYSTEM/COMPONENTS	OUTAGE TIME LIMITATION
RCIC	Prior to Cold Start or	3.5.E.1	None	All	-
	Irradiated Fuel in vessel and P >113 psig	3.5.E.2	RCIC	HPCI	7 d
ADS	Prior to Cold Start or	3.5.F.1	1 of 7 vlaves	6 of 7 valves	-
	Irradiated Fuel in vessel and P >113 psig	3.5.F.2	2 of 7 valves	HPCI	30 d
Min core/ containment cooling		3.5.G	1 standby diesel	RHR (LPCI) containment cooling	7 d
RHR (shutdown cooling)	Irradiated Fuel and Cold Shutdown (and no work which could drain vessel)	3.5.G	CS LPCI Containment cooling	Shutdown cooling of RHR	- -

PRELIMINARY

TABLE 4: SUMMARY OF TECHNICAL SPECIFICATION REQUIREMENTS

FOR THE

HATCH UNIT 2 ECCS AND RELATED SYSTEMS/COMPONENTS

ECCS SYSTEM	PLANT OPERATING MODE REQUIREMENT*	T/S SECTION	INOPERABLE SYSTEM/COMPONENT	REQUIRED OPERABLE SYSTEM/COMPONENTS	OUTAGE TIME LIMITATION
HPCI	Conditions 1, 2, 3 & Steam Dome Pressure(P) >150 psig	3.5.1	HPCI	RCIC ADS CS LPCI	14 d
ADS	Cond. 1, 2, 3 & P > 150 psig	3.5.2	None	7 ADS valves	
			1 ADS valve	6 ADS valves HCPI CS LPCI	14 d
CS	Cond. 1, 2, 3	3.5.3.1	1 CS Loop	Both LPCI	7 d
	Cond. 4, 5		1 CS Loop	1 LPCI within 4 hrs. O/W suspend OPS. that may drain vessel	4 hrs.
	Cond. 1		2 CS Loop	1 LPCI & other LPCI within 4 hrs. (see above)	4 hrs.

PRELIMINARY

*For definition of Conditions, see explanation at end of table.

TABLE 4: Continued

ECCS SYSTEM	PLANT OPERATING MODE REQUIREMENT *	T/S SECTION	INOPERABLE SYSTEM/COMPONENT	REQUIRED OPERABLE SYSTEM/COMPONENTS	OUTAGE TIME LIMITATION
LPCI	Cond. 1, 2, 3	3.5.3.2	1 LPCI Loop or 1 LPCI Pump	Both CS	7 d
	Cond. 4, 5		1 or 2 LPCI	See Action Req'd by 3.5.3.1	

PRELIMINARY

*Conditions:
1 - Run Mode
2 - Startup and Standby
3 - Shutdown and Hot Standby
4 - Shutdown and Cold Shutdown
5 - Refueling

- Daily Operating Reports
  - derived from HNP-400
  - covers entire period
- Deviation Reports (DR's)
- Maintenance Requests (MR's)
- Design Change Requests (DCR's)
- Licensee Event Reports (LER's)
- Shift Foreman and Operator Log Books

PRELIMINARY

The general procedure used was to first extract basic ECCS outage data from the plant records for Limiting Conditions of Operation (recorded per Plant Procedure HNP-901 and Standing Order 75-2). Where additional information was needed, the other documentation sources were reviewed. It should be noted that LCO records contained the most complete data, and the outage results compiled for the time period when the procedure for compiling these records was in effect contains the highest degree of accuracy. For the earlier time periods, outage details were more difficult to obtain and in many cases it was necessary to provide estimates.

The plant status during an ECCS maintenance or test evolution was a major factor considered in compiling the study results. Many maintenance and testing tasks are performed on ECCS components when the plant is in a shutdown mode. For many of the tasks performed in shutdown mode, the affected ECCS subsystem is not required to be operational, and the maintenance or testing task should therefore not be accounted for as an ECCS outage. The major plant shutdown periods for which this logic was applied (in compiling the study results) are as follows:

UNIT 1	UNIT 2
11/16/75 - 12/23/75	8/20/78 - 10/11/78
3/27/76 - 4/21/76	12/25/78 - 2/3/79
3/12/77 - 5/17/77	2/15/79 - 5/28/79
3/3/78 - 4/14/78	3/1/80 - 4/22/80
5/8/78 - 6/15/78	11/1/80 - present
4/22/79 - 8/22/79	
12/15/79 - 1/4/80	
1/24/80 - 2/1/80	
5/24/80 - 6/11/80	

PRELIMINARY

SECTION 3. RESULTS

Attachments A and B provide detailed summaries of ECCS outages for Hatch Units 1 and 2, respectively. The results given in these attachments tend to overstate the actual ECCS outages, since events are included which appear to compromise system capability when in fact partial or full function of the system would be expected. Those items which are questionable in this regard are assumed to be true ECCS outages, lending to the overall conservatism of the study results.

ECCS outages are listed chronologically in Attachments A and B according to the following scheme:

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Table A - High Pressure Coolant Injection System

Table B - Automatic Depressurization System

Table C - Core Spray System

Table D - Low Pressure Coolant Injection and Containment Cooling Modes of RHR System

Table E - RHR Service Water System

Table F - Plant Service Water System

Table G - Standby Diesel Generators

Tables 5 and 7 summarize the data given in Attachment A for Unit 1, and Tables 6 and 8 summarize the data given in Attachment B for Unit 2. Tables 5 and 6 give summaries of all ECCS outage events sorted by system and by year. Tables 5 and 6 do not account for overlapping events in a given system, and therefore reflect an overstatement of the cumulative ECCS outage times. Tables 7 and 8 give the cumulative ECCS outage times for Hatch Units 1 and 2, respectively.

Table 5 shows that the duration of an ECCS outage event for Unit 1 has averaged 1.5 days over the past five years of operation, with the yearly average ranging from 0.9 days to 2.6 days per outage event. Table 6 shows that the duration of an outage event for Unit 2 has averaged 1.9 days over

Table 5 : Summary of ECCS Outage Events for Hatch Unit 1 by System and Year

System	Year					Total	Average
	1976 ✓	1977	1978	1979	1980		
High Pressure Coolant Injection (HPCI System)	0.5d* (2)†	10.2d (5)	4.6d (8)	11.0d (7)	6.1d (7)	32.4 (29)	1.1 days/ event
Automatic Depressurization System (ADS)	0	0	0.05d (1)	0	0	0.05 (1)	0.05 days/ event
Core Spray (CS) System	0.5d (1)	1.7d (3)	18.0d (5)	13.4d (3)	0.96d (4)	34.6 (16)	2.2 days/ event
RHR (LPCI and Containment Cooling), and Service Water	2.8d (7)	4.6d (10)	5.3 (6)	25.8 (14)	31.6 (28)	70.1 (65)	1.1 days/ event
Plant Service Water	31.4d (13)	6.9 (12)	28.6 (12)	53.4 (18)	76.4 (19)	196.7 (74)	2.7 days/ event
Standby Diesel Generators	7.2d (17)	23.8d (24)	19.9 (27)	44.7d (16)	17.8 (16)	113.4 (100)	1.1 days/ event
Total	42.4 (40)	47.2 (54)	76.5 (59)	148.3 (75)	132.9 (71)	447.3 (299)	1.5 days/ event
Average	1.1 days/ event	0.9 days/ event	1.3 days/ event	2.6 days/ event	1.8 days/ event		

PRELIMINARY

✓ 1976 data include December, 1975
* Total time in effect (days)
†( ) Indicates total number of outage events

Table 6 : Summary of ECCS Outage Events for Hatch Unit 2 by System and Year

System	Year				
	1978	1979	1980	Total	Average
High Pressure Coolant Injection (HPCI System)	1.8 d* (3) †	18.4d (17)	28.2d (19)	48.4 (39)	1.2 days/ event
Automatic Depressurization System (ADS)	0	0	0	0	0 days/ event
Core Spray (CS) System	0	2.9d (3)	9.5d (7)	12.4d (10)	1.2 days/ event
RHR (LPCI and Containment Cooling), and Service Water	62.1 (10)	3.9d (7)	3.2d (11)	69.2 (28)	2.5 days/ event
Plant Service Water	0.3 (1)	56.5d (9)	31.3d (20)	88.1d (30)	2.9 days/ event
Standby Diesel Generators	16.5d (4)	9.5d (9)	11.3 (11)	37.3 (24)	1.5 days/ event
Total	80.7 (18)	91.2 (45)	83.5d (68)	255.4 (131)	1.9 days/ event
Average	4.5 days/ event	2.0 days/ event	1.2 days/ event		

PRELIMINARY

* Total time in effect (days)

†( ) Indicates total number of outage events

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Table 7 : Cumulative System Outage Times for Hatch Unit 1 ECCS

System	Year					Total	Average
	1976	1977	1978	1979	1980		
High Pressure Coolant Injection (HPCI System)	0.5d	10.2d	4.6d	11.0d	6.1d	32.4d	6.5 days/yr.
Automatic Depressurization System (ADS)	0	0	.05d	0	0	0.05d	0.01 days/yr.
Core Spray (CS) System	0.5d	1.7d	18.0d	13.4d	0.96d	49.9d	10.0 days/yr.
RHR (LPCI and Containment Cooling), and Service Water	2.8d	4.6d	5.3d	25.2d	30.7d	68.6	13.7 days/yr.
Plant Service Water	29.4d	6.9d	28.6	42.4d	74.3d	188.6	37.7 days/yr.
Standby Diesel Generators	7.2d	21.3d	19.8d	30.4d	17.4d	96.1	19,2 days/yr.
Total	40.4d	44.7d	76.3d	30.4d	126.5d		
Average	6.7 days/sys	7.5 days/sys	12.7 days/sys	21,6 days/sys	21.1 days/sys	69.5 days/sys	13,9 days/sys-yr.

Table 8 : Cumulative System Outage Times for Hatch Unit 2 ECCS

System	Year 1978	Year 1979	Year 1980	Total	Average
High Pressure Coolant Injection (HPCI System)	1.8d	18.4d	28.2	48.4d	16.1 days/yr.
Automatic Depressurization System (ADS)	0	0	0	0	0 day/yr.
Core Spray (CS) System	0	2.9d	9.5d	12.4d	4.1 day/yr.
RHR (LPCI and Containment Cooling), and Service Water	78.3d	3.9d	3.2d	85.4d	28.5 day/yr.
Plant Service Water	0.3d	56.5d	29.8d	86.6	28.9 day/yr
Standby Diesel Generators	16.5d	9.5d	11.3d	37.3d	12.4 day/yr
Total	96.9d	91.2d	82.0d	45.0 / sys	15.0 days / sys - yr.
Average	16.2 days / sys	15.2 day / sys	13.7 day / sys		

* Total time in effect (days)

( ) Indicates total number of outage events

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the period since fuel loading, with the yearly average ranging from 1.2 days to 4.5 days per outage event.

Tables 7 and 8 show that the cumulative outage times average 14 days per system-year for Unit 1, and 15 days per system-year for Unit 2.

PRELIMINARY

SECTION 4. REFERENCES

1. NUREG-0660" NRC Action Plan Developed as a Result of the TMI-2 Accident", May, 1980.

2. 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.

3. Letter to all Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, "Preliminary Clarification of TMI Action Plan Requirements", D.G. Eisenhut, September 5, 1980.

4. Operating License DPR-57, Technical Specifications and Bases for Hatch Unit 1, Georgia Power Company, Docket No. 50-231.

5. Operating License NPF-5, Technical Specifications and Bases for Hatch Unit 2, Georgia Power Company, Docket No. 50-366.

6. Edwin I. Hatch Unit 1 Final Safety Analysis Report, Ammendment 78, October 1, 1980.

7. Edwin I. Hatch Unit 2 Final Safety Analysis Report, Ammendment 17, October 1, 1980.

PRELIMINARY

ATTACHMENT A

PRELIMINARY

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DETAILED SUMMARY OF ECCS OUTAGES

FOR HATCH UNIT 1

(12/1/75 - 12/1/80)

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
5-4-76	1340	5-4-76	2135	Flow Switch E41-N006		6	55
8-20-76	1335	8-20-76	1820	To repair E41-F028		5	15
1-30-77	0910	1-30-77	1340	Checking D.C. Mov's for Surveillance test		3	30
3-8-77	0615	3-8-77	1655	Perform overspeed trip		10	40
8-14-77	0745	8-14-77	1735	Steam Leaks Fixed		9	55
8-28-77	2107	9-4-77	1415	P41-C001D Rebuild pump, "D" PSW pump seal leaking	6	17	8
9-28-77	0630	9-30-77	1300	HPCI INOP	1	10	
1-4-78	0650	1-4-78	1430	HPCI, to repair control linkage		12	40
1-6-78	0640	1-6-78	1200	HPCI For Maintenance to readjust oil relief valve		5	20
2-24-78	2300	2-25-78	1215	E41-C002 Performed overspeed test		5	30
5-7-78	1150	5-7-78	1415	HPCI INOP Intentional for DCR 76-62		2	25
10-17-78	1125	10-17-78	2230	E41-C002 Steam leak repair E41-F029		11	5

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Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
11-15-78	0750	11-15-78	1730	E41(HPCI) for steam leak		9	40
12-3-78	2230	12-4-78	0115	HPCI INOP E41-F002		3	45
12-13-78	1455	12-16-78	0235	E41(HPCI) Repair steam leaks	2	10	40
1-9-79	2330	1-10-79	0350	HPCI Room high ΔT		4	20
2-9-79	1330	2-9-79	1645	HPCI Repair Steam Leak		3	15
2-26-79	0755	2-28-79	1705	HPCI Sys. Erratic turbine & flow control	2	9	50
3-27-79	0500	3-27-79	1600	PRELIMINARY HPCI Preventive Maintenance		11	
4-18-79	0600	4-19-79	1945	P41-F313B Repair Valve Operator	1	13	45
8-26-79	1410	8-30-79	1845	HPCI Shaft Replacement	4	10	
11-7-79	0530	11-9-79	0045	HPCI removed for service maint.	1	19	25
1-22-80	0660	1-22-80	1135	HPCI & RCIC INOP		5	25
5-30-80	0645	5-21-80	0240	HPCI tagged for maintenance		10	55
7-12-80	0815	7-12-80	1225	HPCI INOP isolated on Hi ambient temp.		4	10

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
7-25-80	1830	7-28-80	0445	HPCI was removed for overspeed test per MR#1-80-3933 and HNP-1-5289	2	10	15
8-18-80	0400	8-18-80	2145	HPCI on auto initiation, isolated within a few seconds after start		17	45
9-19-80	1940	9-19-80	2050	Performing HNP-1-3302, the min flow valve failed to close		1	10
9-19-80	2140	9-20-80	2020	HPCI tripped on Hi steam line ΔP when attempting to start system		23	40

PRELIMINARY

Table B : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Automatic Depressurization System (ADS)

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12/14/78	1515	12/14/78	1630	ADS Actuation Logic Test		1	15

PRELIMINARY

Attachment A

Table C : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Core Spray

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Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
7-4-76	0100	7-4-76	1315	Core Spray Sparger Alarm		12	15
3-4-77	0000	3-4-77	0945	Jockey Pump "A" Burned motor		9	45
3-5-77	0820	3-6-77	1020	Core Spray Pump "B" PM's (change oil)	1	2	
8-24-77	1050	8-24-77	1635	Repair Seal		5	45
5-5-78	2056	5-6-78	0045	Core Spray Pump Insp. "A" Faulty Pump control switch		1	59
8-12-78		9-15-78		E21-C002 (Core Spray) ACB's burned up	3*		
9-16-78		9-16-78		E21-C002A ACB OL's burned up	<1*		
9-18-78		9-28-78		E21-C002A ACB OL's burned up	10*		
10-1-78		10-5-78		E21-C002A ACB OL's burned up	4*		

* Estimate

Table C : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Core Spray

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
3-19-79	0740	3-19-79	1345	PM on Core Spray "A" Motor		6	5
8-15-79	1440	8-29-79	0730	Core Spray "A" Jockey Pump	7	7	30*
12-27-79	1300	1-1-80	2145	INOP A Core Spray loop to allow maint. to repair E21-F006A testable check valve (it sticks)	5	18	45
5-5-80	0852	5-5-80	1123	1E21-C001A Core Spray pump tagged for PM		2	21
5-6-80	0950	5-6-80	1140	Performing yearly PM on motor per HNP-1-6601		1	50
8-16-80	0530	8-16-80	2230	Maint repair valve-1E21-F3001B		17	
11-7-80	1325	11-7-80	1520	1E21-C001A "A" Core spray pump would not meet accepted criteria		1	55

PRELIMINARY

* Note: Unit in cold shutdown until 8/22/79

Attachment A

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Residual Heat Removal (RHR) System (LPCI) and Containment Cooling Mode

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
5-1-76	1231	5-1-76	1838	"A" RHR Loop Reset phase relay		6	6
5-8-76	0630	5-9-76	0840	To repair pump seal 1bSWP		2	10
6-3-76	0000	6-3-76	1345	RHR Loop "A" to repair E11-F060A		13	45
7-15-76	1000	7-15-76	1045	Rated Flow Test			45
7-20-76	1710	7-20-76	2255	RHR High flow switch failure		5	45
8-28-76	0835	8-28-76	1815	To repair relief valves		10	30
9-22-76		10-3-76	1545	ID PSW Pump INDP tagged out, repairing shaft busing blow seal operable			
9-24-76	0144	9-25-76	2015	See SCRAM report 76-22 Surveillance test	1	5	15
2-17-77	1800	2-19-77	0030	RHR SW Div. I Sys-Out of service	1	6	30
2-19-77	0040	2-19-77	1436	RHR SW Div. II Sys-Out of service		12	56
3-5-77	0650	3-5-77	1035	RHR Div. I out of service PM's change oil		3	45

PRELIMINARY

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Residual Heat Removal (RHR) System (LPCI) and Containment Cooling Mode

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
3-5-77	1105	3-5-77	1403	RHR Div. II out of service PM's change oil		3	56
5-27-77	0615	5-27-77	2000	Replace blanks in FDC & RHR cross ties RHR 'B' loop		14	45
6-2-77		6-22-77		RHR System INOP		18	10
7-19-77		7-20-77	1640	RHR pump oil change		1	55
7-20-77	0630	7-20-77	1055	RHR pump oil change		4	20
8-14-77	2045	8-16-77	1027	RHR 'B' Loop Sensor level Switch steam condensing MOD. out of service @ 0745		13	42
8-24-77	1050	8-24-77	1653	E11-C001B Repair Seal SW Pump		6	30
6-13-78	1050	6-13-78	1630	E11-C001A (unplug cooling line) RHR SW Pump		6	
6-14-78		6-14-78		E11-C001A A RHR SW Pump unstop motor cooler	<1*		
7-18-78	0015	7-18-78	1430	E11-C001A RHR SW Pump PM		14	15

*Estimated

PRELIMINARY

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Residual Heat REmoval (RHR) System (LCPI) and Containment Cooling Mode

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
8-3-78		8-4-78	1225	E11-C002C PM		4	30
1-31-78	0745	2-4-78	2340	A RHR SW Pump To replace seal water line	4*		
2-26-78	0755	2-26-78	1410	Tagging RHR System II for Maint. MR78-631 and DCR 76-75		6	15
1-14-79	0440	1-5-79	0840	Install orifices in RHR SW Sys.	1	4	
1-27-79	0630	1-31-79	0600	"A" loop RHR loop LLRT E11-F015A	3	23	
8-12-79	1300	8-12-79	1630	RHR - Shutdown cooling repair E11-F029		3	30
8-12-79	0935	8-12-79	1405	RHR SD Cooling made out of service for maintenance to repair E11-F029		3	30
8-19-79	1705	8-19-79	2230	RHR & PSW out for divers		5	25
9-24-79	0815	9-24-79	1615	1E11-C002 for PM		8	

PRELIMINARY

*Estimated

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Residual Heat Removal (RHR) System (LPCI) and Containment Cooling Mode

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	**Time**	**Date**	**Time**		**Days**	**Hours**	**Minutes**
9-27-79	0645	9-27-79	1405	1E11-C002D for PM		7	20
12-11-79	2200	12-13-79	2359	E11-F015B Leaks by	2	1	59
12-12-79	0945	12-12-79	1125	PSW Pumps "B" INOP and "B" RHR loop in operation all 3 diesels must be operable "C" diesel generator INOP due to fuel oil storage tank oil specifications out of limits		1	40
2-7-80	0430	2-7-80	1520	1E11-C001D Maint. Install strainers		10	50
4-14-80	0840	4-14-80	0915	IR-24-S018B was de-energized while IR44-S003 was tripped, BKR on inverter output would not open so alternative supply to S018B could be closed			35
4-22-80	0730	4-22-80	1350	Tagged out "B" RHR pump for maint. to perform and change oil per MR-1-80-942		6	20
5-24-80	1400	5-25-80	1125	1E11-F015A & E11-F017A both closed due to valve seat leaking		21	25

Attachment A

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Residual Heat Removal (RHR) System (LPCI) Containment Cooling Mode

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
7-11-80	2045	7-11-80	2140	LPCI inverter tripped due to HI ambient temp in LPCI inverter room			55
7-31-80	0730	7-31-80	1215	LPCI inverter tripped due to over temp		4	45
8-8-80	0605	8-8-80	1025	1E11-C002B & D tagged out PM on 1E11-N040 ISO valve		4	20
8-8-80	0740	8-8-80	1025	HNP-1-3162 RHR Oper. for "B" loop (main) & valve		2	45
8-8-80	0740	8-10-80	1525	1E11-F015A Valve INOP. valve failed to open	2	15	45
10-22-80	1150	11-22-80	1655	1E11-C002C RHR SW Pump tagged out for PM (HWP-1-6005)		5	5
10-23-80	1120	10-23-80	1510	ID RHR Pump tagged out for PM 1E11-C002D		3	50

PRELIMINARY

Table E : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: RHR Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
6-12-78	2130	6-14-78	1310	"A" RHR SW Pump	1	15	40
8-12-79	1500	8-22-79	0435	B&D RHR SW Pump failed rated flow	9	13	35
8-16-79	0600	8-24-79	1400	"A" RHR Pump did not meet rated head	8	8	
8-20-79	1830	8-24-79	1850	"C" RHR SW pump did not meet rated head	4	10	
9-7-79	2010	9-9-79	1545	RHR SW pumps, A, B&D, INOP	1	19	35
1-13-80	2300	1-14-80	0145	(3) RHRSW pumps found to be INOP per HNP-3167		2	45
1-14-80	0030	1-18-80	1630	1E11 "A" RHRSW pump per HNP-1-3167	4	15	
2-5-80	1215	2-5-80	1635	1E11-C001A Maint to install filter in cooling H_2O line		4	20
2-6-80	0610	2-6-80	1025	1E11-C001B (maint) to install filter in cooling H_2O line		4	15
2-6-80	1035	2-6-80	1710	1E11-C001C silt removal modif.		7	25
5-15-80	1500	5-15-80	1640	1 "A" RHR SW pump tagged out for cooling water modifications per DCR-80-129, MR#1-80-2026		1	40

PRELIMINARY

Table E : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: RHR Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
5-15-80	1645	5-15-80	1855	1C RHR SW pump tagged for maint. to perform cooling water modifications per DCR-80-129, MR1-80-2026 and MR1-80-2454 & HNP-1-11011		2	10
5-16-80	0850	5-16-80	1940	1E11-C001A&C tagged out for DCR-80-129 modification of motor cooling H_2O pump INOP per CL-#1-80-342		10	50
5-16-80	1955	5-17-80	0205	Tagged out 1E11-C001 B&D RHR SW pumps motor cooling modifications per DCR 80-129 & HNP 1-11011		6	10
5-17-80	0205	5-17-80	1100	When clearing clearance #1-80-344 it was found that BKR for 1E11-C001B would not rack in		8	55
6-11-80	1350	6-11-80	2200	1E11-C001D INOP, motor burned up		9	10
6-12-80	1950	6-17-80	1420	1E11-C001D pump INOP motor has been removed for repairs	4	18	30
8-7-80	2000	8-8-80	0005	"B" RHR SW flow transmitter 1E11-N007B INOP while perform HNP-1-3167		4	5

PRELIMINARY

Table E : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: RHR Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
9-6-80	1245	9-20-80	0945	RHR SW Pump 1E11-C001D failed HNP-1-3167, RHR pump operability and rated flow pump vibration in the action range (east 2.2 and south 1.85)	13	21	
10-9-80	1330	10-9-80	1555	Tagged 1E11-C001A RHR Service water pump, for oil change		2	25
10-10-80	0710	10-10-80	0950	RHR SW pump 1-B change oil in motor		2	40
10-10-80	1145	10-10-80	1930	RHR SW 1-C tagged for oil change		7	45

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
1-9-76	0530	1-10-76	1600	PSW Div. II	1	8	30
1-26-76	0600	1-26-76	0820	"C" PSW Pump DCR on Min flow valve		2	20
2-8-76	0315	2-18-76	1420	"C" PSW Pump INOP, Maintenance	10	10	50
5-6-76				Div I "C" PSW, Maintenance		6	
5-15-76				Div II "B" PSW, Maintenance		6	30
5-16-76		5-19-76		Div I "A" PSW, Maintenance	3	18	
5-21-76				Div I "D" PSW, Maintenance		14	7
8-4-76	2315	8-5-76	0150	"B" PSW, Maintenance		2	35
8-10-76	0740	8-10-76	1330	"C" PSW, Maintenance		5	50
8-20-76	0315	8-22-76	1650	"B" PSW, Maintenance	2	13	35
9-22-76	2230	10-3-76	1545	"D" PSW, Maintenance		16	50
10-1-76	0000	10-3-76	1545	Div II PSW, Maintenance	2	15	40
11-12-76	0715	11-20-76	1435	Div I PSW, Maintenance	8	7	20

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
2-15-77	1935	2-17-77	0340	PSW Div II B&D Pump		31	40
2-16-77	1430	2-17-77	0215	Service Water out for Reinforcement pads		11	45
2-17-77	1230	2-18-77	0150	PSW Div I A&C Pump		13	20
5-28-77	0910	5-29-77	0710	PSW Div I, Maintenance		21	40
8-12-77	0435	8-12-77	0600	"D" PSW, Maintenance		1	30
8-18-77	0435	8-18-77	1725	"D" PSW, Maintenance		8	35
8-29-77	0400	9-4-77	1415	"D" PSW, Maintenance		10	45
9-16-77	0200	9-26-77	1000	"A" PSW, Maintenance		4	55
10-9-77	1130	10-09-77	220[illegible]	"A" PSW, Maintenance		11	25
10-24-77	0545	10-30-77	1040	"B" PSW, Maintenance		4	35
10-30-77	1800	11-1-77	1035	"C" PSW, Maintenance	1	16	35
11-2-77	1330	11-2-77	1555	"A" PSW, Maintenance		2	25

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
2-21-78	1050	2-21-78	1430	PSW pump 2D out for PM		4	
3-4-78	0940			PSW tagged out for ACT #5, 10, 11			
3-30-78	1525			1 C PSW pump racked out to do maint. on BKR.			
4-21-78	0800	4-21-78	1000	C PSW pump leak on Main Flow Line.		5	
4-21-78	1000	4-21-78	1300	B PSW pump inop		2	
6-7-78	0615	6-7-78	1430	A&C PSW pump inop for operability test.	8	15	
6-9-78	2230	6-13-78	1650	PSW Pump D (P41-C001D) will not pump.	3	18	20
6-15-78	0530	6-19-78	0812	P41-D104A PSW to Air conditioning	2	2	42
6-19-78	0940	6-19-78	1340	P41-D104B PSW to cir. Air Cond.		4	
7-20-78	0900	7-26-78	1930	P41-C001A Low flow. PSW pump	6	16	30
7-22-78		7-26-78		P41-C001A PSW Pump (Low flow pump)	4*		
8-4-78	0655	8-4-78	1255	1D PSW Pump INOP		6	

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
10-5-78		10-6-78		P41 - F313 Repair discharge line water leaks.	1*		
10-10-78	0230	10-11-78	1825	P42 - C002 Standby PSW Pump INOP	1	12	
4-10-79	0510	4-10-79	1655	"A" PSW Pump P.M. on motor & BKR		11	45
4-7-79				"B" PSW INOP		18	30
5-2-79	0545	5-5-79	0410	"C" PSW 5 yr. P.M.	2	23	25
5-2-79	0710	5-9-79	1655	"B" PSW INOP 5 yr. P.M.	6	9	45
7-31-79	1300	8-5-79	1045	PSW Pump Seal Repair	3	21	15
11-2-79	0930	11-2-79	2355	1C PSW Pump to Maint. Replace Bad Seal		14	25
11-14-79	0145	11-14-79	2000	1D SW Pump INOP Repair Shaft Seal		18	15
11-21-79	1110	11-26-79	1650	PSW Pump is not pumping and pulling less than rated amps	5	5	40
11-22-79	0430	11-22-79	0500	PSW Pump A failed to pass HNP-1-3182 rated flow			30

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
11-22-79	0430	11-22-79	0600	PSW Pump 1C failed to pass HNP-1-3182		1	30
11-22-79	0430	11-22-79	0500	A&C PSW Pumps failed to pass HNP-1-3182			30
12-11-79	2125	12-13-79	1000	PSW "B" failed operability test	1	1	25

PRELIMINARY

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

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Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12-16-79	1450	12-23-79	1500	Standby PSW Pump & IP41-C001D PSW Pump INOP	7		10
12-16-79	1450	12-18-79	1100	Standby PSW pump, PSW pump & 1C D/G being INOP	10	21	10
12-16-79	0225	12-23-79	1500	D PSW pump INOP for Maint.	7	12	35
12-16-79	1140	12-17-79	0415	D PSW Pump INOP, C D/G failed to start		16	15
12-23-79	1530	12-24-79	0135	1D PSW pump INOP for overhaul @ 1450 the standby PSW Pump INOP tripped during, HNP-1-3801 unit placed in cold S/D @ 0415		10	5
12-24-79	0135	12-28-79	1625	Standby PSW pump INOP tripped during Surv, HNP-1-3801 IP41-C002	4	14	50
1-14-80	0920	1-22-80	1745	Tagged PSW pump for maint.	8	8	25
1-14-80	1420	1-18-80	1530	Failure 1B PSW pump to pass HNP1-3182 & standby pump INOP	4	1	10

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
2-4-80	1021	2-4-80	1620	Standby Plant SW pump INOP due to electrical control power not being Class E.		6	1
2-18-80	2100	[illegible]-19-80	0025	1P41-C001A PSW pump INOP per HNP-1-3182		3	25
2-19-80	0830	3-11-80	2110	[illegible] maint.	21	12	50
2-26-80	2015	2-26-80	2207	Standby PSW pump INOP after HNP-1-3801 while PSW pump was INOP		1	52
2-29-80	0445	2-29-80	1330	1D PSW pump repair seal water leak		8	45
2-29-80	1140	2-29-80	1720	1C D/G INOP & PSW pump INOP		5	40
2-29-80	0445	2-29-80	1330	1D PSW pump to repair water seal leak while 1A PSW PUMP IS INOP		8	45
5-8-80	1215	5-8-80	1615	PSW Pump 1P41-C001C to maint to change oil		4	
5-9-80	0845	5-9-80	1000	1P41-C001B PSW pump for maint.		1	15

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Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Plant Service Water System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
5-9-80	1215	5-9-80	1340	1P41-C001D for PM		1	25
5-9-80	2110	5-16-80	1930	1BPSW pump failed to pass pump operability HNP-1-3182	6	22	20
5-22-80	0530	5-22-80	1230	1P41-C001D PSW pump for maint.		7	
6-30-80	1125	7-4-80	1220	Standby PSW pump INOP to repair Seal and Bearing	4	1	5
8-19-80	0445	8-19-80	1500	A PSW pump Leaking Seal		10	15
9-10-80	0545	9-28-80	1315	1A PSW pump for shaft seal repair	18	7	30
9-9-80	0430	9-9-80	1200	1D PSW pump INOP to repair seal leak		7	30
10-11-80	0415	10-21-80	1500	1P41-C001C, 1C PSW pump tagged out due to vibration	10	11	5

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Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
3-5-76	0550	3-15-76	2206	Mod to coolant jacket system		16	44
6-4-76	1200	6-4-76	2000	1 "B" D/G Run Pre-op on batteries		7	30
6-7-76	0800	6-7-76	1200	Repair Fuel Injectors		4	
6-26-76	2010	6-26-76	2215	Tripped on Emerg. ENG Shutdown 1 "C" D/G		2	5
6-27-76	0730	6-27-76	1336	Trip switch on high lube oil temp 1 "C" D/G		6	6
8-5-76	0045	8-5-76	1310	Supply BKR tripped		12	25
8-26-76	0652	8-26-76	1900	Maintenance- change oil		12	8
8-27-76	0605	8-27-76	2210	Maintenance - change oil		16	5
8-29-76	0900	8-29-76	2130	D/G 1 "C" D/G Batteries pilot cell low specific gravity		12	30
10-5-76	0845	10-5-76	1435	1 "C" D/G Fix fuel line		5	50
11-6-76	0705	11-6-76	1520	1 "C" D/G Maintenance		8	15
11-25-76	0925	11-25-76	1550	Maint on lube oil pump		6	25

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Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12-6-76	0740	12-6-76	2150	Inspect Air Blower		14	10
12-6-76	2315	12-7-76	1740	Inspect Air Blower		18	20
12-7-76	2330	12-8-76	1250	1 "C" D/G Inspect air blower		13	20
12-8-76	0000	12-8-76	1250	Inspection 1 "B" D/G		12	50
12-18-76	0840	12-18-76	1225	Maintenance 1 "A" D/G		3	45
2-6-77	0700	2-8-77	11[illegible]	Service water out of service '1C'	2	4	15
2-17-77	1231	2-18-77	1500	Service water out of service '1C'		14	15
2-26-77	1215	2-26-77	1545	Repair oil leak '1C'		3	30
5-23-77	1243	5-23-77	1600	INOP Surveillance Test '1A'		3	17
5-24-77	0520	5-24-77	1210	Cam Inspection '1B'		6	50
5-24-77	1345	5-24-77	1733	'1C' D/G Inspect Cam		3	45
6-7-77	1430	6-9-77	1500	Cam-shaft inspection '1A' D/G	2		30
6-10-77	0620	6-11-77	1515	'1C' D/G Inspect cam		32	55
6-13-77	1045	6-15-77	2100	'1C' D/G Inspect cam	2	12	15

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Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
6-13-77	1430	6-15-77	2130	Camp Inspection '1B' D/G	2	7	
7-16-77	0655	7-16-77	1755	'C' D/G Out of service - Test PM's and test Cal.		16	
7-23-77	0612	7-23-77	1640	PM's Change oil '1A'		10	28
7-30-77	0530	7-30-77	1845	Change oil (PM) '1B' D/G		13	15
8-6-77	0610	8-6-77	1040	Broken timer '1A' D/G		4	30
8-12-77	0555	8-12-77	1726	Voltage Reg Problems '1A' D/G		11	30
8-18-77	1350	8-22-77	1930	Bad bearing '1B' D/G	4	5	50
9-1-77		9-1-77		D/G Out		3	10
9-2-77	2330	9-3-77	1740	Rebuilding pump '1A'		18	15
10-4-77	1245	10-4-77	1515	INOP for test shop '1A' D/G		2	30
10-5-77		10-5-77		D/G Out		9	30
11-20-77		11-20-77		D/G Out		7	45
11-26-77	0850	11-26-77	1307	Failed to start '1A' D/G		4	43
12-6-77	1430	12-9-77	1940	Pre-op for Unit II '1B' D/G	3	5	10

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Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	**Time**	**Date**	**Time**		**Days**	**Hours**	**Minutes**
12-17-77	0234	12-17-77	1210	Out of service for Servomotor Replacement '1B' D/G		9	24
1-16-78	1430	1-19-78	2100	R43-S001B - Maint inspecting generator bearings	3	6	30
3-17-78	0955	3-17-78	1310	R43-D/G 1B replace D/G battery chargers		3	15
3-25-78	0800	3-25-78	1205	R43-S001B D/G tagged for pre-op		4	5
6-9-78	1030	6-13-78	1715	R43-S001B D/G Repacking governor	4	16	45
6-13-78	1346	6-13-78	1415	B D/G Supply breaker to bus.			29
6-14-78	1010	6-14-78	1415	A D/G Output to BKR		3	25
8-5-78	1015	8-5-78	2310	R43-S001B PM & Investigate Pre-Lube Problem		12	55
8-14-78	0600	8-15-78	1825	1B D/G out for PM	1	12	25
9-2-78	0600	9-2-78	1335	R43-S001C D/G INOP		8	
9-27-78	0110	9-28-78	1645	R43-C001C 1B D/G (Air compressor Leaking Relief Valve)		16	45
10-28-78	1425	10-28-78	2000	R43-S001C Blown oil pressure gauge (repaired)		5	35

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

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Outage in Effect		Outage Terminated		Cause	Total Time		
Date	**Time**	**Date**	**Time**		**Days**	**Hours**	**Minutes**
11-12-78	0630	11-12-78	1700	R43-S001B (operable @1700) DYB (test shop) MR78-32474-3654		10	30
2-4-78	0730	2-4-78	1155	B D/G INOP for test shop - to calibrate SW flow		4	25
2-24-78	1200	2-24-78	2050	B D/G to run pre-op for PSW pump for B D/G		8	50
3-26-78	1130	3-26-78	1600	Tagged 1 C D/G for HNP-1-3804		4	30
4-1-78	0630	4-2-78	0620	B D/G INOP		23	50
4-28-78	1245	4-28-78	1730	1 C D/G INOP to Maint for walk-on Relief Valve For 1-C-2 pump		4	45
5-18-78	1430	5-18-78	1610	1B D/G INOP		1	40
5-22-78	1350	5-22-78	2130	1 B D/G INOP to preform HNP-2-3804		7	40
5-24-78	1450	5-25-78	0150	B D/G tagged out to support UNITS LSFT on ECCS		11	
5-29-78	0925	5-30-78	0145	1B D/G INOP for units to work on PM.		16	20

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated			Total Time		
Date	Time	Date	Time	Cause	Days	Hours	Minutes
6-4-78	0030	6-4-78	2025	B D/G INOP to perform MR-1-78-1731		19	55
6-4-78	2345	6-5-78	1945	1 A D/G INOP		20	
7-2-78	1650	7-3-78	0335	B D/G INOP temp switch broke		10	40
7-28-78	0845	7-28-78	1645	1 C D/G INOP		8	
9-28-78	0248	9-29-78	1805	1 A D/G INOP	1	15	17
10-30-78	0725	10-30-78	1300	B D/G Tagged INOP		5	35
1-6-79	0417	1-6-79	0611	Repair 3/way lamp control valve		1	56
1-9-79				Repair relief valve '1A' D/G			
1-16-79				Repair 'B' pump D.G			
8-9-79	0400	8-9-79	1745	1B D/G Out of Service for maint.		13	45
9-18-79	0130	9-18-79	2130	A D/G PM		20	

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Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	**Time**	**Date**	**Time**		**Days**	**Hours**	**Minutes**
10-11-79	0315	10-12-79	2000	Made "1C" D/G INOP to perform DCR-77-208 & yearly PM	1	16	45
10-16-79	0420	10-16-79	0801	"B" D/G INOP Maint. to paint exhaust		3	40
10-17-79	0755	10-17-79	1730	1B D.G out for maint to paint exhaust line		9	30
10-22-79	0515	10-27-79	1300	1C D/G INOP for Maint. to repair Discharge check Valve (2P41-F311C)	5	7	45
10-22-79	0810	10-22-70	1705	1B D/G out for PM		9	
10-26-79	0655	10-26-79	1600	1A D/G tagged for maint to paint exhaust header		9	5
11-2-79	2000	11-3-79	0150	1B D/G Tripped during surv. due to 2P41-C002		5	50
11-21-79	1950	12-11-79	1620	PSW pump failed rated flow 2P41-C001D	20	18	30
12-13-79	0730	12-13-79	1830	INOP due to PSW out of service		11	
12-13-79	0730	12-13-79	1830	Failed to start "C" D/G		11	

PRELIMINARY

Attachment A

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12-16-79	1450	12-28-79	1625	Standby plant service water pump (2P41-C002) tripped	12	1	35
1-12-80	0720	1-12-80	1305	"1C" D/G for maint.		5	45
1-14-80	0920	1-22-80	1745	Standby PSW pump, to maintenance to repack it	8	8	25
1-30-80	1130	1-31-80	0530	2P41-C002, standby PSW pump failed HNP-1-3801 D/G manual start for 1B D/G inservice test for standby PSW pump		18	
2-4-80	1021	2-4-80	1620	Standby [illegible] pump MCC being non-Class [illegible] C002)		5	53
2-26-80	2015	2-26-80	2207	2P41-C002, 1 standby PSW pump INOP, failed to pass HNP-1-3801		1	52
3-22-80	1213	3-22-80	1715	1C D/G failed to start		5	2
4-5-80	1930	4-6-80	1030	1 "C" D/G tagged to work on stop		15	
4-15-80	2200	4-16-80	2348	1 "B" D/G tagged out for maint. elected to perform work on 2F416ov Buss Ct. Circuits	1	1	48
4-28-80	0430	4-29-80	1500	Tagged "1C" D/G for PM	1	10	30

PRELIMINARY

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 1

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
4-29-80	0430	4-29-80	1230	"1C" D/G out and performing HNP-1-3162 RHR Mov. operability and 1E11-F016A wouldn't operate		8	
6-15-80	0030	6-15-80	0740	1C D/G INOP		7	10
6-28-80	1101	6-28-80	1915	1B D/G INOP		8	14
10-1-80	0550	10-1-80	1530	1A D/G INOP for maint.		9	40
10-6-80	0330	10-7-80	17[illegible]0	1B D/G Tagged for PM		14	10
10-28-80	0850	10-31-80	0115	D/G "B" for PM	2	16	15
10-29-80	0930	10-29-80	1740	2P41-C002/R43 S001B 1B D/G INOP with standby PSW pump		1	55

PRELIMINARY

Attachment A

ATTACHMENT B

TO

GP-R-33009

DETAILED SUMMARY OF ECCS OUTAGES

FOR HATCH UNIT 2

(7/1/78 - 12/1/80)

PRELIMINARY

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
10-22-78	1000	10-23-78	0630	2E41-F001 Motor burned up		21	30
11-18-78	1035	11-18-78	1135	2P41-F303B PSW Screen cleaned		1	
11-19-78	2240	11-20-78	1700	HPCI out for DCR 78-436		20	20
7-24-79	0735	7-24-79	1830	2E41-FOO2 valves are closed & tagged for test shop placement of pressure gauge on steam stop valve		10	55
7-25-79	1017	7025-79	[illegible]	Maint. to be performed on 2E41-F001 valve tagged & BKR tag open also aux oil pump BKR		3	8
7-26-79	0755	7-28-79	1840	HPCI tagged out for maint on HPCI turbine stop valve		2	10

PRELIMINARY

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
7-30-79	1350	7-30-79	2140	2E41-F041 stuck in mid position Torus suction-mov.		7	50
10-14-79	1650	10-17-79	0340	Isolating HPCI steam supply and declaring HPCI INOP due to steam leaks on isolation valves to inlet drain pot. HPCI torus suction valve 2E11-F041 INOP, Burned-up motor	2	10	50
10-18-79	0800	10-18-79	[illegible]	Turned power off to 2E41-F006 with valve closed, for isolation of 2B21-F076A		2	40
10-25-79	1307	11-5-79	0525	[illegible] valve closed & tagged due to [illegible]F002 being INOP.	10	16	18
11-26-79	2200	11-27-79	2130	HPCI flow indicator 2E41-R613 INOP, reading <0 when pump was running		23	30
11-29-79	1545	11-30-79	0415	Test shop replacing GE555 ΔP transmitter with Rosemont 1151 ΔP transmitter per DCR-79-463 & HPCI auxiliary oil pump not auto starting also trips BKR		12	30

PRELIMINARY

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12-12-79	0735	12-12-79	1620	HPCI tagged oil pump out for PM		9	15
12-13-79	0420	12-14-79	1248	HPCI isolated for steam leak repair 2E41-F002 & F003 closed & tagged	1	8	30
12-23-79	0410	12-23-79	2050	2E41-C002 HPCI turbine tagged per clearance #2-79-1043 to change out lube oil		16	40
12-24-79	0715	12-24-79	0800	HPCI discharge line (pump discharge) not full of water			45
12-25-79	0935	12-25-79	1115	Steam observed in discharge line while venting		1	40
12-28-79	0925	12-28-79	1040	2E41-F006 leaking causing water in discharge line to flash to steam when venting line.		1	15
12-28-79	0511	12-28-79	0550	Received "HPCI" suction pressure HI and upon venting pump discharge line found that this was not full of water (caused by 2E41-F006 leaking)			45

PRELIMINARY

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: High Pressure Coolant Injection(HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
12-31-79	0005	12-31-79	0032	While performing standing order DER 79-64 steam found in HPCI discharge line			27
1-17-80	1155	1-17-80	1340	HPCI "Topaz" inverter failed		1	45
1-18-80	0535	1-18-80	1015	2E41-K616, INOP, this rendered the flow controller INOP		1	40
1-22-80	1145	1-22-80	[illegible]05	2E41-K601, to test shop for calibration, HPCI Sq root converter (HNP-2-5213)		1	20
1-30-80	1015	1-31-80	2103	2E41-C002 HPCI, Remove isolation	1	10	12
4-22-80	1900	4-22-80	1910	HPCI and RCIC INOP simultaneously			10
4-22-80	1900	4-24-80	1150	HPCI INOP due to battery ground	1	16	50
5-7-80	2238	5-14-80	0930	2E41-F006 motor burned up. This is injection insolation	6	10	22
5-30-80	1255	6-5-80	0005	HPCI INOP Steam leak potentially breaking down - HPCI mov. motors.	5	11	10

PRELIMINARY

Table A : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: High Pressure Coolant Injection (HPCI) System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
6-26-80	0300	6-27-80	1730	HPCI INOP to low pump suction pressure discovered while performing HNP-2-3303J test to CST valve 2E41-F008 failing in open position and min. flow valve 2E41-F012 cycling open & close	2	14	30
7-11-80	0455	7-12-80	0330	Trying to manually start HPCI and 2E41-F006 would not operate		22	35
8-10-80	0745	8-10-80	1150	2E41-F042 HPCI Suction from torus tagged closed to check valve motor, BRK + limit switches		4	5
8-27-80	0903	8-27-80	1930	HPCI removed from service to check battery ground		10	27
8-28-80	0910	8-28-80	1710	HPCI removed from service to repair seal waterline leak		8	
9-9-80	0900	9-9-80	1835	HPCI, RCIC, INOP & CS "B" RCIC - Repacking 2E51-F008 HPCI-2.5% water in oil CS - tagged out for DCR		9	35
9-23-80	0400	9-25-80	1845	HPCI tagged out for maint. to repair pump seal	2	4	45

PRELIMINARY

Table C : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Core Spray System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
9-6-79	1030	9-7-79	1600	"A" Core spray pump 2E21-C001A tagged out for yearly PM	1	5	30
10-4-79	0100	10-5-79	1010	CS Pump 1B removed for PM MH2 79-4240	1	9	10
10-23-79	0710	10-23-79	1400	2E11-C002B Pump INOP for PM		7	10
3-2-80	0030	3-3-80	1000	Tagging out core spray loops for LLRT clearance sheet NU#2-80-153 and 2-80-154	1	9	30
4-13-80	0445	4-15-80	0235	Loop Core Spray out of service [illegible] HPCI system.	1	21	50
8-5-80	0545	8-5-80	1300	Core Spray pump tagged out for PM per MR#2-80-2974		7	15
8-16-80	0010	8-19-80	1652	"B" loop core spray tagged out for 2G51 torus c/v modifications PCR 79-386	3	16	42
9-8-80	0020	9-9-80	1835	Tagged loop B core spray for torus purification modification per MR 2-80-2984 and PCR 79-386	1	18	15
10-27-80	1103	10-27-80	1330	"B" Core spray for PM		2	27
11-1-80	1030	11-1-80	1808	"A" loop LLRT		7	38

PRELIMINARY

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Low Pressure Coolant Injection (LPCI) Subsystem of the RHR System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
7-21-78	1400	8-3-78	1430	2E11-C001A RHR Service wtr pump maint.	13		30
8-5-78	1240	8-28-78	1000	"A" RHR ht. exch. outlet valve maint.	23	14	40
10-20-78	0630	10-20-78	1850	2E11-F068 A&C maintenance		12	20

PRELIMINARY

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Low Pressure Coolant Injection (LPCI) Subsystem of the RHR System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
10-8-78	0630	10-9-78	1345	RHR SW pump INOP	1	5	30
11-14-78	1845	11-14-78	2330	Repair 2E11-F009		4	45
10-24-78	1220	10-24-78	1730	2E11-C001C collect new data		5	10
11-16-78	1000	12-1-78	1955	2E11-F047A repair	15	9	55
11-23-78	2100	12-1-78	2100	2E11-F074B repair motor bad	7		
12-8-78	0700	12-8-78	0722	R44 LPCI inverter INOP			22
12-23-78	0740	12-24-78	0610	2E11-F075A motor burned		22	5
10-8-79	0840	10-9-79	0215	2E11-C002A tagged out to perform PM		17	35
10-18-79	0730	10-19-79	1322	RHR pump 2C(E11-C002C) to perform PM per MR2-79-4246		5	52
11-3-79	2230	11-4-79	0920	Logic in 2E11-F004C intake valve closed when 2E11-F006C is open. But logic is bad & F006C is closed and 2E11-F004C logic still thinks its open. Thus, it is intlk'd closed preventing LPCI pump from having suction source.		10	50

PRELIMINARY

Attachment B

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Low Pressure Coolant Injection(LPCI) Subsystem of the RHR System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
11-6-79	0700	11-6-79	1430	2E11-C002D out for yearly PM, change motor oil		7	30
11-14-79	1245	11-14-79	1345	LPCI inverter out to replace some blown capacitor fuses		2	
11-17-79	1010	11-18-79	1030	R44-S003 LPCI nverter tripped	2		20
11-18-79	[illegible]315	11-18-79	1355	Removal of 2R44- 003 PCI Inverter			40
4-24-80	0445	4-24-80	1150	2R440 Inverter (LPCI) out of service to investigate possible [illegible]250 UDC battery ground problems.		7	5
5-14-80	1415	5-15-80	1115	RHR pump 2E11-C002D suction valve 2E11-F006D and 2E11-F004D both are closed, will not open. DRHR pump then racked out to prevent starting with no suction source.		21	
10-8-80	0900	10-8-80	1325	2C pump tagged for PM		4	25
10-10-80	0835	10-10-80	1235	2D RHR P/M		4	
10-15-80	1230	10-15-80	1440	"A"RHR pump for PM		2	10

PRELIMINARY

Table D : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Low Pressure Coolant Injection (LPCI) Subsystem of the RHR System

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
10-16-80	0845	10 16-80	1115	PM on motor		2	30
10-31-80	1600	11-1-80	0205	LLRT on "B" LOOR of RHR		10	5
11-1-80	0400	11-1-80	0920	LLRT		5	20
11-1-80	1815	11-2-80	0205	"A" loop tagged for LCRT		4	50
11-7-80	0910	11-7-80	1015	RHR ht.exchanger outlet tripped		1	5
3-1-80	1030	3-2-80	0015	2E11-"A" of RHR tagged out for LLRT		14	45

PRELIMINARY

Attachment B

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Plant Service Water

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
11-17-78	0825	11-17-78	1800	2 "D" PSW Pump out		7	35
11-2-79	2000	11-3-79	0150	1B D/G Tripped during surv. due to 2P41-C002		5	50
7-21-79	1630	7-21-79	1935	A vent valve, just down stream of of 2E11-F068A broke off flush with the main RHR SW line, forcing tag out of RHR SW loop while repairs completed	1	10	30
10-13-79	1430	10-13-79	1800	RHR SW Pump "C" unable to pass HNP-2-3167		3	30
10-31-79	1900	11-17-79	1730	PSW Pump failed to pass rated flow	16	22	30
11-1-79	0500	11-1-79	1530	RHR SW pumps A&C for cleaning of cooling water line		10	30
11-17-80	1830	11-22-80	0220	PSW Pump 2P41-C001B failed rated flow	4	7	50

PRELIMINARY

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Plant Service Water

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
11-21-80	1950	11-22-79	0220	PSW Pump Failed flow (2P41-C001D)		6	30
11-21-79	1950	12-11-79	1620	PSW Pump failed rated flow 2P41-C001D	20	18	30
12-13-79	0730	12-13-79	1830	PSW Out of service		11	
12-16-79	1450	12-28-79	1625	Standby plant service water pump (2P41-C002) tripped	12	1	35
1-14-80	0920	1-22-80	1745	Standby PSW pump, to maintenance, to repack it	8	8	25
1-30-80	1130	1-31-80	0530	2P41-C002, standby PSW pump failed HNP-1-3801 D/G manual start for 1B D/G inservice test on standby PSW pump		18	
2-4-80	1021	2-4-80	1620	Standby PSW pump MCC being non Class E (2P41-C002)		5	53
2-12-80	0610	2-13-80	1610	(2E11-C001B) RHR SW pump INOP to repair seal leak	1	10	
2-16-80	0530	2-16-80	1700	2E11-C001C tagged to maint to PM RHR SW pump		11	30
2-26-80	2015	2-26-80	2207	2P41-C002, 1 standby PSW pump INOP, failed to pass HNP-1-3801		1	52

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Plant Service Water

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
4-15-80	2213	4-16-80	2150	4160 V Bus for maint PSW 2C & 2D & standby service H_2O pump made INOP		23	30
5-6-80	1152	5-6-80	2045	Pump tagged for oil change		8	53
5-8-80	0800	5-8-80	1645	Pump tagged for oil change and repair 2P41-F330D		8	45
5-21-80	1415	5-21-80	2000	2E11-C001B & D RHR SW pump S - out for maintenance to repair Div II air release valve		5	45
5-30-80	0500	5-30-80	1645	PSW pumps (2P41-C001D) tagged out for maint. to replace bad seal (pump) - per clearance 2-80-714		11	45
6-8-80	0730	6-15-80	1556	RHR Sw pump 2A (2E11-C001A) was made INOP under MR 2-80-24 to remove the motor and replace it on Unit-1"D" RHR SW Pump	7	8	26
6-29-80	0955	6-29-80	1410	2P41-C001A tagged out for maint to perform HNP-2-6200 yearly PM		4	15
6-29-80	0430	6-29-80	0950	2P41-C001C pump tagged out for maint.for PM per HNP-2-6200		5	20

PRELIMINARY

Table F : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Plant Service Water

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
8-3-80	0500	8-3-80	1700	RHR S/W 2C would not trip core spray		12	
9-16-80	1200	9-21-80	1845	Pump BKR was racked out to investigate tripping problem and unstick discharge check valve	4	6	45
9-23-80	0505	9-23-80	1530	Plant Service water pump 2P41-C001D tagged for maint. repair seal leakage		10	25
10-29-80	0930	10-29-80	1740	2P41-C002/1R43-S001B 1B D/G INOP with standby PSW pump		1	55

PRELIMINARY

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
9-14-78	0520	9-14-78	1015	2C Air Comp. & R43-C001A		4	55
9-14-78	1220	9-15-78	0730	2A D/G and Comp. INOP		19	10
9-16-78	1135	9-16-78	1610	2A D/G Air Comp.		5	30
10-28-78	0630	11-13-78	1240	2C D/G Failed to start	15	6	10
8-1-79	0215	8-2-79	1245	2A D/G Made INOP for implementation of DCR-79-198	1	3	5
8-9-79	0400	8-9-79	1745	D/G out of service for maint.		13	45
8-27-79	1230	8-27-79	[illegible]230	RHR SW Subsystems INOP loss of cooling water to pump (B&D Pump)		10	
10-22-79	0515	10-27-79	1300	C D/G INOP for Maint. to repair Discharge check valve (2P41-F311C)	5	7	45

PRELIMINARY

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Attachment B

Table G : SYSTEM COMPONENT OUTAGES FOR HATCH UNIT 2

System: Diesel Generators

Outage in Effect		Outage Terminated		Cause	Total Time		
Date	Time	Date	Time		Days	Hours	Minutes
10-23-79	0746	10-23-79	1610	D/G Maint. to paint exhaust		9	
10-24-79	0905	10-24-79	2200	2C D/G out Maint. to paint exhaust line		13	
10-25-79	0725	10-25-79	1930	2A D/G out Maint. to paint exhaust line		12	
11-13-79	2213	11-14-79	0530	Performing HNP-2-3801 2C D/G after 11 minutes starting time tripped on high crank case pressure on (2) start attempts		7	17
12-28-79	0510	12-28-79	1230	Running HNP-2-3801 D/G 2A failed to start		7	20
1-2-80	0530	1-4-80	1520	2A D/G tagged for maint. 2R43-S001A	2	9	20
1-23-80	0820	1-25-80	1755	2R43-S001C 2C D/G tagged out to maint. to perform MR2-79-5384, 2-79-5670, 2-79-5856, 2-80-406	2	17	35
1-30-80	1930	1-30-80	2230	1B D/G failed to demonstrate Divisional PSW pump interlocks to 1B D/G within 8 hrs		3	

PRELIMINARY

ENCLOSURE 11

NUREG-0737 ITEM II.k.3.21

CORE SPRAY AND LOW PRESSURE COOLANT

INJECTION SYSTEMS LOW LEVEL INITIATION

Attached as part of this enclosure is a generic report titled "Core Spray and Low Pressure Coolant Injection Systems Low Level Initiation" developed by General Electric Company for BWR Owners Group. This report is presently under review by Georgia Power Company. It should be noted that Plant Hatch LPCI pumps have an orifice on their discharge which prevents pump run-out thus removing the concern expressed in paragraph 2, page 14.

No modifications are planned pending completion of our review of the generic position.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 ITEM II.K.3.21

CORE SPRAY AND LOW PRESSURE COOLANT
INJECTION SYSTEMS LOW LEVEL INITIATION

CONTENTS

NUREG-0737 ITEM II.K.3.21

CORE SPRAY AND LOW PRESSURE COOLANT INJECTION SYSTEMS LEVEL INITIATION

SUMMARY

The NRC has suggested certain modifications to the BWR Core Spray (CS) and Low Pressure Coolant Injection (LPCI) systems provided as part of the BWR ECCS network. These NRC suggestions center on control system logic modifications that would provide greater automatic system restart capability following manual termination of system operation. General Electric and the BWR Owners' Group have reviewed this issue on a generic basis and do not believe the NRC suggestions are required for plant safety considerations. This conclusion is based on the adequacy of the current ECCS logic design coupled with the potentially negative impact on overall safety of the proposed changes. For the low pressure ECCS these negative impacts include a significant escalation of control system complexity and restricted operator flexibility when dealing with anticipated events. Therefore, we conclude that no modifications be made to the low pressure ECCS with respect to automatic restart.

GE and the BWR Owners' Group have evaluated a modification to the HPCS system which would automate its restart on low level following its trip by the operator. This change would make the HPCS restart logic similar to the HPCI logic which already permits an auto restart on low level. We have concluded that this change, although not required for safety reasons, would lead to a net safety improvement which could be implemented without adverse impact on system performance.

This memorandum provides an overview discussion of GE's BWR ECCS design philosophy and presents the technical rationale for the GE/Owners' Group position on this issue.

1. INTRODUCTION

This memorandum has been prepared in response to Item II K.3.21 of NUREG-0737. In this Item, the NRC suggested certain modifications to the Core Spray (CS) and the Low Pressure Coolant Injection (LPCI) Emergency Core Cooling Systems (ECCS) that are provided as part of the BWR ECCS network. The NRC suggestions center on incorporating additional control system logic to provide automatic system restart from a low reactor water level signal following actions by the operators to terminate system operation. The NRC concern is that the reactor operators may terminate ECCS operation when a high reactor water level condition exists but may neglect to reinitiate the systems if a low level condition recurs.

General Electric and the BWR Owners' Group have reviewed the current CS and LPCI system for the plants identified in Appendix C and have concluded that overall BWR safety would not be enhanced by the type of control system modification suggested by the NRC. This memorandum describes the current CS and LPCI logic design and provides the technical rationale for the GE/Owners' Group position. This discussion is generic and includes the LPCI and both the low and high pressure core spray systems (LPCS/HPCS). There are some plant to plant variations in these systems but these variations are not important to the overall technical conclusions presented in this memorandum. Neither the High Pressure Coolant Injection system (HPCI) provided on some pre-BWR/5 reactors nor the Reactor Core Isolation Cooling (RCIC) system is discussed.

Section 2 of the memorandum describes the major elements of the GE ECCS design philosophy that are relevant to any discussion of providing expanded system automatic restart capablity. A full understanding of the significance of CS and LPCI logic changes must be based on a recognition that these systems are part of the interdependent BWR ECCS network; any changes in one system must consider the possible interactive effects amongst the other systems making up the overall ECCS network. This must also include the potential impact on supporting systems such as the standby power supplies and the emergency service water system.

Furthermore, the LPCI system is a sub-system of the Residual Heat Removal (RHR) system which has other safety related functions such as suppression pool (containment) cooling and containment spray. Clearly, these other safety functions must not be compromised by any changes in the LPCI mode of operation.

Section 3.1 describes the sequence of events that would occur during several key reactor system transients. This information is for typical BWR transients and identifies system actions which occur automatically and also what operator actions are required. The intent of these generic event descriptions is to illustrate the adequacy of the current BWR ECCS design and to support the position that no modifications are required on the basis of any safety considerations.

Section 3.2 identifies the points in the transient events where inappropriate operator intervention and errors have the potential for leading to inadequate core cooling. These conditions are reviewed and it is concluded that in no case does the probability for error warrant any ECCS control logic change.

Furthermore, the safety margins incorporated in the BWR design provide considerable time between the point at which the operator should (but does not) take action and the time at which core cooling would be jeopardized. Typical BWR data is provided in Appendix B.

An important point of design philosophy is involved in the discussions presented in this memorandum. Control of BWR safety systems will always involve a combination of automatic and manual actions; the issue raised by this NUREG-0737 Item is simply where and how to define the boundary between these two control methods. The current GE ECCS designs are based on the approach that automatic system initiation is required during the short term phase of any incident but that longer term system control can and should depend upon the manual actions of the plant operating staff. Intuitively, it might appear that additional ECCS automation would be purely beneficial since this would supposedly provide added protection against operator errors and omissions. However, these perceived benefits of extended system automation must be measured against the very real penalties of increased system complexity, reduced system reliability and restricted operator flexibility for dealing with unanticipated events. These considerations are not amenable to precise quantification and control system design decisions must of necessity involve judgements as to relative importance of these competing influences. GE and the BWR Owners' Group believes the current BWR low pressure ECCS logic design has considered all of these factors and represents a balanced solution.

GE and the BWR Owners' believe that the current BWR 5/6 High Pressure Core Spray (HPCS) system is fully adequate and no design changes are required on a basis of any safety considerations. However, there are relatively straightforward HPCS design modifications that would automate the restart of HPCS on low level following its trip by the operator similar to the HPCI logic. This change which would enhance overall plant safety is described in Appendix A of this memorandum.

2. GENERAL ELECTRIC ECCS DESIGN PHILOSOPHY

This section provides an overview discussion of the generic GE ECCS design philosophy and design practices as they govern ECCS initiation and operator control of these systems. ECCS control systems must satisfy multiple system design requirements and the information presented in this Section and Section 3 is intended to demonstrate that the current ECCS controls are based on a balanced consideration of these multiple requirements.

2.1 LOCA Signals

High drywell pressure* and low reactor water level** are the key accident related parameters that govern operation of the BWR ECC systems. The occurrence of either or both of these signals is taken as an indication that a Loss of Coolant Accident (LOCA) has occurred. This combination provides diversity of initiating signals but it is important to note that the control system hardware does not discriminate between signals generated by the drywell pressure sensors and those produced by the reactor water level instruments. Either or both of these sensed variables can produce a LOCA signal input to the control circuitry.*** The latter does not treat the signals separately and there is currently no way for the control hardware to recognize which parameter is indicating a LOCA condition exists.

This is a significant design feature because it means system logic reset cannot be accomplished until both of these LOCA signals have cleared: and an ECC system cannot be returned to its true standby mode until the logic circuits have been reset. With the current design, automatic restart of any ECC system will occur once it has been placed in the standby condition and an initiation signal recurs. As discussed below, there are in practice many BWR accident sequences where one or both of the ECCS initiation signals will persist for long periods of time. This characteristic complicates any scheme to provide the type of system restart proposed by the NRC.

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* Typically 2 psig.

** Actual setpoints are plant and system dependent. All setpoints are above the top of the active core.

*** Common LOCA logic is developed within each redundant ECCS division, so the core spray and LPCS controls receive the same signal at the same time.

The long term post-LOCA transient is good example of the significance of the combined drywell pressure and reactor water level LOCA signal input to the BWR ECCS. For all but the largest breaks, reflooding of the core will occur relatively soon after the ECCS have been automatically started by the high drywell pressure and/or low reactor water level signals. However, the high drywell pressure condition may persist for extended periods following the accident and the continued presence of this LOCA signal will prevent ECCS logic reset and thus prevent return of these systems to their standby mode. Control system modifications to provide automatic restart on low reactor water level would have to be based on logic that recognizes the possibility of a continuously present drywell pressure signal. The possibility for the drywell pressure signal not being present would also have to be included in the logic; longer term post-LOCA containment pressure conditions are sensitive to factors as break size, break location, type of ECCS equipment operating, etc. and pressures both above and below the 2 psig value could occur depending upon plant conditions.

In summary, the diversity of initiation signals is an important design philosophy that has had a major influence on the current BWR ECCS control system design. However, the BWR LOCA performance is such that one or more ECCS initiation signals can persist for extended periods of time. Any scheme to provide ECCS automatic restart capabilities would have to be complex in order to deal with this possibility. The added safety benefits of an automatic restart design must be balanced against the decreased reliability of the system brought about by the additional control system complexities required to implement the change.

Sections 2.3, 2.6 and 2.7 provide further discussion of this point.

2.2 Automatic System Initiation

Immediately following a LOCA that produces either high drywell pressure or low reactor water level, all BWR ECCS will automatically start. Injection of emergency cooling water into the reactor will occur when reactor pressure is within the design range of each particular system. This design feature would not be influenced by any plant modification to provide ECCS automatic restart capability.

Annunciators are set off by the initiating condition and are subsequently acknowledged by the plant operators. The audible alarm is silenced by the operator after he has acknowledged the conditions and determined his required action but the panel light persists until the originating condition disappears. Reoccurrence of the originating condition would cause a new audible alarm and alert the plant operators to the need to reactivate any secured pumps and restore reactor water level. These important control room annunciation/alarm features of the typical BWR together with the BWR reactor water level indicators will provide information that will ensure that the control room staff is continuously aware of the reactor water level condition and will undertake all the necessary safety actions in a timely manner.

2.3 Automatic System Termination

The low pressure emergency systems do not stop automatically in the event either the drywell pressure or the reactor water level signals return to non-LOCA conditions. See Paragraph 2.4 for high water level trip of the HPCS system.

In some plants, high-high containment system pressures will cause a portion of the LPCI system to automatically realign to the containment spray or wetwell spray mode of operation. (Some time delay is provided to allow reactor water level recovery). This design feature is intended to enhance the ability of the pressure suppression containment system to accomodate steam bypass of the drywell/wetwell vent system. Reoccurrance of the LPCI autostart signal would create conflicting simultaneous automatic signals which would have to be resolved by a priority logic and its attendant complications.

2.4 System Termination on High Level

In general, flow from the High Pressure Core Spray (HPCS) system is terminated when a high reactor water level condition occurs (typically referred to as Level 8). The intent of this control feature is to prevent unnecessary flooding of the reactor vessel and steamlines. Termination of HPCS injection can occur either automatically or by operator action. In the event of the former, the HPCS system will restart automatically if and when reactor water level decreases from the high level trip point to the low level initiation setpoint.

Depending upon the circumstances involved, automatic restart may or may not occur following operator termination of the HPCS system. (See Secion 2.5 for additional discussion.) It should be noted that the Reactor Core Isolation Cooling (RCIC) system is also available for high pressure reactor water makeup duty and can be considered a diverse backup for the HPCS. (See Note 1)

2.5 Operator Termination

The reactor operators can, at any time, stop any BWR ECCS system even if a LOCA signal is present. This manual override option is deliberate and is considered by General Electric to be an important safety feature of the BWR ECCS network. This feature provides the plant operators with flexibility for dealing with unforseen but credible conditions requiring a particular system to be shut down. Examples would be equipment difficulties involving gross seal leakage, breaks in ECCS piping, failed ECCS pump motors, load shedding for other post-LOCA operations etc. General Electric strongly believes that any design changes which restrict this operator flexibility would not be beneficial and would not lead to improved plant safety. Because the reactor water level is directly measured in the BWR and the water level is a primary parameter in the operator guidelines, operator action is a highly reliable means of reinitiating low pressure ECCS if needed to assure adequate core cooling. It is believed the overall system reliability is higher if flexibility is included for operator action as compared to a system which cannot be overridden if a LOCA signal is present.

(NOTE 1: The BWR/6 HPCS control logic currently includes a high drywell pressure override of the high level flow termination signal, i.e., if a high drywell pressure signal is present, the HPCS system will not terminate on high level and will flood the reactor and main steamlines. General Electric believes overall plant safety would be improved if this override feature were removed and is currently reviewing such a change with the NRC staff.)

Depending upon the reactor condition, operator termination of a BWR ECCS can be achieved in several ways. Figure 1 is a schematic diagram which illustrates these options for typical low pressure systems. The schematic in Figure 2 illustrates the logic for the BWR/5 HPCS system. The key points to note are:

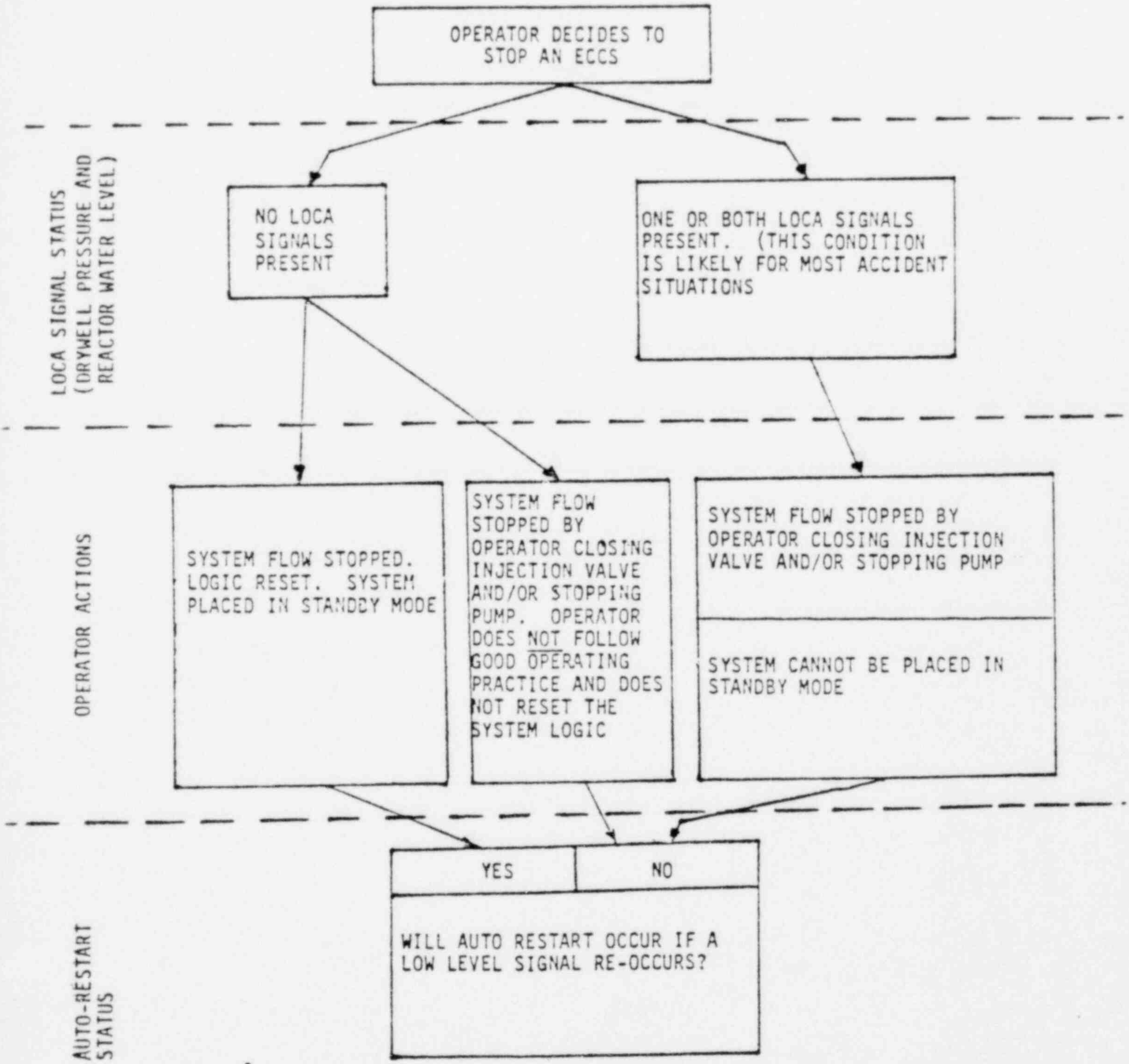
1. If properly secured and returned to the standby mode, all ECCS will automatically reinitiate if a LOCA signal re-occurs. Standby status can be acheived when all previous LOCA signals have cleared and the sytem logic has been reset. Correct operating procedure would be for the operator to attempt to return all ECCS to their standby mode any time a system is being secured; only when conditions such as the continued presence of a LOCA signal prevent this operation would a system be stopped and left in a non-standby mode.

2. If a LOCA signal persists, system flow can be terminated but the system cannot be returned to standby status. A typical ECCS system logic permits the operator to override the incoming automatic start logic (from the persistent LOCA signal) by use of either the "stop" position of the pump manual switch or the "close" position of the system injection valve. Momentary contact of either switch actuates logic elements which block the incoming automatic initiation signal. Once blocked, the automatic signal no longer controls pump or valve action and any subsequent system operation will be dependent upon manual operator actions.

3. An improperly secured system (eg: an injection valve closed but system not returned to standby mode) will not automatically restart if a LOCA signal reoccurs.

OPERATOR TERMINATION OF BWR
EMERGENCY CORE COOLING SYSTEMS:

A SCHEMATIC SHOWING TYPICAL OPTIONS



*OPERATOR RESPONDING TO EITHER A MALFUNCTIONING SYSTEM OR A NEED TO INITIATE OTHER SAFETY RELATED FUNCTIONS (EG: ESTABLISH SUPPRESSION POOL COOLING)

FIGURE 1

OPERATOR TERMINATION OF BWR ECCS

A SCHEMATIC SHOWING BWR/5 HPCS TERMINATION ON HIGH REACTOR WATER LEVEL

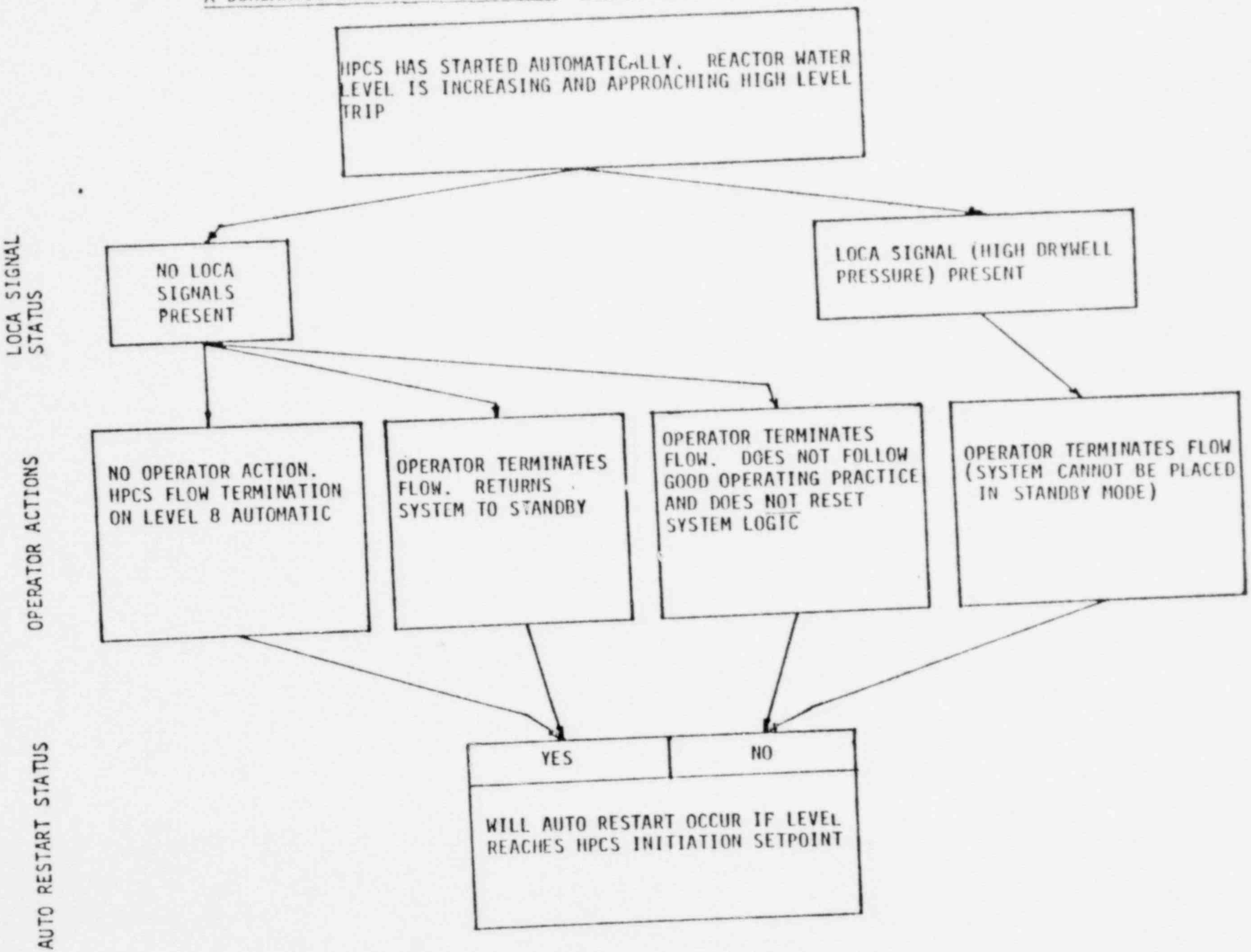


FIGURE 2

2.6 Long Term Control

BWR emergency system design is based on the assumption that long term control of the reactor will be completely dependent upon operator actions. This long standing design philosophy has been consistently applied to reactor control following both non-LOCA transient events (such as turbine trip) and also to the complete spectrum of credible loss of coolant accidents. A good example of this philosophy is the complete manual control of the multiple operations required to establish the long term post-LOCA containment cooling functions. Post-LOCA containment cooling is a key safety function since it prevents containment overpressurization and is thus required to support long term cooling of the core.

Providing purely manual control of the long term BWR transients is based on the thesis that the operator will ensure continued core cooling. This manual approach is considered superior to providing the very complex equipment and controls that would be necessary for comprehensive automatic ECCS restart capabilities during these transients.

As an indication of the potential complexity of the control systems that would be required, the following are some of the major long-term transient considerations that would have to be accounted for.

1. In many cases, the station standby power sources do not have sufficient capacity to permit all emergency systems to run simultaneously. The plant operators must establish priorities and make the necessary power assignment decisions. An example of this process would be the decision to shut down one or more of the multiple ECCS in order to provide power to the emergency service water pumps. This is clearly an appropriate action for the operators to take since the multiple ECCS will be providing redundant core cooling and the essential service water system must be activated if the containment cooling and pressure control functions are to be established.

Any scheme to automatically restart the ECCS in a vessel injection mode would have to recognize and account for these other essential post-LOCA activities as well as recognize unavailable or failed systems and equipment.

2. For many plants, operator action is required to ensure adequate ECCS pump Net Positive Suction Head (NPSH) during events involving elevated suppression pool temperatures. In most cases, automatic ECCS system initiation does not involve any system flow control. Consequently the system will operate at the maximum flow rate as vessel pressure reaches drywell pressure. This operating mode is usually referred to as the run out condition and it involves the most severe NPSH requirement at the pump suction. NPSH conditions can (in some cases) lead to pump cavitation as the suppression pool water temperature increases. These undesirable NPSH situations are avoided by the plant operator manually adjusting the system flow rate to design values. Again, this aspect of design would have to be accounted for in any scheme to provide auto-reinitiation capability.

3. Many BWR transient and accident events involve significant release of reactor system energy to the suppression pool which increases the pool temperature and containment pressure. Control of these temperature/pressure conditions is achieved by manually placing the LPCI/RHR system in the suppression pool cooling mode. This LPCI/RHR mode, in conjunction with emergency service water system operation, permits rejection of the excess suppression pool energy to the station ultimate heat sink. Much of the equipment used for this cooling function is also used for the LPCI ECCS mode of the RHR system. Any scheme to provide automatic initiation of the ECCS system would either have to bypass the LPCI system after it has been assigned to the suppression pool cooling function or automatically realign the equipment to the LPCI mode.

Consideration of the second option provides a good example of the many practical difficulties associated with rectroactive modification of BWR ECCS systems. Automatic realignment of the RHR system from the suppression pool cooling mode to the LPCI mode would have to recognize the "as-built" characteristics of the hardware involved. For example, the typical RHR pool return line valve is a 12 - 18 inch valve which would require 90 seconds to close whereas the LPCI injection line is a 12 - 24 inch valve which would open in 24 seconds. This represents a 3:1 valve closure period mis-match and any simultaneous signal to realign the RHR system would result in a significant period of time during which the RHR pump would be supplying flow to both flow paths. The RHR pumps are not designed for the excess duty associated with this mode of operation: inadequate pump NPSH, pump motor overloading and auxiliary power source overloading are potential problems that would have to be addressed. Clearly, these types of hardware problems are not insurmountable but would have to be addressed as part of any rectroactive ECCS modifiction program.* The intent of this discussion of potential difficulties is not to suggest that rectroactive ECCS system logic changes are impossible but rather to highlight the non-trival hardware changes that may accompany any control system logic redefinitions.

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* Additional logic to avoid the valve timing mismatch requires additional LPCI valve permissives and so adds to the probability of failure.

2.7 BWR Geometry Considerations That Impact System Logic

The BWR core and internals configuration are such that certain design basis break locations and sizes do not permit complete post-LOCA reflooding of the core. For jet pump plants, very large ruptures in the external recirculation system pipe allow the ECCS to reflood the reactor vessel only to the elevation of the jet pump suction plane. This elevation is at approximately 2/3 of the core height. However, the actual water level inside the shroud is considerably higher due to the existence of voids. For non-jet pump plants large recirculation line breaks do not permit full reflooding of the core. Adequate core cooling is achieved under these conditions for either reactor type but the reactor water level can never be restored to the ECCS initiation level.

This characteristic complicates any scheme to provide automatic reinitiation of the ECC systems on low water level. For large breaks in jet pump plants, inadequate core cooling would probably have to be defined so as to be based on the 2/3 core height level. This revised definition would have to be in addition to the current initiation level which is conservatively identified as a water elevation <u>above</u> the core. It is not clear what comparable alternative signal could be used in the case in the non-jet pump plants. However, it is believed that the minimal need for (and benefits of) providing automatic ECCS reinitiation for large BWR recirculation line breaks does not justify the penalties associated with the significantly more complicated control system that would be required. In summary, the current ECCS logic is well suited to the BWR geometry characterisitcs and no changes are required on the basis of the inadequacies in the current design.

3. TYPICAL EVENTS INVOLVING ECCS INITIATION

3.1 Event Description

Typically analyzed BWR LOCA and non-LOCA events are discussed in this Section of the memorandum; the events have been treated generically. In each case the emphasis is based on interactions between the LOCA signal and the actions the plant operator can or must take to ensure safe plant conditions. The event descriptions are based on current ECCS control system logic.

The following events have been selected as representative BWR transients:

1. A design basis recirculation line break which will not permit reflooding of the core above the 2/3 core elevation. This accident is included as a base case to illustrate the reasons for the existing system logic.

2. A small break not involving significant loss of reactor water inventory. This accident will lead to high drywell pressure but not a low reactor water level ECCS initiation signal.

3. An intermediate size loss of coolant accident that involves some core uncovery but with a subsequent reflooding of the reactor by the ECCS.

4. An upset transient that produces a momentary reactor water reduction and thus HPCS initiation on low water level but no high drywell pressure LOCA signal.

Tables 1 through 4 show the major sequence of events for these four transients.

TABLE 1

TYPICAL BWR TRANSIENTS

CASE 1: DESIGN BASIS RECIRCULATION LINE BREAK

SEQUENCE OF EVENTS

- Break occurs
- High drywell pressure signal — These signals will persist
- Low reactor water level signal — indefinitely and cannot be reset.
- All ECCS start and inject water into the vessel automatically
- Core heat-up terminated, all ECCS running, core flooded to 2/3 height. In some cases, part of the LPCI flow may automatically be diverted to containment or wetwell spray.

END OF SHORT TERM BLOWDOWN PHASE OF ACCIDENT

Core cooling dependent upon operator actions

- Multiple operator actions to establish long term post-LOCA core and containment cooling. Actions include some ECCS termination, standby power reassignments, emergency service water startup, actuation of suppression pool cooling, pump throttling to assure adequate NPSH, elimination of unnecessary ECCS pump operation so as to minimize pump heat input to the suppression pool etc.

TABLE 2

TYPICAL BWR TRANSIENTS

CASE 2: SMALL BREAK NOT INVOLVING SIGNIFICANT LOSS OF REACTOR INVENTORY (BWR 5/6)

SEQUENCE OF EVENTS

- Break occurs

- High drywell pressure signal - signal will persist indefinitely

- No low reactor water level

- All ECCS start automatically (low pressure systems will not inject because of high reactor pressure)

- HPCS Injection

OPTION 1	OPTION 2
- HPCS flow terminates automatically on high level (Level 8) (assuming deletion of high drywell pressure inhibit for BWR/6)	- Operator observes increasing reactor water level and terminates HPCS by stopping pump or closing injection valve. This action precludes subsequent automatic initiation on low level
- HPCS auto restarts on initial level (Level 2)	- Subsequent HPCS restart requires operator action. Because of persistent high drywell pressure, system logic cannot be reset and system returned to standby
- Continuous automatic reactor water level control	

END OF SHORT TERM PHASE OF EVENT

Core cooling dependent upon operator actions	- Multiple operator actions to inititate orderly shutdown of reactor. Depending upon equipment availability, heat rejection will be to main condenser, suppression pool, or normal shutdown path. Considerations will be to establish core and containment cooling, assure adequate power supply distribution, start emergency service water pumps, throttle pumps to assure adequate NPSH, etc.

TABLE 3

TYPICAL BWR TRANSIENTS

CASE 3: INTERMEDIATE LOSS OF COOLANT ACCIDENT

SEQUENCE OF EVENTS

- Break occurs
- High drywell pressure signal. (This signal will persist indefinitely)
- Low reactor water level signal. (Level will be recovered at some point in the accident)
- All ECC systems start automatically
- Core uncovery/heatup transient terminated. All ECCS running, reactor vessel flooded. In some cases, part of the LPCI flow may be automatically diverted to containment spray.

END OF SHORT TERM PHASE OF ACCIDENT

Core cooling dependent upon operator actions

- Multiple operator actions essentially same as those identified in Table 1 for the Design Basis Accident (DBA)

TABLE 4

TYPICAL BWR TRANSIENTS

CASE 4: UPSET TRANSIENT (BWR 5/6)

SEQUENCE OF EVENTS

- Upset event
- Low reactor water level signal occurs (either due to loss of feedwater or because of momentary level reduction due to void collapse). High drywell pressure does not occur.
- High pressure system starts and injects
- Reactor water level increasing

OPTION 1	OPTION 2
- HPCS flow terminates automatically on high level	- HPCS flow terminated by operator. Logic cleared, system returned to standby mode
- HPCS auto restarts when initiation level reached	- HPCS auto restart if initiation level reached
- Continuous automatic reactor level control	- Repeat of cycle. Continuous automatic reactor level control

END OF SHORT TERM PHASE OF EVENT

- Multiple operator actions essentially the same as those identified in Table 2

3.2 Assessment

The thrust of the NRC position as stated in the NUREG-0737 Item can be summarized as follows:

> Is it possible that the plant operators could stop an ECC system at a time and in a manner that would, unless the system is manually restarted, lead to inadequate core cooling? If this is the case, and since there is a remote chance the operator may not restart the system, restart should be made automatic.

The simple response to this position is that the current BWR ECCS design does indeed permit the plant operators to terminate system operation in a way that would eventually jeopardize cooling of the core assuming the operator ignors the water level instrumentation and procedures. However, a review of the particular circumstances that would have to be involved leads to the conclusion that this is not necessarily an unacceptable situation which must be immediately remedied by providing additional ECCS automation. To support this position, the typical generic events described in Table 1 through 4 have been subjected to the following questions.

- What operator actions are required?
- What deleterious operator actions are possible?
- Could the deleterious operator actions lead to degraded core cooling?
- Is an ECCS logic design change required to protect against the possible operator errors?

Table 5 summarizes the response to these questions for the four typical generic BWR transients described in Section 3.1.

A review of Table 5 shows that the current ECCS control logic coupled with reasonabale operator actions provides adequate core cooling throughout the four typical events presented. However, there are three general circumstances where it is possible (but not probable) for operator errors to produce conditions that could potentially lead to degraded core cooling. These conditions are:

1. Deliberate operator termination of multiple ECCS during the earlier phases of an incident when the sytems have been automatically initiated. In general, automatic restart will not occur because the initiating signals (high drywell pressure and low water level) will still be present and will preclude the system logic reset. The ECCS logic design which permits operator intervention is based on a legitimate assumption that the operators are not likely to prematurely terminate ECCS flow and jeopardize the core cooling process. In actual practice, one of their highest priority activities will be to assess the situation to assure all emergency systems have started correctly and attempt to start any that may not have. The alternative to providing this operator flexibility would be to design the system so that any termination attempt by the operators would be overridden. This is not considered good design practice since it provides no flexibility for the operator to deal with unanticipated situations in which overall plant safety may be increased if a malfunctioning ECCS system can be shut down. An example of the latter would be to secure a system that has gross seal leakage that could potentially flood an ECCS compartment and deplete pool water.

2. A second general circumstance during which errors and omissions could potentially lead to degraded core cooling conditions would be a failure of the operators to adequately consider core cooling requirements during the long term period. During this longer term phase, the plant operators are manually setting up the auxiliary systems to support eventual termination of the incident. In the event of degraded core cooling, automatic ECCS initiation is unlikely to occur because the systems will not be in a true standby mode. Consequently, adequate core cooling is dependent upon correct operator actions.

Again, this aspect of ECCS design is considered fully acceptable because of the time available between attaining level one and the occurrence of high fuel clad temperatures. (See Appendix B) The operator must take manual control of all systems during this period and it is not considered credible that he would provide inadequate cooling to the core. As discussed in Table 5, the alternative would be to provide the complex logic necessary to automaticaly restart certain ECCS. This would involve a major escalation of control system logic complexity and the benefits of added protection against unlikely operator error do not appear to compare favorably with the penalties of increased control system complexity, decreased system reliability and the loss of operator flexibility in dealing with unanticipated events.

3. During upset transients and small breaks, the highest reactor operator priority with respect to control of water level will be to avoid overfilling the vessel and flooding the main steam lines. These events will initiate the HPCS and the control logic is capable of automatically maintaining the reactor water level within the HPCS level control range (i.e. between the high level trip elevation and the low level system initiation setpoint). However, it is highly desirable for the plant operators to intervene in this automatic process and assume manual reactor water level control. The key incentive is to prevent the water level from reaching Level 8 since in addition to the HPCS, both the feedwater system (if operating) and the RCIC will be tripped on high level. Consequently, it is probable that for the types of events described in Tables 2 and 4, the plant operators will intervene fairly early and assume manual HPCS control. Under normal circumstances, good operating practice will result in the system being returned to a standby condition anytime system operation is terminated. Automatic restart on low reactor water level will then occur.

If a persistent LOCA signal is present, it will not be possible to return the HPCS to a standby mode and continuous manual control will be required. Inadequate core cooling as a result of the operator failing to reinitiate the HPCS system would not occur because eventually the ADS initiation level would be reached. This would result in reactor blowdown and core flooding by the low pressure ECCS. However, the availability of level data coupled with operator training that has stressed the central importance of adequate water level will ensure appropriate and timely operator control of the HPCS during transients and small break accidents.

This conclusion is further reinforced when it is remembered that during a transient event, at least one half hour of <u>zero</u> reactor makeup flow conditions can be permitted to exist before clad temperatures approaching 2200 F will occur. (See Appendix B)

NOTE: The High Pressure Core Spray (HPCS) system currently restarts automatically if the Level 2 initiation signal reoccurs and the system is in the fully automatic mode or the system had previously been returned to standby conditions. Our evaluation of Item II.K.3.21 has considered the potential benefits of modifying the HPCS logic to extend automatic restart on Level 2 following manual termination. (See 2.4 and 2.5) This logic is already included in the HPCI system design. It has been concluded that such HPCS changes are not required by plant safety considerations. However, the changes that would provide this capability appear to be relatively straightforward and may provide additional safety margin. The recommended changes are described in Appendix A.

EVENT	CONDITION	REQUIRED OPERATOR ACTIONS	POSSIBLE DELETERIOUS OPERATORS ACTIONS (A)	COULD (A) LEAD TO DEGRADED CORE COOLING	IS A DESIGN CHANGE REQUIRED TO PROTECT AGAINST (A)	COMMENTS
1, DBA	Short term blowdown phase of accident	None	Operator could conceivably intervene and terminate flow. Sytems would not automatically restart. (Logic cannot be cleared because initation signals are present)	Yes, if sufficient systems were stopped	No. Water level maintenance is emphasized during operator training and reinforced by the Emergency Procedure Guidelines	Operator would have multiple indications that a loss of coolant accident had occurred. It is not credible that he would stop sufficient ECCS to cause degraded core cooling. Preventing manual override is not good design practice. See Section 2.5
1, DBA	Long term post-LOCA core and containment cooling	Multiple actions required. See Table 1	Core cooling could be interrupted by operator actions which violate guidelines and procedures. Automatic system restart would not occur because high drywell and low water level signals are continuously present and preclude logic reset	Yes, if sufficient systems are stopped	No. It is reasonable to assume the operator will follow procedures and accomplish all long term core and containment cooling functions satisfactorily. Extended time periods are available. Water level does not recover above 2/3 core height; however up to 20 minutes is available before zero ECCS flow would cause excessive fuel heat-up. See Appendix B	Redesign of the ECCS control logic to provide automatic restart of the certain ECCS would require a major complication of control system logic. This expanded logic would have to recognize and account for the multiple considerations identified in Table 1 and Section 2.6. (The pool cooling function, limited standby power sources, pump NPSH, service water requirements etc). The benefits of added protection against operator error do not balance the penalities of increased control system complexity (and thus failure rate) and loss of operator flexibility in dealing with unanticipated events
2, Small Break	HPCS has started automatically and is injecting into the reactor vessel	None, other then to monitor the situation especially reactor water level. System will automatically terminate flow on high level and restart at low level initiation value	Premature termination of HPCS flow. System cannot be returned to standby mode because LOCA signal present and will not permit logic reset	No, remainder of ECCS network would automatically provide cooling. It is probable the operator would manually re-initiate HPCS flow. RCIC is a backup	No. Low water level is annunicated and alarmed in the control room; there is a considerable period of time before zero makeup flow would cause fuel heat-up; operator training and the Emergency Procedure Guidelines emphasize level control	Probability of operator terminating HPCS flow and allowing the vessel level to reach the ADS setpoint in very low. Even if this occurs, core cooling is never jeopardized
2, Small Break	Same as above	Same as above	As above but further compounded by operator securing the low pressure systems. None of the systems can be returned to the full standby mode and would not restart automatically	Yes, but not considered a credible situation. Operator would continue operator water level with HPCS and RCIC	No. (See above)	Probability of this series of multiple operator errors is less than above

TABLE 5

EVENT	CONDITION	REQUIRED OPERATOR ACTIONS	POSSIBLE DELETERIOUS OPERATORS ACTIONS (A)	COULD (A) LEAD TO DEGRADED CORE COOLING	IS A DESIGN CHANGE REQUIRED TO PROJECT AGAINST (A)	COMMNETS
2. Small Break	Long term actions to initiate orderly shut-down to cold conditions	Multiple actions required. See Table 2	Core cooling could be interrupted by operator actions which violate guidelines and procedures. Automatic system restart would not occur because the continuously present high drywell pressure prevents logic reset	Yes, if sufficient operator error are made	No. It is reasonable to assume the operator will follow procedures and accomplish all long term core and containment cooling functions satisfactorily. Extended time periods are available. (See Appendix B)	See comments on Event 1, BDA, long term post-LOCA transient
3. Intermediate Break	Short term blowdown phase of the accident	Same discussion and conclusions as for the DBA. No design changes required.				
3. Intermediate Break	Long term post accident core and containment cooling					
4. Upset Transient	Short term responses. Reactor water level rising	None other than to monitor the situation especially water level. HPCS is capable of automatic stopping and starting within its level control range	HPCS system flow terminated and system returned to standby mode. (Requires no initiation signal present	No, system will automatically restart on low level	No	If the plant operator takes no action or if he correctly terminates HPCS flow, the system will respond automatically to low reactor water signal
4. Upset Transient	Short term response. Reactor water level rising	As above	HPCS system flow terminated by simple pump stoppage or injection valve closure. System not returned to standby mode	Adequate core cooling will eventually require operator action. HPCS will not auto restart and ADS initiation will require manual action	No. An unlikely operator error is involved. Also, RCIC system would be available as a backup. See comment on Item 2. Extended time periods available. See Appendix B	
4. Upset Transient	Long term post incident recovery	Same comments and conclusions as other long term transients i.e. adequate core cooling dependent upon operator action. Situation acceptable				

4. CONCLUSIONS

The current BWR ECCS control logic as well as the CS and LPCI logic modifications suggested by the NRC in NUREG-0737 Item II.K.3.21 have been reviewed. This review has included a consideration of all aspects of HPCS, LPCS and LPCI system operation which would be influenced by any expanded automatic restart capability. It is concluded that the current system design is adequate and no design changes are required. This conclusion is based on a combination of factors that include: the comprehensive nature of BWR operator training, the emphasis placed in this training on reactor water level control, the Emergency Procedure Guidelines, the relatively long time the operator has to correct errors and the extent to which low reactor water level conditions are displayed and alarmed in the control room. The most important consideration is that the benefits of providing enhanced automatic ECCS reinitiation do not justify the associated penalties of increased system complexity, reduced system reliability, restricted operator flexibility and the other undesirable effects discussed in this memorandum.

In summary, General Electric and the BWR Owners' Group believe the current BWR low pressure ECCS design, when coupled with rigorous and continuous operating staff training programs, represents the optimum approach to BWR safety. No modification of existing LPCI and low pressure core spray system need to be undertaken. Modification of the HPCS system to automate restart on low level following manual trip, although not required for safety considerations, will lead to a net improvement in overall ECCS performance.

APPENDIX A

High Pressure Core Spray (HPCS) System Modifications

GE and the BWR Owners' Group have reviewed the current HPCS system and have concluded that no system design changes are required. However, some additional safety margin may be added to the BWR design by making a relatively straightforward modification to the HPCS control logic to provide automatic restart of the system following manual termination of pump operation. The purpose of this Appendix is to conceptually describe this potential HPCS design change.

Summary

Auto restart of HPCS after manual stop can be provided if a logic system can be developed which:

(1) Restarts the HPCS pump on Level 2,
(2) Blocks high drywell pressure restart,
(3) Self clears if both auto signals disappear, and
(4) Still allows injection valve closure or pump stop if absolutely essential for protection of the public.

Any such design should adhere to the applicable portions of IEEE 279-1971.

Existing Logic Design

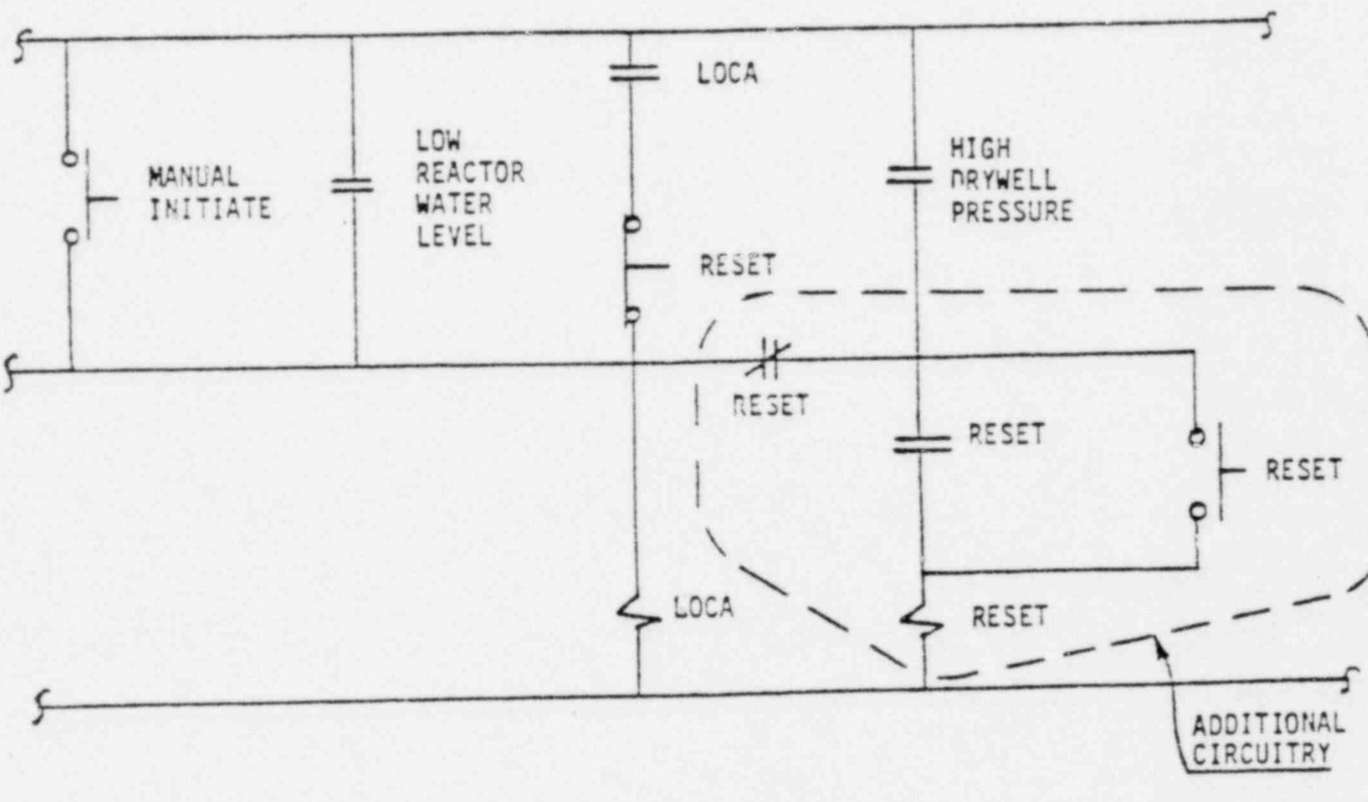
The HPCS system is initiated by either high drywell pressure or low (Level 2) reactor water level. Each parameter has four sensors and analogic trip units or four switches set up in a one-out-of-two-twice logic scheme. The above logic is assembled and the output fed to an OR gate along with the system level manual initiation signal. The output of the OR gate is a LOCA initiation signal which is sealed in. A reset switch permits release of the seal in. The assembled initiation signals are not sealed in so that they self-clear when the abnormal condition disappears.

Proposed Modification

The feature being considered will reset the auto initiation signal, on level and block the continuing auto initiation signal based on high drywell pressure. This will allow auto HPCS restart on low level after operator stop of the pump. It does block auto restart on high drywell pressure unless drywell pressure decreases below the setpoint and again increases above the setpoint. A decrease in drywell pressure below trip level will remove all reset features and return HPCS logic to the original status. The HPCS pump is not stopped automatically by any reset. Pump stop still requires operator action.

System isolation must still be possible with or without this modifiction.

HPCS INITIATE CIRCUITS



CONCEPTUAL DESIGN

HPCS INITIATION CIRCUIT

USING RELAY LOGIC

(SOLID STATE LOGIC IS EQUALLY ADAPTABLE)

APPENDIX B

As discussed in the body of this memorandum, General Electric and the Owners' Group believe the current ECCS control logic is fully adequate. This position is based on a combination of factors one of which is the period of time available between the time at which the operator should (but does not) start an idle ECCS system and the time at which inadequate core cooling may begin. As discussed below this can be a fairly long time period and the purpose of this Appendix is to demonstrate this safety margin that is built into the BWR.

Assuming that after operator termination of a system, there is no source of reactor water level makeup at all and further assuming the core is initially at saturaiton temperature conditions, the following table summarizes the time between pump flow termination and the occurrence of 2200°F fuel clad temperatures.

Case	Time to Reach 2200°F
1. Isolated - no break	
Boil off from Level I (Typically only a few feet above the top of the core)	30 minutes
2. Isolated - large recirculation system break	
Boil off from top of jet pump	15 to 20 minutes

In Case 1, the reactor water level is initially at the ECCS initiation value (Level I). It is assumed that there is no ECCS flow and the reactor boil-off process results in decreasing reactor water level leading eventually to core uncovery. This case is representative of transients involving no reactor system break. It should be noted that Level 1 is a very low reactor level (one or two feet above the top of the active core) and the allowable period of zero reactor water make up is considerably extended if it is assumed to start with a higher reactor water level condition.

Case 2 is representative of a large recirculation line break in a jet pump plant. For this case, it was assumed that there was no water outside the shroud and that the collapse water level inside the shroud is at the top of the jet pump. The swollen water level is actually somewhat higher.

The heat up times given in this Appendix are minimum estimates of typical BWR values. Times would be longer if the events started with less than maximum expected core decay power and/or if the ECCS flow is terminated later in the transient. Availability of other makeup systems such as the control rod drive flow could significantly extend the time before core heat up would occur.

The above information clearly demonstrates that there is a significant period of time available for the operator to recognize that he has inadvertently permitted the reactor water level to decrease and for him to take the necessary corrective action.

APPENDIX C

Participating Utilities

NUREG-0737 II.K.3.21

This report applies to the following plants, whose Owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 1-3
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Northern States Power	Monticello
Pacific Gas & Electric	Humboldt Bay 3
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	Fitzpatrick
Detroit Edison	Enrico Fermi 2
Long Island Lighting	Shoreham
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

ENCLOSURE 12

NUREG-0737 ITEM II.k.3.22

VERIFICATION OF RCIC SYSTEM SUCTION

SWITCHOVER PROCEDURES

Procedures for the manual switchover of the Reactor Core Isolation Cooling (RCIC) system suction from the condensate storage tank to the suppression pool have been verified to exist in a clear format for operator use.

ENCLOSURE 13

NUREG-0737 ITEM II.K.3.27

COMMON REFERENCE LEVEL

Attached to this enclosure is a generic report titled "Common Water Level Reference" developed by General Electric Company for the BWR Owners Group. It should be noted that Plant Hatch's fuel zone instrument's reference zero is located at the vessel bottom head invert vice the top of the active fuel described on page 4 of the generic report. This difference has no bearing on the conclusions of the generic report.

Presently, no change to the reference zero is planned for Plant Hatch level instrumentation. Consideration is being given to marking the top of the active fuel on present indicators.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 II.K.3.27

COMMON WATER LEVEL REFERENCE

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SUMMARY

NUREG-0737, Item II.K.3.27, "Common Water Level Reference", requires that all reactor pressure vessel water level indicator scales be based on a common reference zero. The intent is to reduce a perceived potential for operator confusion due to the different reference points of the various reactor vessel water level instruments.

General Electric and the BWR Owners' Group have reviewed the reactor water level instruments currently provided in a typical BWR control room, and have concluded that this instrumentation provides the plant operators with reactor water level information that will permit the operators to make timely and correct decisions regarding reactor water control requirements. Individual utilities may adopt certain design changes in response to the NRC's request; this decision would be based on the individual utility's operating practices, operator training, and procedures. However, as discussed herein, identification of a common water level reference is not vital to ensure safe reactor operation and consequently, no modification of the current control room water level instrumentation is required on the basis of plant safety considerations.

INTRODUCTION

This memorandum has been prepared in response to NUREG-0737 Item II.K.3.27, "Common Water Level Reference" for the participating utilities identified in Appendix A. In this item, the NRC identified a concern with the two different reference zeros of the various reactor pressure vessel water level indications. The NRC concern focussed on a potential for operator confusion arising from the two different reference points for the various water level instruments.

General Electric and the BWR Owners' Group have reviewed the BWR water level indication system and believe that no modifications to the current instrumentation are required based on consideration of plant safety. This memorandum provides a detailed description of the typical BWR water level indication system and the reasoning for the two reference zeros of this system.

WATER LEVEL INDICATION

The BWR water level indication system provides the reactor operator and safety systems with information regarding vessel water level. This section summarizes the key features of the indication system. The discussion applies generally to all BWR/3 through 6 units. The number of water level indicators in some of the earlier BWR designs is significantly different from the more recent designs, however, the functional description, assessment of the indication system, and conclusions are applicable to these earlier BWR's.

As described in more detail in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", the BWR water level instrumentation provides multiple level indications displayed on the reactor control console or nearby panels in full view of the operator. These indications include (typically) three narrow range (normal operating range) level indicators and one narrow range level recorder, two wide range level recorders and one wide range level indicator, one fuel zone level indicator and one fuel zone level recorder, one upset range level recorder and one shutdown range (vessel flooding) level indicator. In addition, multiple indicating trip units provide wide range and narrow range reactor level safety related trip signals and related alarms. Safety, control, and information functions provided by the level instruments include scram, containment isolation, ECCS initiation, RCIC initiation, permissive signals for ADS initiation, feedwater control, recirculation pump shutoff, MSIV closure, level readout, level recording and level alarm functions in the control room for normal, transient and post-accident conditions.

Figure 1 depicts the correspondence of reactor vessel level and level indicator and recorder ranges. As can be seen in the figure, reactor water level indication covers the vessel in overlapping ranges from below the bottom of the active fuel to the top of the vessel.

There are several water levels of major importance at which automatic actions occur. These significant levels and typical corresponding actions are described in Table 1 and are shown on Figure 1 for approximate correlation. All trip functions and alarms are provided by the narrow or wide range level instruments.

Table 1

SUMMARY OF SIGNIFICANT REACTOR VESSEL LEVELS

Level	Action	Approximate Elevation Above TAF (ft)
Level 8	Main Turbine Stop Valve Closure, HPCI/HPCS Injection Terminated, Trip RCIC Turbine, Trip Reactor Feedwater Pumps and Condensate Booster Pumps, Scram (run mode only)	18-1/2
Level 7	Alarm	17
	Operating Reactor Level is Maintained Below the High Level Alarm and Above Low Level Alarm.	
Level 4	Alarm, Run Back Recirculation Flow on Loss of One Feed Pump.	16
Level 3	Scram and Run Back Recirculation Flow, Permissive for AD., Close RHR Shutdown Isolation Valves.	14-1/2
Level 2	Initiate Reactor Core Isolation Cooling System, Division 3 Diesel Generator and High Pressure Core Spray System, Close Isolation Valves, Except RHR Shutdown Isolation Valves and MSIV's, Shutdown Recirculation System.	11
Level 1	Initiate Residual Heat Removal Pumps and LPCS, Start Division 1 and 2 Diesel Generators, Close MISV's and Initiate ADS (in conjunction with other signals.)	1-1/2
Top of Active Fuel		0
Bottom of Active Fuel	Fuel Zone Indication	-12-1/2

FUNCTIONAL DESCRIPTION

All instrumentation, except the fuel zone instruments have a common reference zero.

All instrumentation, except the shutdown and fuel zone instruments, are calibrated based on normal power operating pressure and temperature conditions. The shutdown and fuel zone instruments are calibrated based on depressurized reactor conditions consistent with their functions.

The BWR water level indication scheme is based on two reference levels: one close to the bottom of the dryer skirt* for normal operation, upset and shutdown events, and one close to the top of the active fuel*. Four of the five instrument ranges (narrow, wide, upset, and shutdown ranges) have indicator and recorder scales which share the bottom of the dryer skirt as a common reference zero. Only the fuel zone instrument's scales are based on zero located at the top of the active fuel.

The narrow range instrumentation is provided to monitor and control reactor water level during normal power operating conditions. The reference point to the bottom of the dryer skirt is selected based on normal plant operation considerations. Specifically, high water level decreases the quality of steam delivered from the reactor due to degraded separator performance. Low water level that would permit passage of wet steam from the reactor due to inadequate skirt submergence could likewise potentially damage the main turbine and feedwater turbine. Hence a reference location relative to the bottom of the dryer skirt is appropriate. In addition to controlling water level during plant operation, the narrow range instrumentation also provides high and low water scram signals and ADS low level signals.

The wide range instruments are provided are provided as an extension of the narrow range to cover abnormal operating transients. The wide range scale encompasses the setpoints for initiation of HPCI/RCIC and low pressure ECCS and provides initiation signals for ADS and isolation systems. These instruments are calibrated for normal power operating pressure and temperature conditions to assure proper initiation of safety frunctions and to avoid

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*Throughout this memorandum, "bottom of the dryer skirt" refers to a location <u>near</u> the bottom of the dryer skirt. Similarily, "top of the active fuel" refers to an elevation at or somewhat above the top of the active fuel.

inadvertent scram or increased spurious signals that would jeopardize normal plant operations and result in reactor unavailability. For consistency, their zero reference is the same as that for narrow range instruments.

The upset range instrumentation is an upward extension of the normal range. It is provided to monitor unusually high water level transients that can be postulated to occur during reactor operation. Its reference zero is the same as the narrow range instrumentation.

The shutdown range is used for monitoring the reactor water level under shutdown conditions when the reactor is depressurized and flooded, prior to vessel head removal. For consistency, its reference zero is the same as the narrow range instrumentation.

Fuel zone level instrumentation is provided to indicate reactor water level following a large break LOCA (such as a double ended recirculation line break) and to verify core reflood by ECCS. It is not intended to give meaningful indication under any other plant transient or operating conditions or when the reactor is pressurized. Since the only function of the fuel zone instrumentation is to monitor level after a large loss of coolant accident, its zero reference location is selected as the top of the active fuel.

As indicated by the above discussion, the level instrumentation, calibration, location and scale ranges are based on the intended utilization and function of the instruments. It is evident, then, that there already exists an overall common water level reference for all normal operating and accident conditions except the large break LOCA, and that the water level zero reference for the large break LOCA differs from the others for a good reason.

This different reference level for the fuel zone level instrumentation is not confusing to the operator because he is familiar with the difference as a result of training and experience. The operator's awareness of the difference is constantly reinforced during routine control room surveillance since the fuel zone level is always off scale high and is adjacent to the wide range level instruments which are on scale.

Since the instruments, the calibration, and ranges are based on specific, well defined and logical functional criteria, operator confusion should not occur.

ASSESSMENT

To respond to the NRC's concern regarding a common water level reference, General Electric and the BWR Owners Group have reviewed the BWR water level indication system, giving attention to the following considerations:

- Responsiveness to the NRC's requirement
- Impact on safe reactor operation
- Compatibility with human factors concepts

The BWR water level instrumentation is based on an overall common reference zero for all normal operation, transient and accident conditions except the large break LOCA.

This design is based on the philosophy that the bottom of the dryer skirt is the most significant vessel elevation for normal, upset, and most postulated accident conditions. For the case of abnormal, diminishing water level, the trip functions automatically initiate emergency core coolant injection systems. With the redundancy of emergency systems available the reactor water level will generally not decrease to the top of the fuel for a large spectrum of accidents and transients. Further, the reactor operator's primary concern when in any decreasing low water level condition is to act so as to raise the water level. Any quantitative knowledge of the water level is much less significant than the fundamental and paramount task of restoring water level to near normal.

The fuel zone instrument, with its reference point (zero) at the top of the active fuel, becomes important for large design basis LOCAs as the primary verification of level. It provides secondary verification of level for small break LOCAs that ECCS has performed effectively. Correlation of this instrument with the bottom of the dryer skirt is not necessary.

CONCLUSION

General Electric and the BWR Owners' Group have concluded that the current BWR water level indication system is fully adequate to allow plant operators to respond properly under all postulated reactor conditions, and that there are no required design changes based on any plant safety considerations. Individual utilities may adopt certain design changes in response to the NRC request, this decision would be based on the individual utility's operating practices, operator training and procedures.

APPENDIX A

PARTICIPATING UTILITIES

NUREG-0737, II.K.3.27

This report applies to the following plants, whose owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 1-3
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Northern States Power	Monticello
Pacific Gas & Electric	Humboldt Bay 3
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	FitzPatrick
Detroit Edison	Enrico Fermi 2
Long Island Lighting	Shoreham
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

ENCLOSURE 14

NUREG-0737 ITEM II.k.3.44

ADEQUATE CORE COOLING FOR TRANSIENTS WITH A SINGLE FAILURE

Attached to this enclosure is a generic report titled "Adequate Core Cooling for Transients with a Single Failure" which was developed by General Electric Company for BWR Owners Group. Georgia Power Company has reviewed this report to confirm its applicability to Plant Hatch Units 1 and 2, and has concluded that for anticipated transients combined with the worst single failure the core remains covered. Analyses of further degraded conditions involving a stuck-open relief valve in addition to the worst transient and single failure have shown that, with proper operator action, the core remains covered and adequate core cooling is achieved.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 ITEM II.K.3.44

ADEQUATE CORE COOLING FOR TRANSIENTS WITH

A SINGLE FAILURE

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Summary

Analyses of the worst anticipated transient (loss of feedwater event) with the worst single failure (loss of a high pressure inventory makeup or heat removal system) were performed to demonstrate adequate core cooling capability. It is shown that, for the BWR/2 through BWR/6 plants, adequate core cooling is maintained for these worst-case conditions. Analyses of further degraded conditions involving a stuck-open relief valve in addition to the worst transient and single failure were also performed. The results show that, with proper operator action, the core remains covered and therefore adequate core cooling is achieved.

ADEQUATE CORE COOLING FOR TRANSIENTS WITH A SINGLE FAILURE

I. Introduction

This report has been prepared as the BWR Owners' Group generic response to NUREG-0737 Task Item II.K.3.44 which addresses the issue of adequate core cooling for transients with a single failure for those plants identified in Appendix A. The text of Item II.K.3.44 is as follows:

> "For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve should be included in this category."

At the outset it should be noted that the conditions described in II.K.3.44 (i.e., transients plus single failures) go beyond the current BWR design basis and that the item's reference to transients with multiple failures goes beyond the regulatory requirements as specified in Regulatory Guide 1.70, Rev. 3. The multiple failures specified involve consideration of a stuck-open relief valve (SORV) combined with the worst single failure. GE and the Owners Group continues to support the current BWR design basis approach. This report is intended to provide information to address Item II.K.3.44, but it does not reflect our intention to change the current BWR design basis approach.

It is shown that, for the GE BWR/2 through BWR/6 plants, the core remains covered for any transient with the worst single failure. This is achieved without any operator action to manually initiate emergency core cooling system (ECCS) or other inventory makeup systems. The worst transient with the worst single failure is shown to be the loss of feedwater (LOF) event with a failure of the high pressure ECCS or one isolation condenser (IC) loop, whichever is applicable.

For the bounding LOF event, studies which included even more degraded conditions have been documented in Reference 1. The degraded conditions cover the failure of HPCS (or HPCI or FWCI or IC) and one SORV. Reference 1 shows that the core will remain covered and therefore, that no fuel failure would occur.

II. Criteria, Scope and Assumptions

NUREG-0737 Item II.K.3.44 requires that the licensees demonstrate adequate core cooling to prevent the fuel from incurring significant damage for the anticipated transients combined with the worst single failure. In order to meet this requirement, either one of the following two criteria should be satisfied:

1. The reactor core remains covered with water until stable conditions are achieved; or

2. No significant fuel damage results from core uncovery.

For BWR plants, this report will show that Criterion 1 is met. The report makes the following assumptions:

a. A representative plant of each BWR product line, BWR/2 through BWR/6, is used to represent all of the plants of that product line.

b. The anticipated transients as identified in NRC Regulatory Guide 1.70, Revision 3 were considered.

c. The single failure is interpreted as an active failure.

d. All plant systems and components are assumed to function normally, unless identified as being failed.

III. Discussion

Table 1 lists all of the transients which were considered in this study. The event sequence of each transient was examined for each product line to determine the impact on core cooling. The following three factors were used to determine the worst transient and the worst single failure:

a. Reduction or loss of main feedwater or coolant makeup or heat removal systems, especially high pressure systems, e.g., HPCI, FWCI, HPCS, RCIC or IC.

b. Steam release paths causing rapid reactor coolant inventory loss, e.g., S/RV's, turbine, or turbine bypass valves.

c. Power level, especially the timing of scram.

Based on these considerations, a comparison was made among the transients in Table 1.

TABLE 1

SUMMARY OF INITIATING TRANSIENTS

(Reference: NRC Regulatory Guide 1.70, Revision 3)

1. Loss of Feedwater Heating
2. Feedwater Controller Failure - Maximum Demand
3. Pressure Regulator Failure - Open
4. Inadvertent Safety/Relief Valve Opening
5. Inadvertent Residual Heat Removal (RHR) Shutdown Cooling Operation
6. Pressure Regulator Failure - Closed
7. Generator Load Rejection
8. Turbine Trip
9. Main Steam Isolation Valve (MSIV) Closure
10. Loss of Condenser Vacuum
11. Loss of Normal AC Power
12. Loss of Feedwater Flow
13. Failure of RHR Shutdown Cooling
14. Recirculation Pump Trip
15. Recirculation Flow Control Failure - Decreasing Flow
16. Rod Withdrawal Error
17. Abnormal Startup of Idle Recirculation Pump
18. Recirculation Flow Control Failure - Increasing Flow
19. Fuel Loading Error
20. Inadvertent Startup of High Pressure Core Spray (HPCS) or High Pressure Coolant Injection (HPCI) or Feedwater Coolant Injection (FWCI) or Isolation Condenser (IC), whichever is applicable.

In Reference 2, the events of Table 1 are compared in detail for a typical BWR/4 plant. In particular the impact on core cooling for each transient is evaluated by comparison to the analysis results for the LOF event in the section titled "Applicability of Analyses." It is found that the LOF event is the most severe transient from the core cooling viewpoint due to its rapid depletion of reactor coolant inventory. This conclusion has generic applicability to all BWR product lines covered by this study.

The same approach was also used to select the single failures which would pose the greatest challenge to core cooling. Among all of the possible failures considered (Table 2), the following failures are identified as the most important ones:

1. Failure of HPCI or HPCS or FWCI or one IC loop, whichever is applicable.

2. Failure of RCIC.

3. One of the S/RV's, which has opened as a result of the transient, fails to close.

Items 1 and 2 are the possible limiting failures because they represent loss of high pressure inventory makeup or heat removal systems which would be relied on following a loss of feedwater event. Item 3 is a possible limiting failure, because it results in the largest steam release rate from the vessel compared to other possible release paths (e.g., a stuck-open turbine bypass valve). No other failures identified in Table 2 result in a direct challenge to core cooling capability.

TABLE 2

LIST OF SINGLE FAILURES WHICH CAN POTENTIALLY DEGRADE THE COURSE OF A BWR TRANSIENT

1. One or all of the bypass valves fail to modulate open when required.
2. One of the bypass valves, which has opened as a result of the transient, fails to close.
3. Failure to trip the turbine or feedwater pumps on high water level.
4. One main steam isolation valve (MSIV) fails to close when required.
5. One of the safety/relief valves fails to open when required.
6. One of the safety/relief valves, which has opened as a result of t [illegible]nsient, fails to close.
7. Failure to trip one recirculation pump.
8. Failure to run back the recirculation pumps.
9. Failure of high pressure coolant injection (HPCI) or high pressure core spray (HPCS) or feedwater coolant injection (FWCI) or one isolation condenser (IC) loop, whichever is applicable.
10. Failure of reactor core isolation cooling (RCIC) or one IC loop, whichever is applicable.
11. Failure of one low pressure coolant injection (LPCI) loop or the low pressure core spray (LPCS) system.

TABLE 2 (CONT'D)

12. Loss of one residual heat removal (RHR) system heat exchanger.

13. A single control rod stuck while the remainder of the control rods are moving.

14. Failure to achieve the rod block function (i.e., a single control rod will withdraw upon erroneous withdrawal demand).

15. Loss of one diesel generator if loss of AC power was the initiating event.

Because of the relatively low steam loss capacity through one SORV (Failure 3, Page 5) compared to the makeup water capacity of the highest capacity makeup water system, the failure of the highest capacity high pressure makeup system (Failure 1, Page 5) would be worse than a stuck open relief valve (Failure 3, Page 5). For example, for a typical BWR/4, representative values of HPCI makeup and S/RV flow are 18% and 6% of rated feedwater flow, respectively. Because of the higher makeup rate of HPCI/HPCS relative to RCIC (3% of rated feedwater flow), Failure 1 would be worse than Failure 2. Table 3 lists the worst combination of transient and single failure for the GE BWR product lines covered by this study.

Even with the worst single failure in combination with the LOF event, the RCIC or at least one IC loop will function to provide makeup and/or to remove decay heat while the vessel pressure remains high. The design basis for the RCIC or the IC is such that they are capable of removing decay heat with the vessel being isolated. Analyses of the LOF event with the worst single failure have been performed to support this conclusion. For example, for BWR/2 plants, such analyses are documented in Reference 1 Table 3.2.1.1.5-5. These analyses show that the isolation condenser heat removal capacity is greater than the decay heat generation rate and will lead to a safe and stable condition. Similar analyses have been performed for representative plants with the RCIC system. These analyses show that for the worst transient with the worst single failure, the minimum water level for different BWR product lines ranges from 6 ft to 11 ft above the top of the active fuel.

With even more degraded conditions, i.e., one SORV in addition to the worst case transient with the worst single failure, reference plant analyses in Reference 1 Tables 3.2.1.1.5-9 and 3.2.1.1.5-10 show that for the plants analyzed the RCIC system can automatically provide sufficient inventory to keep the core covered even with a single failure plus a SORV. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capability. If a plant should not have this

TABLE 3

THE WORST CASE OF TRANSIENT WITH A SINGLE FAILURE FOR DIFFERENT BWR PRODUCT LINES

Product Line	Transient with a Single Failure (The Worst Case)
BWR/2	LOF + Failure of one IC Loop (Oyster Creek only) LOF + Failure of FWCI (Nine Mile Point only)
BWR/3	LOF + Failure of FWCI (Millstone only) LOF + Failure of HPCI (others)
BWR/4	LOF + Failure of HPCI
BWR/5	LOF + Failure of HPCS
BWR/6	LOF + Failure of HPCS

capability, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV. It should be noted that manual depressurization is the proper operator action for all plants during loss of inventory conditions when the high pressure cooling system(s) are unable to restore and maintain RPV level. These proper operator actions are allowed for in the NUREG-0737 requirement.

For plants without RCIC, manual depressurization will avoid core uncovery for the case of LOF plus worst single failure plus SORV.

IV. Conclusion

The anticipated transients in NRC Regulatory Guide 1.70, Revision 3 were reviewed for all BWR product lines BWR/2 through BWR/6 from a core cooling viewpoint. The LOF event was identified to be the most limiting transient which would challenge core cooling. The BWR is designed so that the high pressure makeup or inventory maintenance systems or heat removal systems (HPCI, HPCS, FWCI, RCIC or IC) are independently capable of maintaining the water level above the top of the active fuel given a loss of feedwater. The detailed analyses show that even with the worst single failure in combination with the LOF event, the core remains covered.

Furthermore, even with more degraded conditions involving one SORV in addition to the worst transient with the worst single failure, studies show that the core remains covered during the whole course of the transient either due to RCIC operation or due to manual depressurization.

It is concluded that for anticipated transients combined with the worst single failure the core remains covered. Additionally, it is concluded that for severely degraded transients beyond the design basis where it is assumed that a S/RV sticks open and an additional failure occurs the core remains covered with proper operator action.

V. References

1. Section 3.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, March 31, 1980

2. Section 3.2.2 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, June 30, 1980

3. Section 3.5.2.1 (prepublication form) of "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," NEDO-24708, August 31, 1979

APPENDIX A

PARTICIPATING UTILITIES

NUREG-0737, II.K.3.44

This report applies to the following plants, whose owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 1-3, Quad Cities 1 & 2
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Jersey Central Power & Light	Oyster Creek 1
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	Fitzpatrick
Tennessee Valley Authority	Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 & 2
Vermont Yankee Nuclear Power	Vermont Yankee
Detroit Edison	Enrico Fermi 2
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2
Long Island Lighting	Shoreham

ENCLOSURE 15

NUREG-0737 ITEM II.k.3.45

ALTERNATE MODES OF DEPRESSURIZATION

Attached as part of this enclosure is a generic report titled "Alternate Modes of Depressurization" developed by General Electric Company for the BWR Owners Group. Georgia Power Company has reviewed this report and concurs with its conclusions.

BWR OWNERS' GROUP EVALUATION OF

NUREG-0737 ITEM II.K.3.45

ALTERNATE MODES OF DEPRESSURIZATION

TABLE OF CONTENTS

SUMMARY

Analyses of depressurization rates other than full ADS were performed to determine the effect on reactor vessel integrity and core cooling capability. It is shown that:

1. Vessel integrity limits are not exceeded for full ADS blowdown,

2. For slower depressurization rates, there is little benefit on vessel fatigue usage relative to full ADS blowdown, and

3. Slower depressurization rates can have an adverse impact on core cooling capability.

I. Introduction

The feasibility study reported herein addresses NUREG-0737 item II.K.3.45 which states,

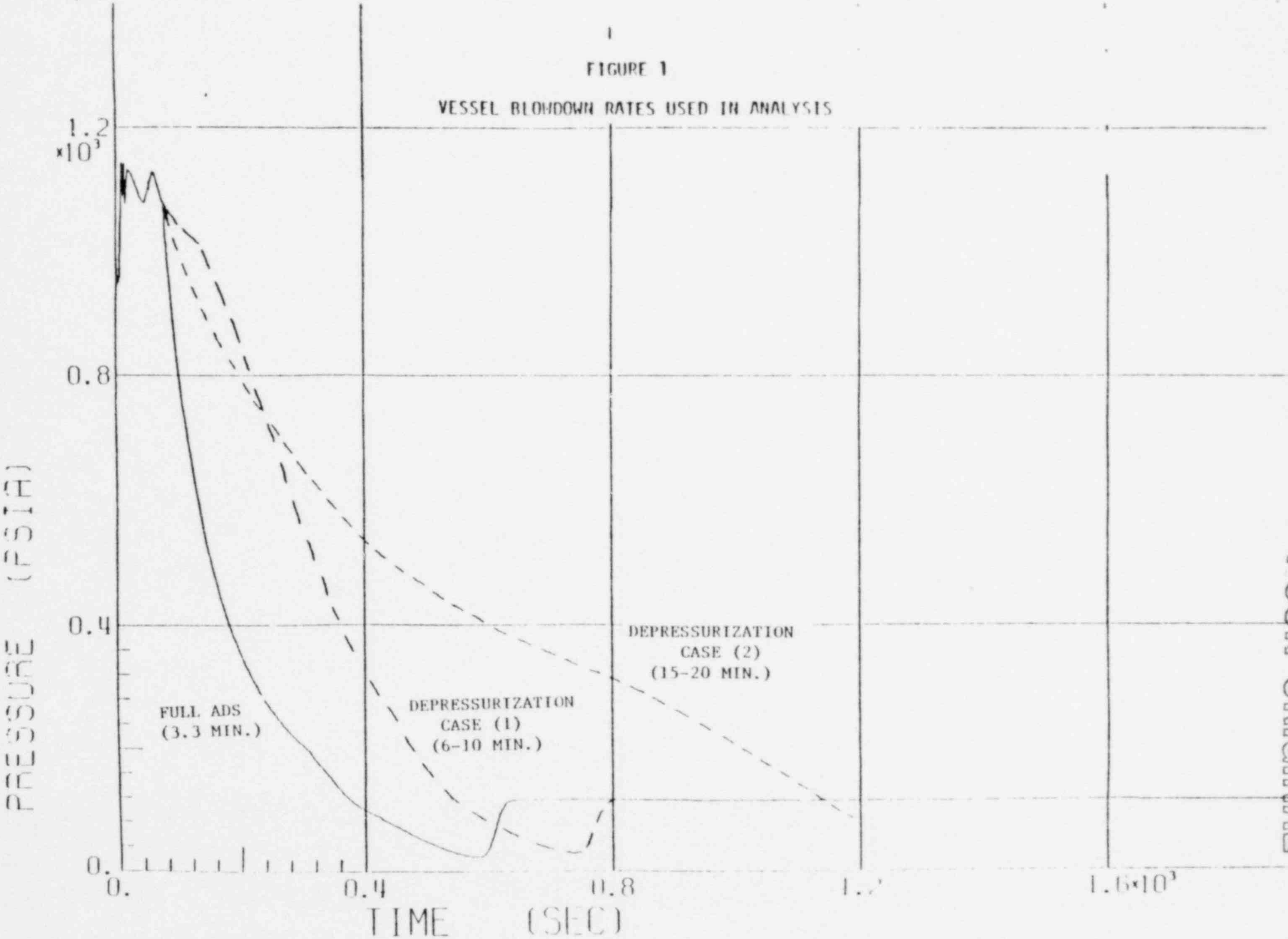
> "Analyses to support depressurization modes other than full actuation of the ADS (e.g., early blowdown with one or two SRV's) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown".

An evaluation of alternate modes of depressurization other than full actuation of the Automatic Depressurization System (ADS) is made for the plants listed in Appendix A with regard to the effect of such reduced depressurization rates on core cooling and vessel integrity.

Depressurization by full ADS actuation constitutes a depressurization from about 1050 psig to 180 psig in approximately 3.3 minutes. Such an event, which is not expected to occur more than once in the lifetime of the plant, is well within the design basis of the reactor pressure vessel. This conclusion is based on the analysis of several transients requiring depressurization via the ADS valves. Results of these analyses indicate that the total vessel fatigue usage is less than 1.0. Therefore, no change in the depressurization rate is necessary. However, to comply with the above request reduced depressurization rates were analyzed and compared with the full ADS actuation. The alternate modes considered cause vessel pressure to traverse the same pressure range in 1) depressurization case 1 (ranges from 6-10 minutes depending on plant size and ADS capacity) and 2) depressurization case 2 (ranges from 15-20 minutes). The case 2 depressurization bounds the possible increase in depressurization time by producing an undesirably long core uncovered time. The case 1 depressurization gives the results of an intermediate depressurization. These modes are achieved by opening a reduced number of relief valves. These blowdown rates are illustrated by Figure 1.

FIGURE 1

VESSEL BLOWDOWN RATES USED IN ANALYSIS



II. Assumptions

The major assumptions used for the core cooling analysis are:

1. No high pressure cooling systems are available.
2. All low pressure ECC systems are available.
3. Assumptions as stated in NEDO-24708, Sect. 3.1.1.3, "Justification of Analysis Methods"; which includes the use of 1978 ANS Decay Heat (mean value).

III. Results

A. Vessel Integrity

The depressurization events considered are full ADS blowdown and blowdown over 10 and 20 minute intervals. The reactor vessel stresses for these events are within the acceptance stress limits defined by ASME Code Section III for emergency conditions (Level C). The core support structures and other safety related internal components are also within applicable emergency condition stress limits.

The ADS operating conditions which affect fatigue usage of vessel or core support structures are not significantly different for fast and slow blowdown events. Specific calculations of fatigue usage are not required for emergency conditions (Level C). However, available pressure vessel fatigue analyses show the usage per event to be <0.1 per full ADS event.

In summary, reactor vessel and core support structure integrity is assured for the blowdown rates considered if an ADS event should occur, and reduced rates of depressurization do not significantly decrease fatigue usage.

B. Core Cooling Capability

Examination of the reduced depressurization rates under consideration with respect to core cooling concerns shows that,

1. Vessel depressurization for a case 2 blowdown (15-20 minutes) causes the core to be uncovered for a lengthy period of time even assuming system initiation at the earliest reasonable time.

2. Vessel depressurization for a case 1 blowdown (6-10 minutes), when actuated at the same level as the full ADS case, will result in less vessel inventory at the time of ECCS injection and can result in longer periods of core uncovery.

3. Vessel depressurization for a case 1 blowdown (6-10 minutes) when actuated considerably earlier than at the ADS initiation setpoint can result in some improvement in core cooling. However, the operator is required to act more quickly in these cases (i.e., within 1-6 minutes after the accident). This earlier depressurization also reduces the time available to start high pressure system injection and hence to avoid the need for manual depressurization. It also increases the frequency of depressurization.

The results of the calculations are presented in Tables 1 through 4. They show the total core uncovered time and remaining vessel inventory at the time of low pressure ECCS injection. A discussion of these results follows in Section IV.

IV. Discussion

The results are based upon calculations performed with the assumptions stated earlier using a representative BWR/3 and a BWR/6 to show consistency of results across the product lines. The transients considered are an outside steamline break and a stuck-open relief valve. The ADS will depressurize the vessel to the low pressure ECCS injection setpoint when no high pressure cooling systems are available. The depressurizations used are initiated at different times based on the downcomer water level. The first initiation time considered is when the water level is at the top of the active fuel which is consistent with the original design for most plants and thus is the basis for comparison. The second initiation time considered is the downcomer water level of 34 feet from the bottom of the vessel which still provides the operator with a reasonable time to attempt to start the high pressure systems. The last initiation time considered is the high pressure make-up system setpoint (Level 2 for BWR/6 and Level 1 for BWR/3) plus 60 seconds which is the earliest time in which depressurization could be expected to occur.

The core cooling criteria used in assessing the impact of a reduced depressurization rate are:

1. Inventory in the core and lower plenum at the time of low pressure ECCS injection as predicted by the SAFE[1] model.

2. The total time which the top of the active fuel (TAF) remains uncovered as predicted by the SAFE[1] model.

The first criterion demonstrates the increased mass loss due to boiloff for the longer blowdown, since mass loss due to flashing will be independent of the depressurization rate providing the boundary pressure values are the same for all the rates. The second criterion is a measure of the resultant core temperature.

Ref. 1 NEDO-24708 "Additional information required for NRC Staff Generic Report on Boiling Water Reactors", August, 1979.

Table 1 gives the results for a BWR/6 assuming an outside steamline break. As the length of depressurization is increased the vessel inventory at the time of ECCS injection decreases and the total core uncovered time increases. Table 1 further shows that for actuation times based on higher water levels (i.e., 34' and Level 2 + 60 seconds) longer depressurizations exhibit the same trends. Furthermore, for any particular depressurization rate, raising the actuation level increases the vessel inventory at ECCS injection and decreases the total core uncovered time. However, this also decreases the time the operator has available to try to get high pressure level control systems working in order to avoid the need to depressurize.

Table 2 shows that these same results are exhibited for the case of a stuck open relief valve. Table 3 shows the results for a BWR/3 assuming an outside steamline break. Examination of the table shows the same trends as Table 1, and therefore the results are applicable to all product lines. Table 4 shows that these general trends are independent of the models used by exhibiting the same trends for a BWR/3 using standard Appendix K licensing assumptions.

V. Conclusion

The cases considered show that no appreciable improvement can be gained by a slower depressurization based on core cooling considerations. A significantly slower depressurization rate will result in increased core uncovered time. A moderate decrease in the depressurization rate necessitates an earlier actuation time resulting in less time available for operator action to start high pressure ECCS without significant benefit to vessel fatigue usage. This will also result in an increased frequency of ADS actuation.

Finally, it is of paramount importance to note that the ADS is not a normal core cooling system; it is a backup for high pressure cooling systems (feedwater, RCIC, HPCI/S). If ADS operation is ever required in a BWR, it will be because core cooling is threatened. Since a full ADS blowdown is well within the design basis of the reactor pressure vessel and ADS is properly designed to minimize the threat to core cooling, no change in the depressurization rate is necessary.

TABLE 1

RESULTS FOR BWR/6 OUTSIDE STEAMLINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

DEPRESSURIZATION CASE	DEPRESSURIZATION INITIATION LEVEL	DEPRESSURIZATION INITIATION TIME (SEC)	CORE UNCOVERED TIME (SEC)	LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS)
FULL ADS	TAF*	1086	26	1.603×10^5
CASE 1	TAF	1086	117	1.528×10^5
CASE 1	34'	610.6	10	1.779×10^5
FULL ADS	Level 2† + 60 Sec.	78.3	No Uncovery	1.993×10^5
CASE 1	Level 2 + 60 Sec.	78.3	No Uncovery	1.937×10^5
CASE 2	Level 2 + 60 Sec.	78.3	390	1.755×10^5

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 2

RESULTS FOR BWR/6 STUCK-OPEN RELIEF VALVE
NO HIGH PRESSURE SYSTEMS AVAILABLE

DEPRESSURIZATION CASE	DEPRESSURIZATION INITIATION LEVEL	DEPRESSURIZATION INITIATION TIME (SEC)	CORE UNCOVERED TIME (SEC)	LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS)
FULL ADS	TAF*	642.6	No Uncovery	1.836×10^5
CASE 1	TAF	642.6	15	1.787×10^5
CASE 1	34'	391.8	No Uncovery	1.889×10^5
CASE 1	Level 2 † + 60 Sec.	77.7	No Uncovery	1.961×10^5

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 3

RESULTS FOR BWR/3 OUTSIDE STEAMLINE BREAK
NO HIGH PRESSURE SYSTEMS AVAILABLE

DEPRESSURIZATION CASE	DEPRESSURIZATION INITIATION LEVEL	DEPRESSURIZATION INITIATION TIME (SEC)	CORE UNCOVERED TIME (SEC)	LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS)
FULL ADS	TAF*	1527.8	155	2.027×10^5
CASE 1	TAF	1527.8	170	1.975×10^5
CASE 1	34'	701.6	51	2.291×10^5
FULL ADS	Level 1 † + 60 Sec.	364.4	No Uncovery	2.446×10^5
CASE 1	Level 1 + 60 Sec.	364.4	10	2.394×10^5

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

TABLE 4

RESULTS FOR BWR/3 OUTSIDE STEAMLINE BREAK
ON APPENDIX K ASSUMPTIONS WITH NO HIGH PRESSURE SYSTEMS

DEPRESSURIZATION CASE	DEPRESSURIZATION INITIATION LEVEL	DEPRESSURIZATION INITIATION TIME (SEC)	CORE UNCOVERED TIME (SEC)	LIQUID INVENTORY IN CORE AND LOWER PLENUM AT LOW PRESSURE ECCS INJECTION (LBS)
FULL ADS	TAF*	759.4	264	1.960×10^5
CASE 1	TAF	759.4	277	1.913×10^5
FULL ADS	Level 1 † + 60 Sec.	145.6	175	2.210×10^5
CASE 1	Level 1 + 60 Sec.	145.6	191	2.165×10^5

*TOP OF ACTIVE FUEL

†HIGH PRESSURE INITIATION SETPOINT PLUS 60 SECONDS

GENERAL ELECTRIC

APPENDIX A

NUREG-0737 ITEM II.K.3.45

This report applies to the following plants, whose Owners participated in the report's development.

Boston Edison	Pilgrim 1
Carolina Power & Light	Brunswick 1 & 2
Commonwealth Edison	LaSalle 1 & 2, Dresden 2 & 3, Quad Cities 1,2
Georgia Power	Hatch 1 & 2
Iowa Electric Light & Power	Duane Arnold
Jersey Central Power & Light	Oyster Creek 1
Niagara Mohawk Power	Nine Mile Point 1 & 2
Nebraska Public Power District	Cooper
Northeast Utilities	Millstone 1
Northern States Power	Monticello
Philadelphia Electric	Peach Bottom 2 & 3; Limerick 1 & 2
Power Authority of the State of New York	Fitzpatrick
Tennessee Valley Authority	Browns Ferry 1-3; Hartsville 1-4, Phipps Bend 1 & 2
Vermont Yankee Nuclear Power	Vermont Yankee
Detroit Edison	Enrico Fermi 2
Long Island Lighting	Shoreham
Mississippi Power & Light	Grand Gulf 1 & 2
Pennsylvania Power & Light	Susquehanna 1 & 2
Washington Public Power Supply System	Hanford 2
Cleveland Electric Illuminating	Perry 1 & 2
Houston Lighting & Power	Allens Creek
Illinois Power	Clinton Station 1 & 2
Public Service of Oklahoma	Black Fox 1 & 2

ENCLOSURE 16

NUREG-0737 ITEM III.A.2

EMERGENCY PREPAREDNESS

Submittal of information required under this item will be made under a seperate cover letter. (Due Date 1/2/81)

ENCLOSURE 17

NUREG-0737 ITEM III.D.3

DESCRIPTION OF IN-PLANT AIRBORNE RADIOIODINE

SAMPLING AND ANALYSIS

The in-plant airborne radioiodine portable sampling system under accident conditions consists of a minimum of 22 low volume air samplers. These samplers are all adapted to hold silver zeolite cartridges.

The sample media to be used to select radioiodine over xenon consists of 100 silver zeolite cartridges with an additional 100 more on order. Stock quantity of charcoal cartridges on site is 1000 at all times. A flushing method and device to flush charcoal cartridges and silver zeolite if necessary is available for emergencies.

The flushing device consists of a holder for the cartridge, a regulator, flow meter, industrial breathing air bottles, 50 feet of tygon tubing. The flushing method consists of placing the cartridge in the holder and running the discharge tygon tubing outside the room or into a hood exhaust. The sample will be purged at 3 CFM (95% retention for iodine) with air until free of most of its xenon.

The sample analysis equipment for radioiodine consists of 2 Erberline SAM-2 dual channel analyzers, 2 RD-22 Sodium Iodide (Tℓ) detectors with lead shields and counting shelfs. Both SAM-2's are set up for 364 KEV. One SAM-2 is located at the Emergency Operating Facility and one at the temporary Technical Support Center. Should a more suitable location be found, these instruments will be relocated. The SAM-2's would only be used if the normal counting room could not be used due to background and the Ge-Li, Multi-Channel, and Computer could not be moved for some reason as planned to the Technical Support Center, the Emergency Operating Facility, or other location.

Procedures have been written for the equipment to determine iodine concentrations. Associated training has been given on how to use this equipment and procedures for all radiation protection technicians and supervisors who would be involved in determining radioiodine concentrations under emergency conditions.

ENCLOSURE 18

NUREG 0737 ITEM III.D.3.4

CONTROL ROOM HABITABILITY

Attached as part of this enclosure is a report made in response to the questions of Attachment 1 of item III.D.3.4 of NUREG-0737. The amounts of some items stored in the control room (e.g. food, water, and KI tablets) are variable and are examples of typical inventories. They should not be considered as committed minimums. The necessity for and the appropriate valve for an established minimum quantity of such items in the control room is under consideration. Resolution of this question is expected by July 1, 1981.

RESPONSE TO

III.D.3.4, ATTACHMENT 1, INFORMATION REQUIRED FOR CONTROL-ROOM HABITABILITY EVALUATION

1 Control-room mode of operation, i.e., pressurization and filter recirculation for radiological accident isolation or chlorine release

Response: Refer to FSAR 6.4.1.2.2. The system operates in the pressurization mode for radiological events, and in the isolation mode for chlorine releases.

2 Control-room characteristics

(a) air volume control room
(b) control-room emergency zone (control room, critical files, kitchen, washroom, computer room, etc.)

Response: As stated in FSAR 15.1.42.1.6.1.f, the net free volume is 93,500 cubic feet. This includes the adjacent chart room, shift engineer's office, instrument and maintenance equipment area kitchen, and toilet, all of which are serviced by the control room habitability system.

(c) control-room ventilation system schematic with normal and emergency air-flow rates

Response: Refer to sheets 1 and 2 of FSAR Figure 9.4-1.

(d) infiltration leakage rate

Response: For the pressurization, there is no inleakage; refer to the first paragraph of FSAR 15.1.42.1.1. For the isolation mode (for chlorine release), 60 cfm of contaminated air was assumed to enter the isolated control room: refer to the last paragraph of FSAR 15.1.42.1.6.

(e) high efficiency particulate air (HEPA) filter and charcoal adsorber efficiencies

Response: The efficiencies and related HEPA filter and charcoal filter characteristics are given in FSAR Table 6.4-1.

(f) closest distance between containment and air intake

Response: The shortest horizontal distance from the vertical axis of the primary containment to the control room air intake is approximately 136 feet, generally west from the containment above the turbine building; there is a drop of about 56 feet to the air inlet at elevation 185 feet. Refer to Figure 1, attached.

The direct bypass leakage is assumed to be 0.9% of the total containment leakage, as stated in the Hatch Unit 2 FSAR. It is released to the environment directly with no holdup or filtration. The MISV leakage is quantified by assuming that all four main steam lines leak at the technical specification limit of 11.5 scfh.

Radioactivity leakage past the isolation valves could be released through the outboard MSIV stems into the steam tunnel, or continue down the steam lines to the stop valves and into the turbine condenser complex. Leakage into the steam tunnel is exhausted by the SGTS filtration system, thus eliminating it as a bypass pathway. Leakage down the steam lines is subject to plateout and delay within the lines. Reference 1, Section 5.1.2, discusses iodine removal rates which can be applied to calculate plateout on the piping and turbine condenser surfaces. Elemental and particulate iodine DFs of over 100 can be calculated for small travel distances and large travel times down the steam lines, considering the small volumes of leakage which leak past the valves. A DF of 10 is assumed for plateout and partitioning of iodine in the steam lines, turbine, and condenser. It was also assumed that the MSIV leakage is confined to the steam line, turbine condenser volume complex from which it will leak at 1% of the turbine condenser volume per day. This leak rate and DF are consistent with the assumptions used for the CRDA in SRP 15.4.9. The volumetric leakage from the condenser would be approximately the same as inleakage. Furthermore, the MSIV leakage will be cooling and condensing as it travels down the lines. Therefore, it is not anticipated that the turbine condenser volume would pressurize.

The activity which enters the main control room may be the result of direct bypass leakage, MSIV leakage, or SGTS exhaust in the outside air. However, the exhaust from the SGTS can be neglected. The SGTS has filter efficiencies of 95% and the release point is a high stack so $X/_Q$ values will be very small. Therefore, the resulting doses will be several orders of magnitude lower than doses resulting from other sources.

Atmospheric dispersion factors are based on Murphy's model (Reference 2) as calculated in the Hatch Unit 2 FSAR. A ground level release is assumed from the reactor building to the control room intake. Use of Halitsky's model would be expected to give lower $X/_Q$s.

(g) layout of control room, air intakes, containment building, and chlorine, or other chemical storage facility with dimensions.

Response: Refer to Figure 1 for the outside plan with dimensions.

(h) control-room shielding including radiation streaming from penetrations, doors, ducts, stairways, etc.

Response: Refer to Figure 12.3-14. New calculations have been made which show that, using conservative assumptions and accepted analytical procedures, the whole body gamma dose received by any operator over a 30-day period will not exceed 1.5 Rem, well below the LOCA allowable of 5.0 Rem. A detailed description of this calculation follows.

(1) General Licensing Consideration

The Hatch Unit 1 plant and control room were licensed on the basis that all containment leakage was collected by the SGTS and released through the main stack. In 1975, NRC issued Regulatory Guide 1.96 on the subject of MSIV Leakage Control Systems (LCS). Regulatory Guide 1.96 indicated that operating plants (Hatch Unit 1) may continue operation without an MSIV-LCS unless recurring leakage indicates a significant problem.

The requirements to show acceptable post LOCA doses in the control room (NRC's letter of 5/7/80) result in the need to reevaluate the DBA-LOCA and the subsequent pathways, including Hatch Unit 1 MSIV leakage, for release of radioactivity.

(2) Methodology

The calculation is based on guidelines presented in SRP 6.4 and Regulatory Guide 1.3.

(A) Assumptions and Bases

Regulatory Guide 1.3 was used to determine activity levels in the containment following a DBA-LOCA. Specifically, 100% of the noble gases and 25% of the iodines in the core are assumed to be released and mixed instantaneously in the primary containment free volume. Activity releases are based on a containment leakage rate of 1.2% per day. The majority of the containment leakage will be collected in the reactor building and exhausted to the atmosphere through the SGTS as an elevated release from the main stack. However, there exist certain release pathways from the containment which will bypass the SGTS filters, specifically, direct bypass and main steam isolation valve leakage.

(3) Results

The radiological exposures to personnel occupying the control room are presented in Table 1. All doses are within the SRP 6.4 and GDC 19 guidelines values.

Table 1: Post LOCA Doses (30 Day) to Control Room Occupants

Dose Type	Calculated Dose (Rem)	Limit (Rem)
Thyroid	26.2	30
Whole Body	0.097	5
Beta Skin	1.70	30

(4) References

1. NUREG/CR-0009, "Technological Basis for Models of Spray Washout of Airborne Cotaminants in Containment Vessels": A. K. Posta, R. R. Sherry, P. S. Tam, October 1978.

2. K. G. Murphy and K. M. Compe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," 13th AEC Air Cleaning Conference.

The above calculated whole body dose does not include the direct gamma streaming through the doorway nearest the containment (shown on the upper left of Figure 12.3-14). This dose has been calculated as 1.91 mr/hr; assuming the operator stood in the doorway for 24 hours a day for the full 30 days, this would add (1.91 x 24 x 30 ÷ 1000 =) 1.375 Rem, for a total of (0.097 + 1.375 =) 1.47 Rem.

(i) automatic isolation capability-damper closing time, damper leakage and area

Response: Refer to FSAR 15.1.42.1.6
Individual damper leakage is not measured; manufacturer's data specifies less than 1 cfm for the worst damper known in the system, at 0.125 inches w.g. (The pressure in the pressurization mode.) As 60 cfm was used in the analyses, the calculation is very conservative.

Overall leakage (dampers, doors, and all other paths) is periodically proven by test to be acceptable when the control room is pressurized for test.

(j) chlorine detectors or toxic gas (local or remote)

Response: The location of chlorine detectors is stated in FSAR 6.4.1.3. Instrument response times are given in FSAR 15.1.42.1.6.

(k) self-contained breathing apparatus availability (number)

Response: Ten self-contained units are kept in the control room with at least eight additional operable units on site.

(l) bottled air supply (hours supply)

Response: Thirty two spare bottles are kept in the control room, and at least 38 more on site. Each bottle represents a minimum of 30 minutes of use by one person.

(m) emergency food and potable water supply (how many days and how many people)

Response: No food is presently stored in the control room. However, no credible event would prevent supplying food, if necessary, from outside within several hours. Essentially unlimited potable water is available as long as the potable water system pumps are operable. Should offsite power be lost for an extended time, it would be necessary to bring water in also.

(n) control-room personnel capacity (normal and emergency)

Response: Normally, with both units in operation, there would be ten people in the control room; refer to FSAR 13.1.2.3. During emergencies, this number would increase, probably to a maximum of 18, depending on specific conditions and requirements.

(o) potassium iodide drug supply

Response: No potassium iodide is stored in the control room. However, at the present time 200 KI tablets are available on-site.

3 Onsite storage of chlorine and other hazardous chemicals

(a) total amount and size of container

Reponse: As stated in FSAR 15.1.42.1.6., the maximum inventory of chlorine will be sixteen containers, each with a capacity of one ton. There is no significant amount of any other potentially hazardous chemical.

(b) closest distance from control-room air intake

Response: As stated in FSAR 15.1.42.1.6.1.d, the approximate distance from the chlorine storage building to the control room air intake is 700 feet. In addition, the air intake is at elevation 185 feet; the chlorine is stored at grade, approximately 135 feet elevation.

4 Offsite manufacturing, storage, or transportation facilities of hazardous checmials

(a) identify facilities within a 5-mile radius;

(b) distance from control room

(c) quantity of hazardous chemicals in one container

Response: As stated in FSAR Section 2.2, there are no industrial facilities of consequence within five miles of the plant.

(d) frequency of hazardous chemical transportation traffic (Truck, rail, and barge)

Response: As stated in FSAR Section 2.2, there is no rail line within 10 miles of the plant. There is no significant ship or barge traffic on the Altamaha River at or upstream of the plant.

Highway U.S. 1 passes about 3500 feet west of the plant; occasional small quantities (i.e., truck load) of various materials use this route. However, the distance and small unit quantities preclude this as a hazard to the plant.

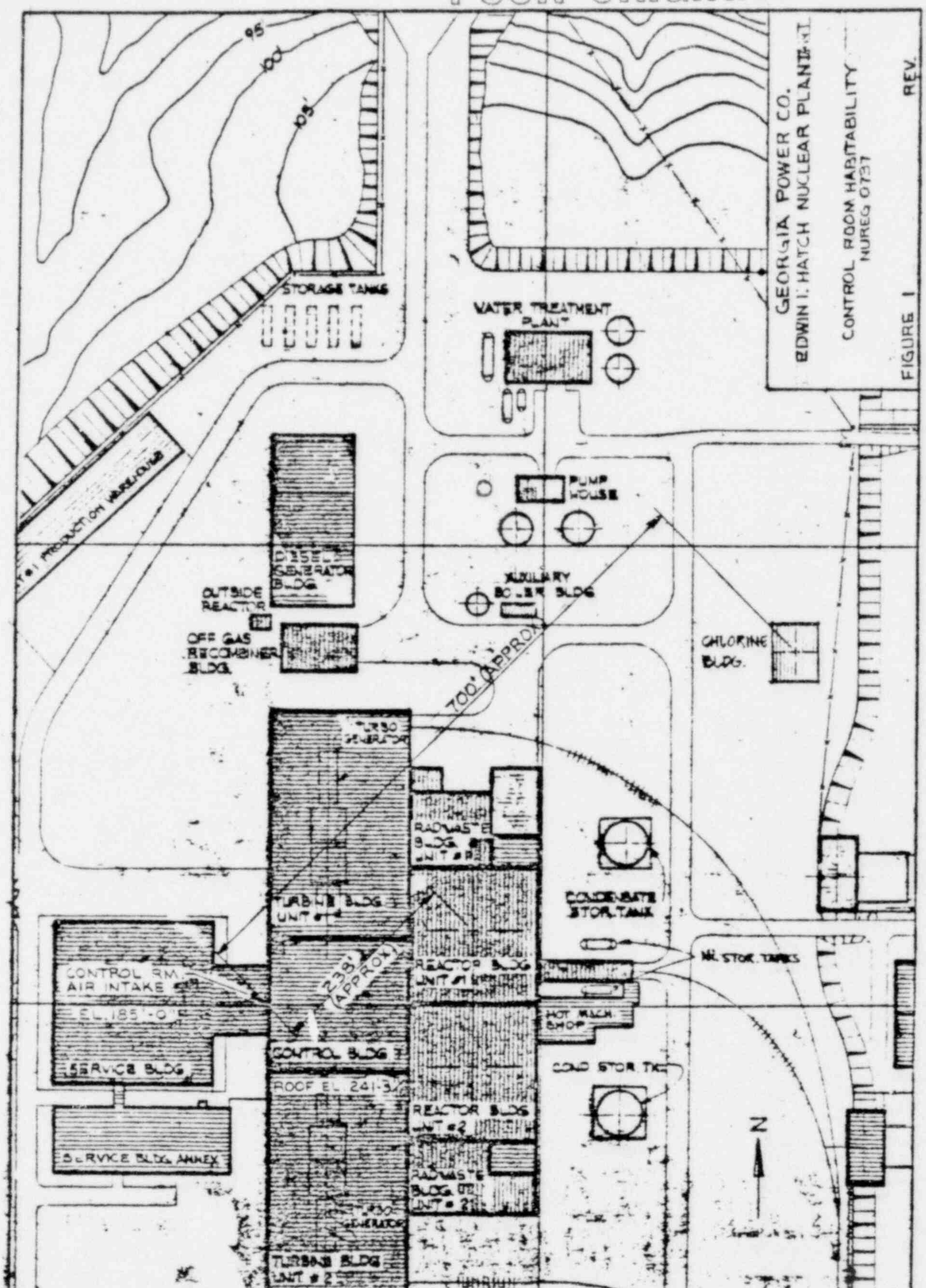
5 Technical specifications (refer to standard technical specifications)

(a) chlorine detection system

Response: The chlorine detection system will be tested in accordance with 3.3.6.7/4.3.6.7 of the standard technical specifications (p. 3/4 3-58).

(b) control-room emergency filtration system including the capability to maintain the control-room pressurization at 1/8-in water guage, verification of isolation by test signals and damper closure times, and filter testing requirements.

Response: The control room emergency filtration system will be tested in accordance with 3/4.7.2 of the standard technical specifications. It should be noted, however, that the STS requires only 0.1 inches differential pressure in lieu of the 0.125 inches indicated above. The Operator's commitment is to the STS value of 0.1 inches.


GEORGIA POWER CO.
EDWIN I. HATCH NUCLEAR PLANT
CONTROL ROOM HABITABILITY
NUREG 0737
FIGURE 1
REV.
95
100
105'
STORAGE TANKS
WATER TREATMENT PLANT
PUMP HOUSE
DIESEL GENERATOR BLDG.
OUTSIDE REACTOR
OFF GAS RECOMBINER BLDG.
AUXILIARY BOILER BLDG.
CHLORINE BLDG.
700' (APPROX.)
TURBO GENERATOR
RADWASTE BLDG. UNIT #1
TURBINE BLDG. UNIT #1
CONDENSATE STOR. TANK
CONTROL RM. AIR INTAKE
EL. 185'-0"
238' (APPROX.)
REACTOR BLDG. UNIT #1
N2 STOR. TANKS
HOT MACH. SHOP
SERVICE BLDG.
CONTROL BLDG.
COND. STOR. TK.
ROOF EL. 241'-3"
REACTOR BLDG. UNIT #2
SERVICE BLDG. ANNEX
RADWASTE BLDG. UNIT #2
TURBO GENERATOR
TURBINE BLDG. UNIT #2
N

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6.4 HABITABILITY SYSTEMS

6.4.1 HABITABILITY SYSTEMS FUNCTIONAL DESIGN

This system was installed with Unit 1 and has been in operation since 1974. 44

The main control room habitability systems are designed to provide safety and comfort for operating personnel during normal operations and during postulated accident conditions. These habitability systems for the main control room include radiation shielding, charcoal filter systems, heating, ventilation, and air-conditioning, storage capacity of food and water, kitchen, sanitary facilities, and fire protection.

A discussion of the main control room systems that control the climatic conditions existing within the main control room is found in Subsection 9.4.1. Shielding considerations are discussed in Chapter 12. Main control room habitability is discussed in Chapter 15.

The main control room habitability systems are designed to meet NRC General Design Criteria 19, which is discussed in Section 3.1.

6.4.1.1 Safety Design Bases

a. The postulated accident conditions are defined, and the extent of simultaneous occurances is discussed, in Chapter 15. The radiologic parameters influencing habitability are the products of release found in the atmosphere surrounding the main control room.

b. The assumptions regarding the sources and amounts of radioactivity that surround the main control room following various design basis accidents are discussed in the applicable sections of Chapter 15.

c. Two accident modes of operation of the main control room environmental control system (MCRECS) are provided to minimize the amount of radioactivity or chlorine entering the main control room following an accident. These modes provide either pressurization or isolation of the main control room, depending on the accident. In both cases, the main control room atmosphere is recirculated through the MCRECS emergency filters. 32 32 28

d. Following postulated design basis accidents, the limitations of main control room temperature, humidity, radioactivity concentrations, and concentrations of chlorine are as follows:

Parameter	Maximum Allowed
Main control room temperature	76 F (dry bulb)
Main control room humidity	50%
Radioactivity concentrations	As stated in 10CFR50, App. A
Concentration of chlorine	1 ppm

e. Noncombustible materials are used in construction and equipment as much as possible. The quantity of combustible material such as paper and other flammable supplies are kept to a minimum. The plant operators receive training in fire fighting and, therefore, someone trained in fire fighting will be on duty at all times.

The fire protection for the main control room is discussed in Subsection 9.5.1. The fire protection for the MCRECS charcoal 28 adsorbers is discussed in Subsection 6.4.1.4.

f. Sufficient storage capacity for a 30-day supply of food and water for two shifts of operators is provided within the boundary of the main control room habitability systems.

g. Kitchen and sanitary facilities are available for two shifts of operators for 30 days within the boundary of the main control room habitability systems.

6.4.1.2 System Description

The main control room environmental control (MCREC) system is shown schematically in Figure 9.4.1. Major system components and significant parameters associated with each component are listed in Tables 6.4-1 and 9.4-1.

The MCREC system supplies heating, ventilation, and air-conditioning for the main control room. The main control room is common for HNP-1 and HNP-2. The principle equipment in the system includes:

a. Three 50-percent capacity air handling units with electric heaters, cooling coils, and fans.

b. Two 100-percent capacity exhaust air fans.

c. Two banks of high-efficiency air filtration units consisting of a prefilter, high-efficiency particulate air (HEPA) filter, an electric heater, a carbon absorber, and a second HEPA filter for emergency treatment of recirculated air or outside supply air. Two filtration-unit booster fans are provided; one for each filtration unit.

6.4.1.2.1 Normal Operation

During normal operation, two of the three air handling units recirculate the main control room air to reduce the requirements for heating and cooling. One of the two main control room exhaust fans is operated to exhaust approximately 2500 cfm to the reactor building vent plenum with the makeup coming from the outside air taken in at the control room ventilation system intake located on the west wall of the control building (see Figure 9.4-1, Sheet 2, 28 for the process flow rates).

The main control room is fully air conditioned and maintained at 76 F (dry bulb), 50 percent relative humidity in summer and 72 F (dry bulb), 50 percent relative humidity during winter. Electric heaters are installed in the supply air ducts to provide heat as required within the main control room. A room thermostat regulates the temperature in the main control room. Subsection 9.4.1 provides an additional discussion concerning temperature and humidity control.

By balancing the exhaust and makeup flow rates, the main control room is normally maintained at a slightly positive pressure with respect to the surrounding turbine building. The outside makeup air and recirculated air pass through a dust filter before reaching the suction of the air handling unit fans. The supply air is cooled or heated by the air handling units as required to maintain the desired temperature. Should one of the two operating air handling units or the operating exhaust fan suffer a fan motor failure, the standby unit fan will automatically start, the associated fan dampers will reposition, and an alarm will be annunciated in the main control room.

6.4.1.2.2 Accident Condition Operation

The main control room HVAC system is designed to assure habitability following any of the design basis radiological accidents or the worst-case chemical release accident.

To provide adequate operator protection in the unlikely event of one of these accidents, two distinct accident modes of operation are included. These modes are referred to as the isolation mode and the pressurization mode.

The mode of system operation following each of the accidents of concern is as follows: 28

a. LOCA	Pressurization mode
b. Fuel-handling accident (FHA)	Pressurization mode
c. Main steam line break (MSLB)	Pressurization mode
d. Control rod drop accident (CRDA)	Pressurization mode
e. Chlorine accident	Isolation mode

32

These accidents are discussed in detail in Chapter 15.

32

The accident modes operate as described below:

Isolation Mode

Upon receipt of a high-chlorine concentration signal from the redundant chlorine detectors located in the control room outside air intake plenum, the following automatic functions will occur (see Figure 9.4-1):

a. Series redundant isolation dampers F011 and F012 close to prevent outside air from bypassing the charcoal filters.

b. Outside air intake isolation damper F016 closes to provide double isolation to the MCRECS charcoal filter trains.

c. Control room restroom exhaust damper F019 and control room kitchen exhaust damper F020 close.

d. Air-handling unit inlet isolation dampers F007A, B, and C from the MCRECS charcoal filter trains open.

e. MCRECS charcoal filter recirculation inlet isolation dampers F014A and B open. 32

f. The operating control room exhaust fan C011A or B is stopped, and the associated isolation damper F018A or B is closed.

g. Booster fan C012A or B, for charcoal filter train D004A or B, starts to establish filtered recirculation of the control room environment. 28

The main control room would now be isolated from the outside air. Approximately 2500 cfm of the main control room atmosphere is recirculated through the charcoal filter train for cleanup. The normal air-handling units will continue to recirculate approximately 28,000 cfm of the control room atmosphere, including the charcoal filter train discharge.

Once initiated, the system will remain in the isolation mode until the high-chlorine condition is no longer detected and the chlorine trip reset switch is manually reset.

Pressurization Mode

The pressurization mode of operation is intended to protect the control room operators in the event of the following design basis radiological accidents:

a. LOCA

b. Fuel-handling accident 32

c. Main steam line break

d. Control rod drop accident

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The following parameters are monitored to provide an initiating signal to the MCREC system to establish the pressurization mode:

a. LOCA signal from Unit 1 or 2

b. Refueling floor high radiation from Unit 1 or 2

c. Main steam line high flow from Unit 1 or 2

d. Main steam line high radiation from Unit 1 or 2

e. Main control room air intake high radiation

Upon receipt of any one of the above initiating signals, the following automatic functions will occur (see Figure 9.4-1):

a. Series redundant isolation dampers F011 and F012 close to prevent outside air from bypassing the charcoal filters.

b. Roll filter bypass isolation damper F015 opens to provide a parallel source of pressurization air from outside. 32

c. Control room restroom exhaust damper F019 and control room kitchen exhaust damper F020 close.

d. Air-handling unit inlet isolation dampers F007A, B, and C from the MCRECS charcoal filter trains open.

e. MCRECS charcoal filter recirculation inlet isolation dampers F014A and B open.

f. The operating control room exhaust fan C011A or B is stopped, and the associated isolation damper F018A or B is closed.

g. MCRECS charcoal filter outside air inlet isolation dampers F013A and B open.

h. Booster fan C012A or B, for charcoal filter train D004A or B, starts to establish filtered recirculation of the control room environment and also pressurization of the control room with filtered outside air.

The main control room would now be positively pressurized with respect to the surrounding turbine building. The 400 cfm (approximately) of outside air taken in at the normal ventilation intake on the west wall of the control building is mixed with approximately 2100 cfm of main control room air and is 28 | 32 passed through the charcoal absorber filter train for removal of airborne radioactivity. The normal air-handling units will continue to recirculate approximately 28,000 cfm. When the control room ventilation system is operating in the pressurization mode, entrance and exit from the control room are 40 only through the double doors (air-lock) that are shown in Figure 3.8-37.

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6.4.1.3 Instrumentation Application

Differential pressure indicators are provided locally to measure the pressure drop across each filter element. The overall pressure drop across each filter train is measured and alarmed in the main control room on high differential pressure.

Each charcoal adsorber is provided with at least two temperature switches. Any one of the temperature switches can actuate an alarm in the main control room when the filter temperature rises above a preset value.

The electric heating coils are controlled by a temperature control set at 150 F. In the recirculation mode the filters are supplied with a maximum of 76 F dry bulb 50 percent RH air. Thus, in this mode, the charcoal adsorber is subject to less than 70 percent RH. Since the mode of operation using outside air through the filters is an operator option and does not have to be used during periods of high outside humidity, the charcoal adsorber can then be operated in an atmosphere of less than 70 percent RH without humidity controls.

Alarm only

Radiation and chlorine monitors are provided in the outside air intake duct. 32
Radiation monitors are also provided in the main control room. The monitors alarm in the main control room upon detection of high-radiation or high-chlorine conditions.

Redundant differential pressure switches are provided which sense the differential pressure between the main control room and the turbine building. These switches alarm in the main control room on low differential pressure when the MCREC system is in the pressurization mode. 28

The instrumentation used to provide the initiating signals for control room pressurization are discussed in Subsections 7.2.2, 7.3.2, and 7.6.3. 32

6.4.1.4 Safety Evaluation

The shielding in the main control room is discussed in Chapter 12. The shielding is designed for continuous occupancy during a LOCA and meets General Design Criterion 19.

The MCREC system is designed with sufficient redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under emergency conditions. Combined, the main control room habitability systems provide maximum safety and comfort for operating personnel during normal and postulated accident conditions. A failure analysis of the MCREC components is shown in Table 6.4-2.

An air lock has been provided for the control room to allow ingress/egress under emergency conditions (see Figure 3.8-37). 32

If under emergency conditions the air temperature near the carbon bed reaches 200 F, the heat detector water-spray control will activate and turn on the deluge valve. At the time water spray comes on, the carbon drying heater control system is deactivated and requires manual resetting. The fan is also

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deactivated and the associated dampers are closed, thus isolating the filter. When conditions permit, the water-spray system may be manually secured.

Radiological and toxicologic consequences of the various accidents described above are discussed in detail in Chapter 15. 28

6.4.1.5 Tests and Inspections

Preoperational and startup testing were performed on this system during the preoperational and startup testing of Unit 1 in 1974. Normal operational surveillance is in accordance with the Unit 1 and Unit 2 Technical Specifications. 44

44

During Unit 2 startup testing, the control room ventilation system will be tested by verifying that on an initiation test signal the system automatically switches into the pressurization mode of operation and maintains the control room at $\geq$0.1 in. w.g. pressure relative to the adjacent turbine building. This test will be performed periodically according to the Technical Specifications. 44 40 44

TABLE 6.4-1

CONTROL ROOM ENVIRONMENTAL CONTROL SYSTEM
COMPONENT DESCRIPTION

A. Filter Trains

Number	2
Size, % capacity (each)	100
Type	Multiple filters for removal of particulates, elemental iodine, organic iodine and bromine from air
capacity, scfm (each)	2500

B. Charcoal Adsorbers (each train)

Number	1 bank
Type	2" tray
Capacity, scfm	2500
Media	Impregnated charcoal
Efficiency, %	95 (min)
Relative humidity, %	70 (max)
Residence time, sec	0.25 (min)
Ignition temperature range, F	662-752
Iodine desorption temperature range, F	250-300
Charcoal iodine loading (30 day accident duration)	2.5 mg max iodine per gm of activated charcoal
Pressure drop, in. wg	0.8
Particle size distribution (mesh)	12 x 20 (Per test method of ASTM 2862)

C. HEPA Filters (each train)

Number	2 banks
Type	High efficiency dry
Capacity, scfm	2500
Media	glass fibre
Efficiency, %	99.97 with 0.3 micron DOP smoke
Pressure drop, clean, in. wg	.6

D. Prefilters (each train)

Number	1 bank
Type	Dry
Capacity, scfm	2500
Media	glass fibre
Efficiency, %	85 NBS dust spot
Pressure drop, clean, in. wg	.3

TABLE 6.4-1 (Cont'd)

E. <u>Heaters (each train)</u>

Number	1
Type	Electric
Rating, watts	526

F. <u>Booster Fans (each train)</u>

Number	1
Size, % capacity	100
Type	Centrifugal
Capacity, scfm	2500
Drive	Direct

G. <u>Air Handling Units are Discussed in Subsection 9.4.1</u>.

H. <u>Exhaust Air Fans are discussed in Subsection 9.4.1</u>.

TABLE 6.4-2

MAIN CONTROL ROOM ENVIRONMENTAL CONTROL SYSTEM
FAILURE ANALYSIS

Component	Malfunction	Comments
A. Booster fan	Failure of fan resulting in reduction of air flow	If the operating fan fails, the resultant reduction of air flow actuates an alarm in the control room, automatically starts the standby booster fan, and opens the standby filter train isolation valves.
B. Electric Heating Coil	Failure of the coil control resulting in constant coil operation	Maximum capacity of the electric treating coil is not sufficient to cause damage
	Failure of the coil or coil control resulting in no heat	The coil is not essential to operation of filter in LOCA emergency recirculation mode.
C. MCREC filter train	Failure resulting in high-differential pressure across the filter train	High differential pressure across the filter train automatically actuates an alarm in the control room. The defective filter train is manually isolated and the standby train is manually placed on service.
	Failure resulting in high radiation at the discharge	The defective filter train is automatically isolated and the redundant filter train is automatically placed into operation upon receiving a high radiation signal.
D. Charcoal adsorber	High temperature in charcoal bed	Temperature sensors are provided in each charcoal bed to alarm in the control room on rising charcoal temperature and to automatically initiate the deluge system.
E. Isolation Damper	Failure to close or failure to close completely	A series redundant damper will provide the required isolation. 28

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TABLE 6.4-2 (Cont'd)

Component	Malufunction	Comments
F. Operational Damper	Failure to open or failure to open completely	A parallel redundant damper provides a flow path for the required operation. 28
G. Air Handling Units and Exhaust Air Fans	All postulated failures	See Table 9.4-2.

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9.4 AIR CONDITIONING, HEATING, COOLING, AND VENTILATION SYSTEMS

9.4.1 MAIN CONTROL ROOM

9.4.1.1 Design Bases

9.4.1.1.1 Safety Design Bases

The main control room environmental control (MCREC) system is designed:

a. With sufficient redundancy and separation of components to provide reliable operation under normal conditions to ensure operation under emergency conditions.

b. To provide purging capability for the removal of radioactive and foreign material from the main control room environment.

9.4.1.1.2 Power Generation Design Bases

The control room air conditioning and filtration system is designed:

a. To provide an environment with controlled temperature and humidity to ensure both the comfort and safety of the operators and the integrity of the main control room components.

b. To minimize the possibility of exhaust air recirculation into the air intake, and

d. To detect and limit the introduction of radioactive material and chlorine into the main control room.

9.4.1.2 System Description

The MCREC system is shown on Figure 9.4-1. Major system components and significant parameters associated with each component are listed in Table 9.4-1. Flow rates for the various modes of operation are shown on Figure 9.4-1, Sheet 2. 18

The main control room is a shared facility divided into two adjacent open areas; one area serves Unit 1, and the other area serves Unit 2. Each area has an independent air-conditioning system consisting of an air-handling unit, condensing unit, electric heating coil, supply and return ducts, and room thermostats. One common air-conditioning system serves as standby for either area.

Normally, two air-conditioning systems operate, i.e., one for each area. If the fan in any operating system fails, an alarm is annunciated in the main control room and the standby system comes on automatically and serves the area affected. The dampers normally isolating the standby system from the operating systems are opened automatically. However, the standby air-conditioning system must be started manually if the failure of the active system is due to the condensing unit or electric heating coil.

There are two filter trains (described in detail in Section 6.4), with two booster fans, to remove any airborne radioactivity from the main control room environment. Each filter assembly is designed to serve both areas. When required, one filter assembly is in use and the other is on standby. If the fan motor in the operating assembly fails, the standby assembly comes on automatically and an alarm is annunciated in the main control room. Except for testing during normal operation, the filter assemblies are not in use.

The main control room is protected from high radiation by pressurization (see Section 6.4). 28 32

Since chlorine is used in the treatment of the plant circulating water, as described in Subsection 10.4.5 of the FSAR, redundant chlorine gas detectors have been located in the main control room intake, which will cause automatic isolation of the main control room in the event that chlorine gas is detected (see Section 6.4). This action results in the recirculation of main control 32
room air similar to that which is caused by a high-radiation signal.

A signal from the chlorine detector located at the onsite liquid chlorine storage area will also initiate an alarm in the main control room, thus indicating abnormal chlorine concentrations at the storage area and simultaneously forewarning operating personnel of a potential chlorine hazard.

When operated as above, the MCREC system will maintain the main control room temperature between 72 and 76 F, dry bulb, with outside air temperature variations from 20 F to 95 F, dry bulb, and will also maintain the main control room relative humidity at equal to or less than 50 percent.

For purging, the air-conditioning systems have the capability of meeting 50-percent supply and 100-percent exhaust air requirements of the control room. The exhaust fan discharge is directed to the reactor building exhaust plenum. The flow rate is approximately 14,000 cfm for both supply and exhaust 39
during purging.

9.4.1.3 Safety Evaluation

A safety evaluation for the MCREC system filters is presented in Subsection 6.4.1.3.

A discussion of main control room habitability during a DBA or chlorine accident is presented in Section 15.1.

A failure analysis of the major system components is presented in Table 9.4-2. A failure analysis for the control room filtration filters and fans is presented in Table 6.4-2. Additional information is provided in the response to question 020.10. 39

9.4.1.4 Tests and Inspections

Preoperational and startup testing were performed on this system during the preoperational and startup testing of Unit 1 in 1974. Normal operational surveillance is in accordance with the Unit 1 and Unit 2 Technical Specifications.

44

TABLE 9.4-1

CONTROL ROOM AIR CONDITIONING AND FILTRATION SYSTEM
COMPONENT DESCRIPTION

A. Air-Handling Units

Number	3
Size, % capacity (each)	50
Type	Horizontal draw through
Capacity, scfm (each)	14,000
Heat-removal capacity, Btu/hr (each)	483,000
Motor	15 hp, 550 Volts/60 Hz/3ϕ

B. Condensing Units

Number	3
Size, % capacity (each)	50
Compressor type	Open, reciprocating
Compressor capacity, tons	40.2
Motor	50 hp, 550 Volts/60 Hz/3ϕ
Condenser cooling water flow, gpm (each)	120
Cooling water source	Plant service water

C. Electric Heating Coils

Number	3
Size, % capacity (each)	50
Rating each, kw	60

D. Exhaust Fans

Number	2
Type	Centrifugal with variable inlet vane control
Capacity, scfm (each)	2550 to 14,000
Motor	7 1/2 hp, 550 Volts/ 60 Hz/3ϕ

E. Booster Fans

Number	2
Type	Centrifugal
Capacity, scfm (each)	2500
Motor	5 hp, 550 Volts/60 Hz/3ϕ

F. Filter Trains are discussed in Section 6.4.

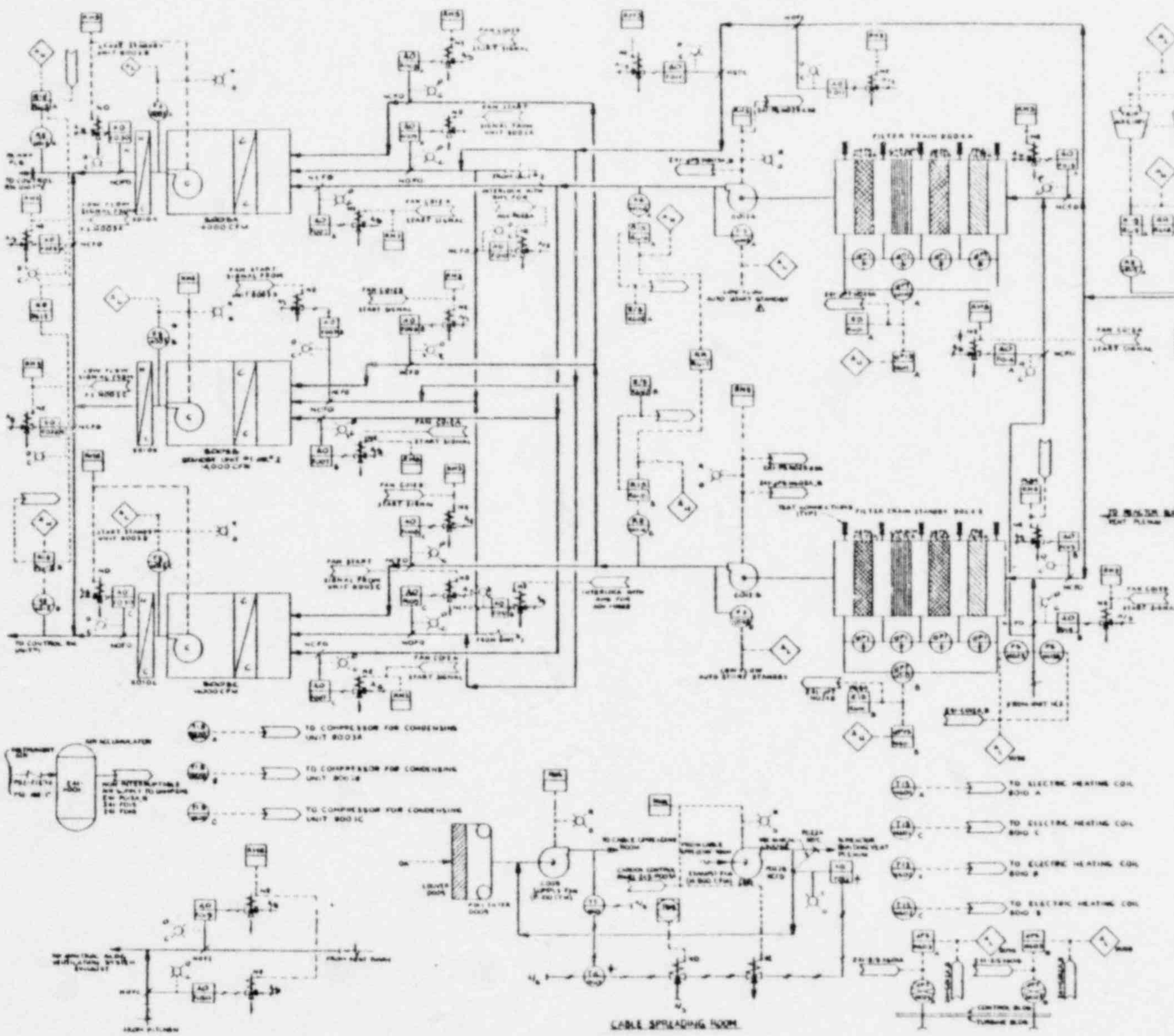
TABLE 9.4-2

CONTROL ROOM HVAC SYSTEMS FAILURE ANALYSIS

Component	Malfunction	Comments
Air-handling unit	Failure of fan motor	Overload protection device trips motor and annunciates in the main control room as well as starting standby air-handling unit. Low-flow switch on fan discharge will also alarm in the main control room.
	Reduced flow	Low-flow switch on fan discharge will alarm in the main control room and automatically start the standby air-handling unit.
	Loss of refrigerating unit	Operators in main control room will detect rise in room temperature and start the standby air-handling unit.
	Loss of heating coils	Operators in main control room will notice drop in room temperature and start the standby air-handling unit.
	Loss of airflow through heating coils	Low-flow switch will automatically shut off power to the coils to prevent burnout.
Booster fan	Motor overload	Overload protection device trips motor. Low-flow switch on fan discharge will alarm in the main control room and automatically start the standby booster fan.
	Reduced flow	Low-flow switch on fan discharge will alarm in the main control room and automatically start the standby booster fan.
Exhaust fan	Motor overload	Overload protection device trips motor. Discharge damper will close to isolate control room. Operator will start standby exhaust fan.

TABLE 9.4-2 (Cont'd)

Component	Malfunction	Comments
	Reduced flow	Operators in the main control room will sense the reduced flow and will start the standby exhaust fan manually.
Dampers	Failure of dampers	Dampers connecting the charcoal filters to the outside fail open on loss of electrical power or operating air. This is the desired position for main control room pressurization. The dampers are provided with seismic Category I air accumulators 32 and receive power from the emergency diesels to ensure that they can be closed if isolation is required. Double damper isolation is provided with all other isolation dampers failing closed.
		Dampers in the air-handling units fail open, thus ensuring that operation of the air-handling units is not restricted.
Power source	Loss of offsite power	The HVAC equipment in the main control room is shifted to emergency diesel power.
Filter trains	All postulated failures	See Table 6.4-2.



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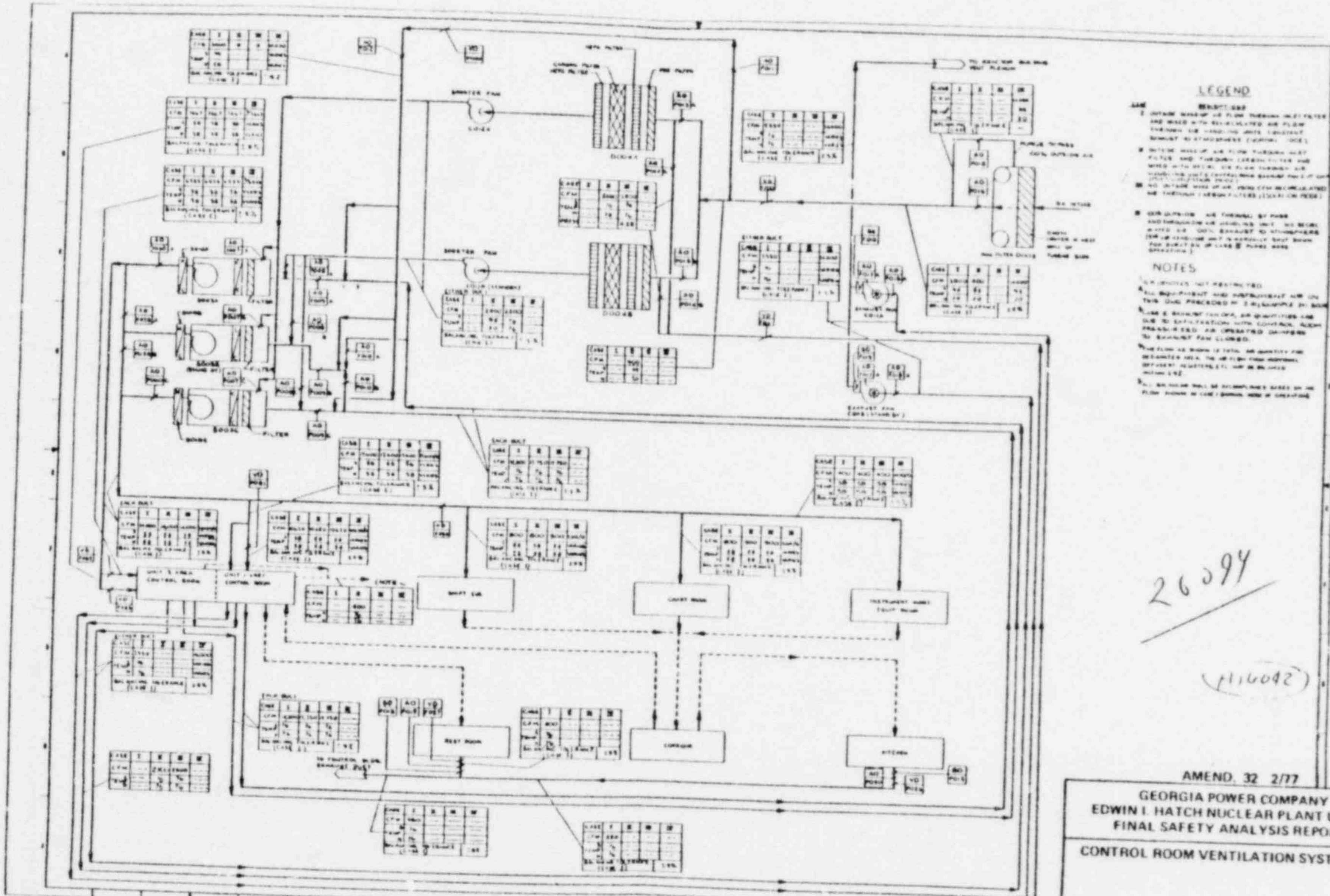
GEORGIA POWER COMPANY
EDWIN I. HATCH NUCLEAR PLANT UNIT 2
FINAL SAFETY ANALYSIS REPORT

CONTROL ROOM VENTILATION
SYSTEM P&ID

FIGURE 9.4-1 SHEET 1



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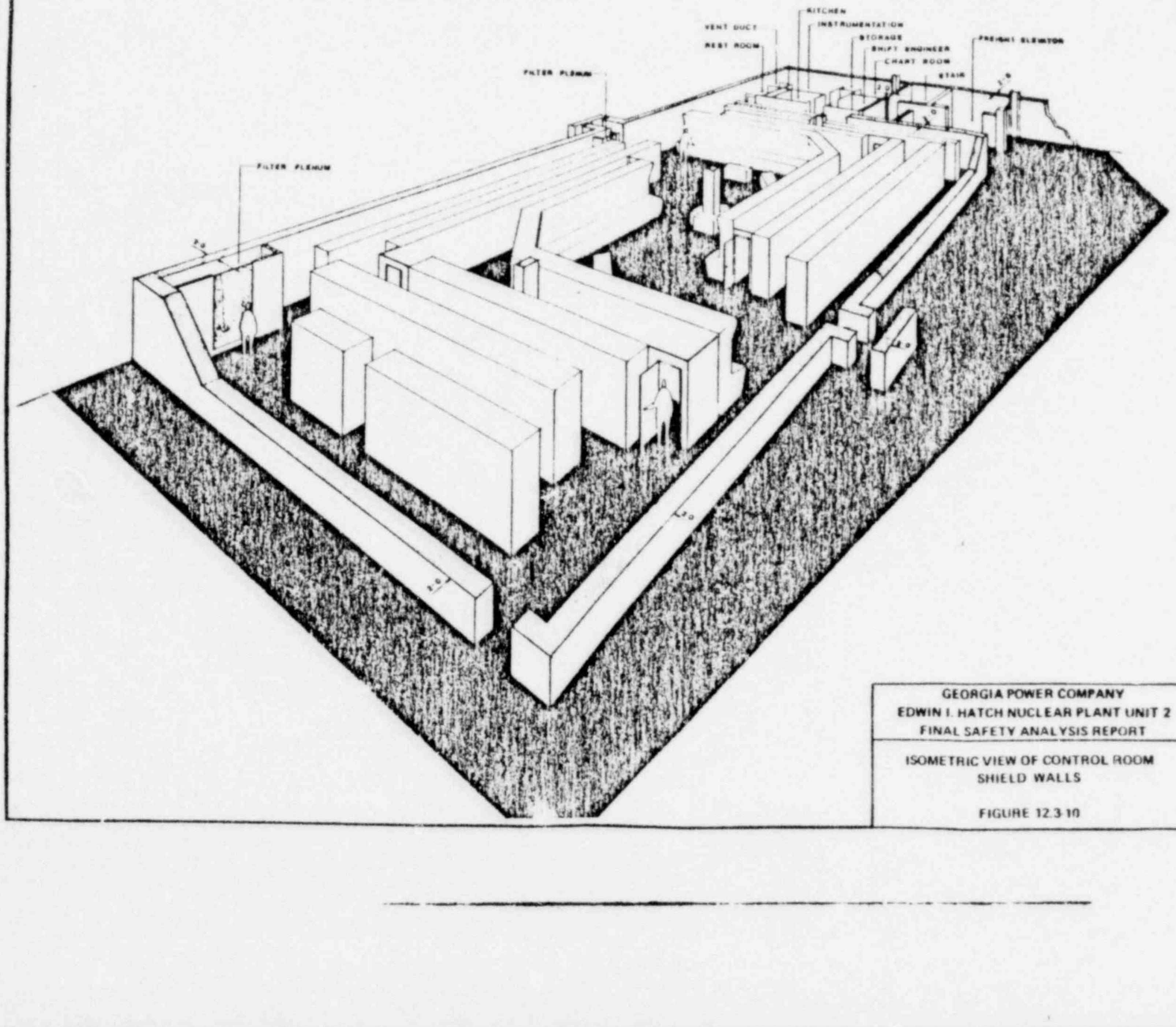
FINAL SAFETY ANALYSIS REPORT

CONTROL ROOM VENTILATION SYSTEM PFD

FIGURE 9.4-1 SHEET 2

POOR ORIGINAL



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FINAL SAFETY ANALYSIS REPORT

ISOMETRIC VIEW OF CONTROL ROOM
SHIELD WALLS

FIGURE 12.3-10

POOR ORIGINAL

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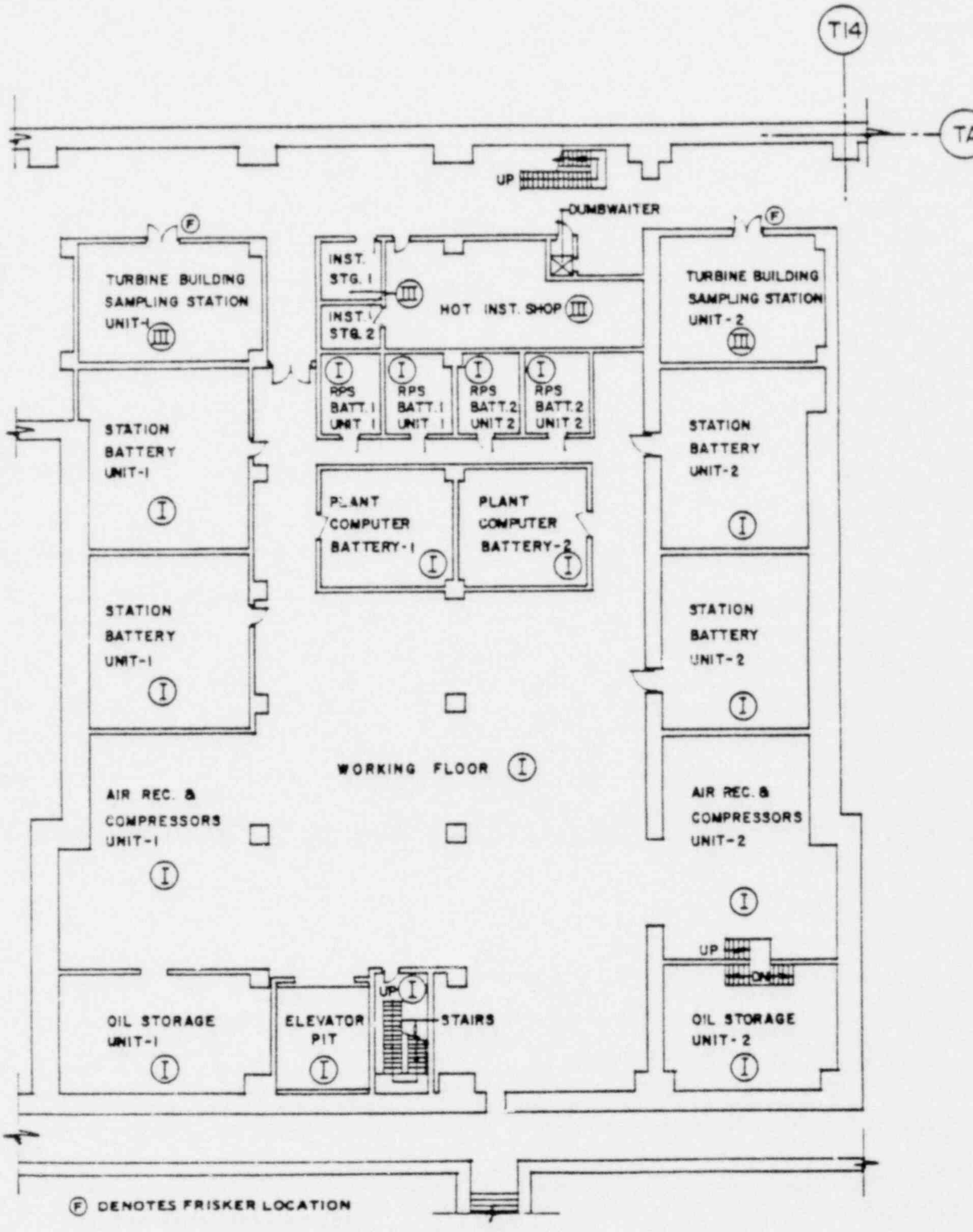

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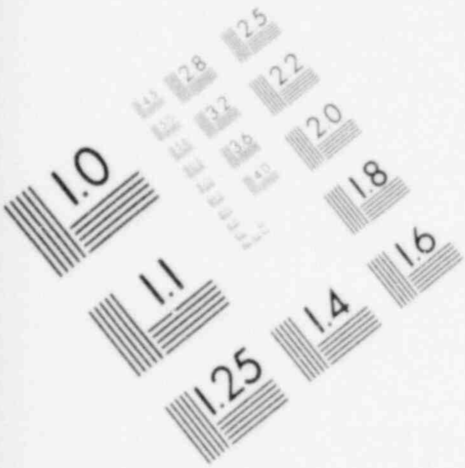
GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	SHIELDING AND ACCESS CONTROL - CONTROL ROOM EL. 112' FIGURE 12.3-11

IMAGE EVALUATION
TEST TARGET (MT-3)

6″



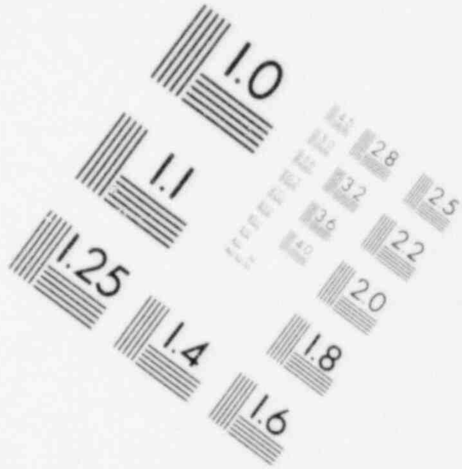
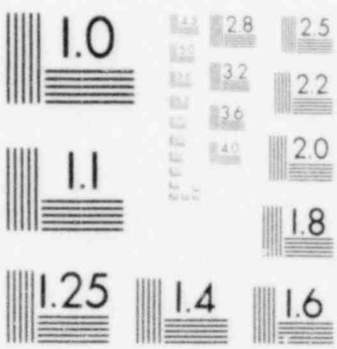


IMAGE EVALUATION TEST TARGET (MT-3)



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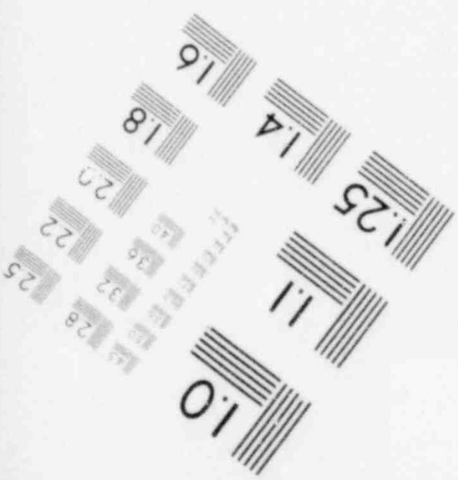

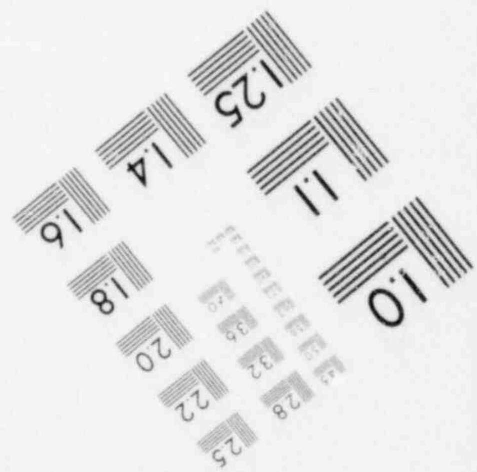

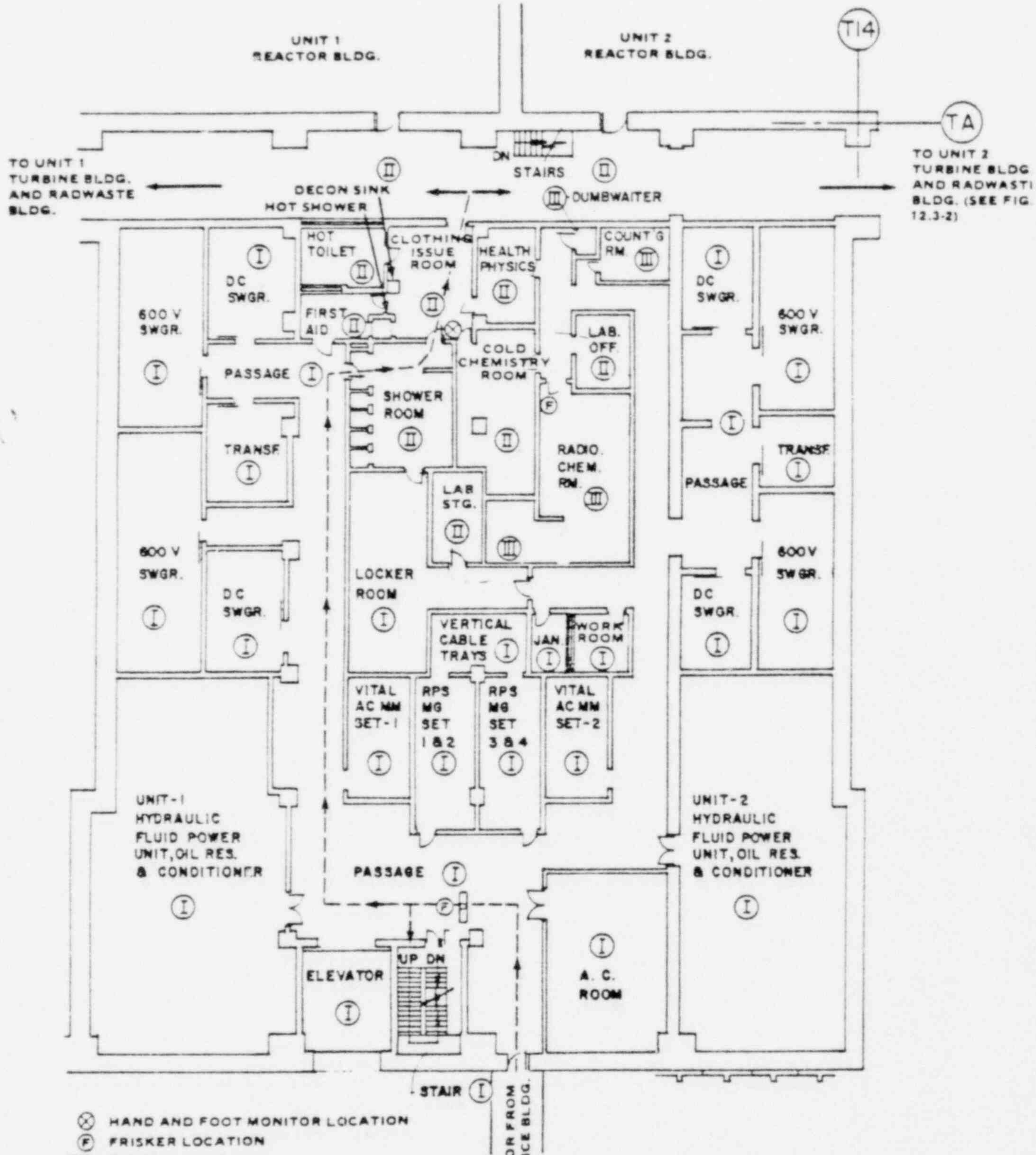

⊗ HAND AND FOOT MONITOR LOCATION

Ⓕ FRISKER LOCATION

▭ PORTAL MONITOR

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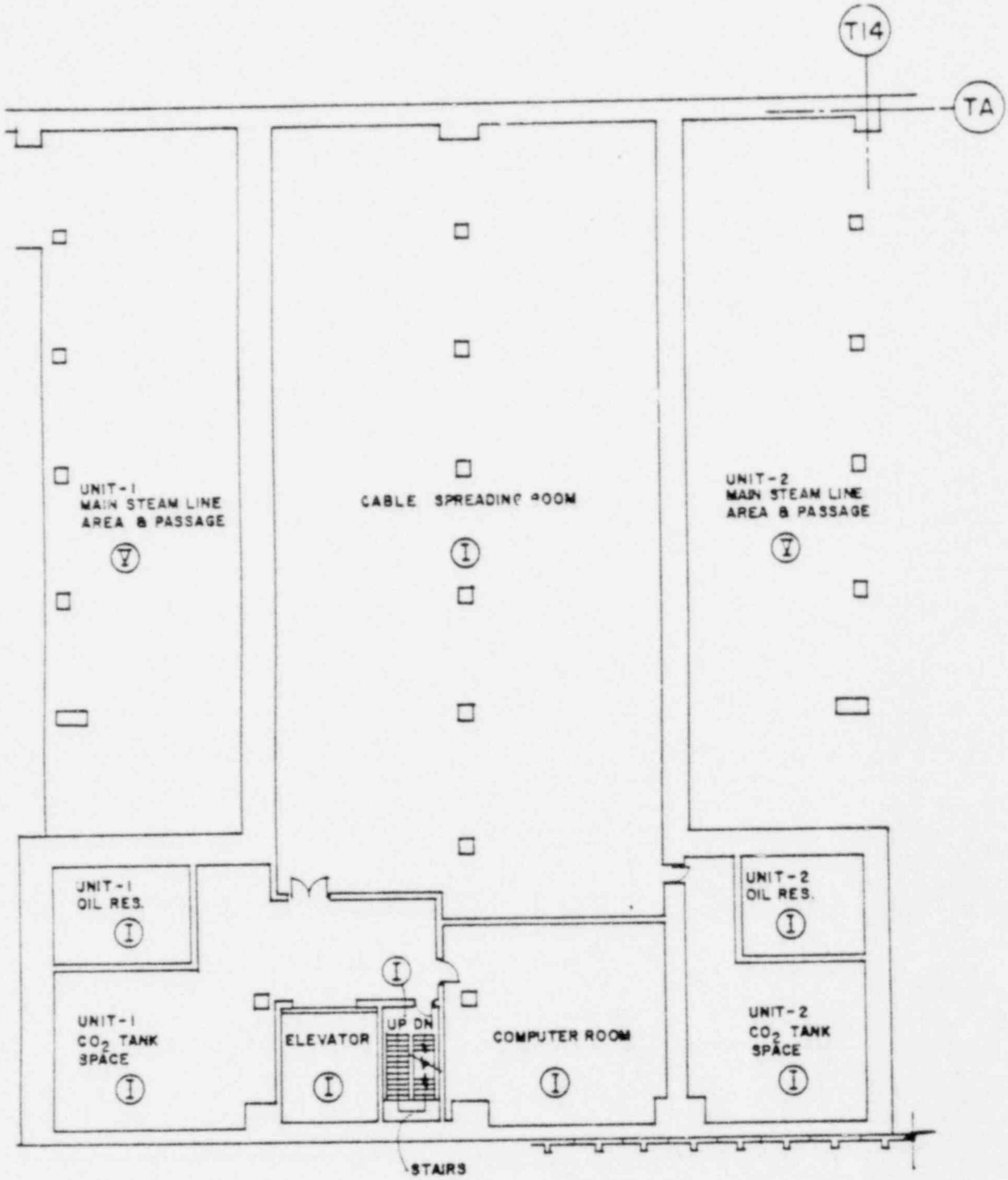
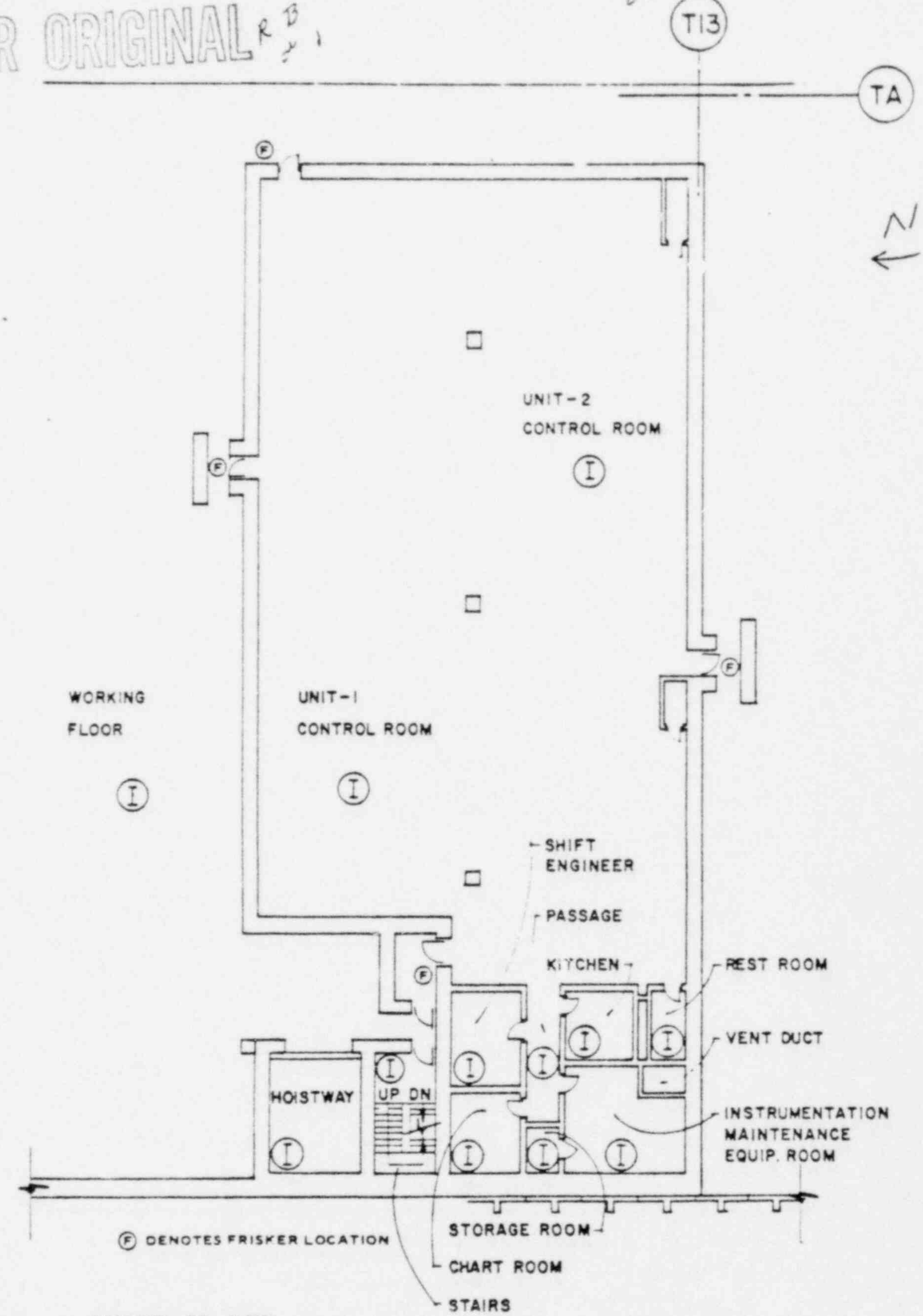
GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	SHIELDING AND ACCESS CONTROL - CONTROL BLDG. EL. 130' FIGURE 12.3-12



GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	SHIELDING AND ACCESS CONTROL - CONTROL ROOM EL. 147' FIGURE 12.3-13

POOR ORIGINAL



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GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	SHIELDING AND ACCESS CONTROL - CONTROL ROOM EL. 164' FIGURE 12.3-14

z. Regulatory Specialist

The regulatory specialist is directly responsible to the superintendent of plant engineering services for coordinating the overall fire protection program at the plant. In addition, he serves as OSHA specialist to assure compliance with the federal OSHA regulations and as plant safety specialist coordinating all plant safety functions. 42

The succession to responsibility for overall operation of the plant in the event of absences, incapacitation of personnel, or other emergencies shall be as follows:

a. Plant Manager 22

b. Assistant Plant Manager

c. Superintendent of Operations

d. Superintendent of Plant Engineering Services 29

e. Operations Supervisor

f. Shift Foreman

The Shift Foreman is responsible for the actual unit operation during his assigned shift, as indicated in Subsection 13.1.2.3. In the event he is incapacitated, the Senior Plant Operator will assume his responsibilities and authorities until a licensed senior reactor operator is available. 29 35

13.1.2.3 Shift Crew Composition

HNP-1 and HNP-2 share a common control room. The ten-man operating crew for the two units, which includes six licensed operators, provides adequate control of plant operation during normal operation and sufficient manning to handle emergency conditions. When either or both units are in the cold shutdown condition, it will not be necessary to have both a Plant Operator and an Assistant Plant Operator manning each unit. Figure 13.1-7 indicates shift manning under all conditions. Each reactor unit is designed for one-man operation from the control room. Systems essential to power generation that require continuous operation are automatic and have control room supervision. Process systems operate automatically following manual starting. Such systems have alarms to indicate malfunctions and remote shutdown capability to minimize operator action beyond initial lineup and supervision of operation. Figure 13.1-6 indicates which personnel will meet Nuclear Regulatory Commission license requirements. 35

Each unit has all required safety system indications and control in the control room so that in an emergency situation it can be shut down safely by any of the licensed operators on shift. Additionally, automatic and redundant reactor protection and engineered safety features ensure safe plant shutdown without operator action under the most severe accident conditions.

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Shift operating personnel are trained and qualified to implement radiation protection procedures, including routing and special radiation surveys using portable radiation detectors, use of protective barriers and signs, use of protective clothing and breathing apparatus, performance of contamination surveys, checks on radiation monitors, and limits of exposure rates and accumulated dose.

The initial operations personnel have extensive training and/or experience in nuclear and conventional power operation and will be engaged in a continual retraining program to ensure the continued safe and efficient operation of the plant. Before assuming their responsibilities, replacement personnel will have the same minimum qualifications as the initial operations personnel.

During periods of increased activity such as refueling, startup after a shutdown of long duration, or special testing, additional operating personnel will be assigned to augment the normal crew as required. Similarly, the shift organization during initial testing and startup is basically the same as the normal operating organization but is supplemented as necessary during this period. Georgia Power Company General Office personnel will be available to provide technical direction and assistance during this period.

A licensed operator (Reactor Operator or Senior Reactor Operator) will be in
the control room for each unit in which there is nuclear fuel in the reactor.
A Senior Reactor Operator (SRO) will be onsite for each unit in which nuclear
fuel is in the reactor. Two licensed operators per unit will be in the con- 29
trol room for each reactor which is not in a cold shutdown condition (see
Figure 13.1-7).

One member of each shift crew will be qualified and designated to implement radiation control procedures. In the event that any member of a minimum shift crew is absent or incapacitated due to illness or injury, a qualified replacement will be designated to report onsite immediately.

A Senior Reactor Operator with no other concurrent operational duties will directly supervise irradiated fuel handling and transfer activities and all fuel assembly transfers to or from the reactor vessel.

13.1.3. QUALIFICATION REQUIREMENTS FOR NUCLEAR PLANT PERSONNEL

The following qualification requirements will be met or exceeded by the minimum plant operating staff. There may be instances where additional servicemen or technicians will be used to supplement the normal staff and do not meet these qualifications. The minimum operating staff will be required to obtain and maintain qualification standards equal to or better than those specified in ANSI N18.1-1971, Standard for Selection and Training of Personnel for Nuclear Power Plants. The personnel selection and training program ensures fulfillment of these qualification requirements and also satisfies the Commission's Regulatory Guide 1.8 (March 1971), Personnel Selection and Training. Specific minimum qualifications for all those employees identified
in Subsection 13.1.2 are given below. The minimum number of individuals in
each classification is given in Figure 13.1-6. Minimum qualification 22
requirements need be met only by the number so indicated.

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15.1.42 CONTROL ROOM UNINHABITABILITY

The main control room (MCR) is continuously occupied by qualified operating personnel. As discussed in Section 6.4, the MCR is habitable under anticipated operational occurrences as well as design basis accidents.

15.1.42.1 Identification of Causes

15.1.42.1.1 High Radiation

The main control room shielding and HVAC system provide a design that ensures control room habitability throughout any design basis radiological accident. The HVAC system is designed to shift automatically to the pressurization mode to prevent infiltration of contaminated air into the control room should any one of a number of high-radiation signals be received (see Section 6.4 for details on the initiating parameters). In the pressurization mode, the control room is positively pressurized with respect to the surrounding turbine building by taking in approximately 400 cfm of outside air through one of the redundant control room charcoal filter trains. The control room normal air-handling units remain operable during accident conditions to provide air conditioning. 32 28

The operation of the main control room HVAC system is discussed in more detail in Section 6.4 and Subsection 9.4.1.

The radiological doses to main control room personnel as a result of the various design basis accidents discussed in Subsections 15.1.38 through 15.1.41 are summarized in Table 15.1-44. In all cases, the doses are within the limits of 10CFR50, Appendix A, General Design Criterion 19. 32

15.1.42.1.2 Failure of the Main Control Room Environmental Control (MCREC) System

The MCREC system, described in Subsection 9.4.1, is composed of three independent, physically isolated, 50 percent capacity subsystems. The MCREC system is designed in accordance with seismic Category I requirements and is designed to retain full design capacity despite a single active failure.

15.1.42.1.3 Fires in the Main Control Room

The MCR is designed and operated under requirements to minimize the likelihood that a fire might originate in the MCR. Severe limitations are placed on combustible materials in the MCR. Thermal and electric insulation has been chosen to minimize flame spread, smoke, and noxious gas production (refer to Subsection 9.5.1). Therefore, it is extremely improbable that a fire could spread or compromise MCR habitability.

The MCR fire protection system is described in Subsection 9.5.1. It is composed of detectors and an assortment of dry chemical and carbon dioxide extinguishers. The MCR habitability system provides for rapid smoke clearing through the ventilation system. Self-contained breathing devices are available should they be required due to smoke conditions. 39

Even in the unlikely event of an Underwriters Laboratory Class A fire, the MCR operators can quickly extinguish the fire and main control room evacuation should not be necessary. The results of an analysis that indicates that MCR personnel will not be adversely affected by the toxic fumes of the fire extinguishing agents and the products of combustion due to a fire in the MCR are provided in the response to question 020.13. 39

The MCR smoke detection system is a network of 36 ionization detectors which form a shared system covering both the Unit 1 and 2 areas of the control room. 36
MCR smoke detection is effected by these detectors which actuate an audiovisual alarm on the Unit 1 MCR panel H11-P653 and register supervisory alarm signals on the audiovisual fire-annunciator panel in the Unit 1 MCR.

15.1.42.1.4 Fires External to the Main Control Room

The MCR occupies one floor of the control building. The adjacent floors, both above and below, are isolated by fire barriers. The ventilation system for the MCR is isolated from and independent of the ventilation system for the 36
cable spreading room. Cable and other penetrations into the MCR incorporate smoke and fire stops. The fire protection and suppression system for the cable spreading room is described in Subsection 9.5.1 and is designed to confine and extinguish fires originating in the cable spreading room. The other 36
floors of the control building also incorporate provisions for fire suppression and control as described in Subsection 9.5.1.

A fire external to the MCR might introduce smoke and heat into the MCR through the MCREC system outside air intake. There is no smoke detector in the outside air intake duct. However, upon smoke reaching the main control room, the operator would become aware and would manually isolate the main control room. The MCR remains habitable by the full operating crew in the isolation mode for at least 200 hours, an interval limited by the buildup of carbon dioxide. Therefore, it is extremely improbable that a fire external to the MCR will require MCR evacuation.

15.1.42.1.5 Pipe Rupture in the Fire Protection System

The carbon dioxide storage unit, located outside the cable spreading room, is designed for a pressure of 363 psi. The working pressure is 300 psi. The storage unit is manufactured and tested in compliance with ASME Code for Unfired Pressure Vessels. Safety/relief valves (2) are set at 357 psi. An audible alarm is set to sound at 325 psi. This unit is designed to comply with part 1910-Occupational Safety and Health Standards. The storage unit is located inside the control building on floor elevation 147' and contains 26,000 lbs. of CO_2, the total energy released in an isentropic expansion of liquid CO_2 to atmospheric pressure is 3.15×10^8 ft. lbs. The storage unit is separated from any safety related equipment by a walled enclosure, is constructed of steel with a steel outer container and insulation between and has a minimum shell thickness of 31/32 in. and minimum head thickness of 13/16 in. The design temperature limits are -20 F to 650 F with a normal operating temperature of 0 F. Additionally, the unit is hydrostatically tested at 550 psi. Pressure is controlled by a refrigeration unit, and over pressurization is prevented by two safety/relief valves. The possibility of an explosion is not seen since CO_2 is a stable compound. For these reasons no mechanisms of vessel rupture are postulated and only a break of the largest line (6"), leading from the unit, is considered. The calculated overturning moment is 1.7×10^6 in.-lb. Since it would take an overturning moment in excess of 10^7 in.-lb. to overturn the unit, it is concluded that a break of the largest line could not move or overturn it.

A pressure transient analysis was performed for the case of the 6" line rupture. The 6" line is a seven (7') foot standpipe which extends to near

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the bottom of the tank. Following the postulated break, two phase flow will result with a maximum estimated blowdown rate of 500 lb/sec. At the pipe exit it is conservatively extimated that 50 percent of the liquid CO_2 has flashed to gas.

The CO_2 tank room has an estimated free volume of 21,000 $ft.^3$ and the limiting structural elements (concrete block walls) have a design basis of 50 pounds per square foot (psf) differential pressure, although these walls are estimated to be capable of withstanding about two to four times this pressure differential. The CO_2 tank room is separated from the cable spreading room by a wall with normally-closed fire doors. Assuming that the blowdown rate is constant until the tank empties, the transient analysis indicated a requirement of 13 ft^2 of vent area out of the CO_2 tank room in order to limit the differential pressure to less than 50 psf. The required vent area will be provided in the ceiling of the tank room which leads to the HNP-1 turbine deck. The effectively infinite volume of the turbine deck precludes a pressure problem. Furthermore, the separation of the CO_2 tank room from the main control room and the turbine deck from the control room is such that no CO_2 will reach the control room. The control room air intake is located on the west wall of the turbine building and the turbine building ventilation exhaust is through the reactor building vent stack east of the turbine building.

In the event of a fire in the cable spreading room and concurrent discharge of 97% liquid CO_2 at a rate of 44 lb/sec. (system design flow), the current ventilation system exhaust ducting would provide enough vent area to maintain the differential pressure below 50 psf. The cable duct seals leading to the main control room are designed to withstand pressure substantially greater than the resultant pressure, and the cable spreading room has a separate ventilation system, thus precluding the entrance of CO_2 into the main control room.

15.1.42.1.6 Hazardous Chemical Release

Chlorine is the only hazardous chemical stored onsite. Chlorine is utilized to treat the circulating water system and service water system. The chlorine is stored in one-ton containers in a 64' x 48' building located near the circulating water flume as shown in Figure 15.1-30. A maximum of two one-ton | 28
containers are connected to the discharge header at one time. The liquid chlorine is vaporized by a skid-mounted vaporizer and piped to the treatment points. Gaseous chlorine is piped to the intake structure and a chlorine solution is piped to the circulating water system as shown in Figure 15.1-31. | 28

a. The maximum inventory of chlorine that will be on hand at any one time will be sixteen one-ton containers.

b. One ton cylinders will be used for the storage of liquid chlorine (Cl_2) on site. The frequency of delivery will of course depend on demand; however, the maximum demand has been determined to be 1200 lb/day; therefore, based on the ability of a truck to haul 12 one-ton cylinders, one delivery per week by truck would suffice.

c. Transportation of chlorine to the site will be handled by a licensed carrier in accordance with required DOT (and/or ICC) regulations. The plant personnel employed for handling and storage of chlorine will be trained in these practices (e.g., replacement of a defective header valve). Storage, handling, and utilization systems are of proven design, having been used successfully over the years at Georgia Power Company generating facilities. The containers are of welded steel construction conforming to ICC specifications and regulations.

The chlorine system has been designed to eliminate the potential fire sources. The building roof and exterior walls are of metal construction and the floor and interior walls are concrete. The container storage room contains only the container racks and an electric hoist. The skid-mounted vaporizer has no combustible material. Additionally, chlorine gas or liquid is non-explosive and non-flammable. No flammable materials will be stored in the building, thus, fire hazards have been minimized in design. The chlorine building is monitored and an alarm is annunciated locally in case of chlorine leakage.

An overhead electric hoist is used to convey the one-ton containers from a transport truck into the chlorine building and from one location in the building to another. A special lifting beam grips the crimped container ends for positive coupling. This two-ton capacity hoist has a design safety margin of five. The chlorine containers are supported just off the floor to minimize the lifting height for moving containers in the building. Thus, the potential for a handling accident is minimized by utilizing a higher capacity hoist and low container supports.

In order to assure that the main control room (MCR) is continuously habitable under adverse combinations of meteorological conditions and an accidental chlorine release, a conservative licensing basis evaluation of chlorine concentrations in the MCR atmosphere following such an accident is presented here. Appropriate assumptions from Regulatory Guide 1.78 (June, 1974), are incorporated in the analysis.

Redundant chlorine detectors are located at the onsite liquid chlorine storage area, which will generate an alarm signal in the MCR in the event of a chlorine accident, thus indicating abnormal airborne chlorine concentrations at the storage area and simultaneously forewarning the control room personnel of a potential chlorine hazard.

The air intake ducting to the MCR is fitted with chlorine monitors which have a sensitivity of 1ppm of chlorine (by volume) in air for detection. The monitor response times are specified below.

Chlorine Concentration at the Monitor (ppm)	Monitor Response Time for Generation of Alarm Signal (sec)
1	< 20
2	< 10
5	< 5

It is assumed that during the postulated chlorine accident in the chlorine building, 2 tons of chlorine are released. This is the maximum amount of chlorine contained in 2 cylinders headered together at one time. Twenty-five percent of the total release is assumed to flash to gas which is instantly released as a puff from the building. The remaining 75 percent is assumed to form a pool of area 149 m^2 (area of the chlorine storage room floor) from where it evaporates to the atmosphere over an extended period of time. It is estimated that with five percentile site meteorology the chlorine concentration (caused from initial puff release) at the monitor at the control room air intake will rise from 1 ppm to 5 ppm in less than 3 seconds. Since the response time of the chlorine monitors at the intake is less than 5 seconds at 5 ppm concentration, an effective monitor response time of 7 seconds is used in the analysis. At this time an alarm signal of abnormal chlorine concentration at the air intake will be received in the control room. The two isolation valves in the air-intake ducting, located downstream of the chlorine monitors, will automatically close within 5 seconds after generation of the alarm signal. The transport time from the monitor location to the first isolation valve is 7 seconds at the air-intake flow rate of 3000 cfm. Therefore, only that amount of chlorine which passes the monitor up to 2 seconds prior to the alarm signal will make its way into the MCR from the air-intake before the closure of the isolation valves. Simultaneous with the closure of the isolation valves and automatically, the MCR normal ventilation supply and exhaust fans are shut down and recirculation of the control room air is initiated.

After the closure of the isolation valves no additional chlorine will be added to the MCR from the air-intake location. However, an inleakage of 60 cfm of contaminated air from the turbine building atmosphere into the isolated MCR is used in the analysis. The 60 cfm inleakage is the calculated rate of infiltration into the MCR through the door-seals assuming a pressure difference of 1/8" W.G. between the turbine building atmosphere and the MCR. Because of dilution of chlorine in the combined free volume of the turbine buildings of Unit 1 and Unit 2 before its infiltration into MCR, the chlorine concentration in the MCR is calculated to be low.

15.1.42.1.6.1 Assumptions and Parameters

The following assumptions and parameters were used in the chlorine analyses:

a. Two tons of chlorine are released accidentally in the chlorine building, of which 25 percent is instantly released to the environment as a puff, and the remaining 75 percent of the chlorine is spilled over the floor of the storage room from where it is continuously released to the environment. (Floor area = 149 m^2). The roof is assumed to have burst off during the accident.

b. Onsite five percentile meteorology is Pasquill's stability Class F with wind speed = 0.62 m/sec

c. The wind blows directly from the chlorine storage area toward the MCR air-intake.

d. The distance from the location of the release to the MCR air-intake = 700 ft (214 m)

e. The cross sectional area of the turbine building complex = 5549 m^2.

f. MCR net free volume = 93,500 ft^3 (2648 m^3).

g. MCR ventilation air intake rate = 3,000 cfm (1.41 m^3/sec).

h. The MCR is isolated by the alarm signal from the chlorine monitors located at the air-intake as described earlier and remains isolated throughout the duration of the accident.

i. After isolation of the MCR, the only way chlorine gets into the main control room is by inleakage of 60 cfm (0.0283 m^3/sec) of contaminated air from the turbine building atmosphere assuming 1/8" W.G. of pressure difference.

j. The flow rate of outside contaminated air into the turbine building is 55,000 cfm (25.95 m^3/sec) of which 30,000 cfm is into the turbine building of Unit 1 and 25,000 cfm is into the turbine building of Unit 2.

k. Chlorine drawn into the turbine building mixes with the combined free volume of the two interconnected turbine buildings. The net combined free volume = 9 x 10^6 ft^3 (2.548 x 10^5 m^3).

l. Three alternative cases of atmospheric dilution models for calculation of chlorine concentrations in the MCR are used. In all cases the release is considered to be at ground level in the chlorine storage area.

   1. <u>Case A</u> Turbine building complex wake effect is taken into consideration for dilution at the MCR intake location. The MCR air intake location is treated as a ground level receptor.

   2. <u>Case B</u> No credit is taken for turbine building complex wake effect. The MCR air intake location is treated as a ground level receptor.

   3. <u>Case C</u> No credit is taken for turbine building-complex wake effect. The MCR air intake location is treated as an elevated receptor: elevation above ground = 50 ft ($\approx$ 15 m).

m. Diffusion equations:

1. For ground level puff release the equation is the same as given in Regulatory Guide 1.78 (June, 1974) Appendix B.

2. For ground level continuous release the equation is the standard Gaussian plume diffusion equation.

3. For the building wake effect the diffusion equation is

$$X = \frac{KQ}{AV}$$

where X = concentration, g/m^3

K = concentration coefficient ($K = 2$ is used)

A = projected area of the structure, m^2

V = wind speed, m/sec

Q = release rate of chlorine at an interstage line of building wake and open atmosphere, g/sec

15.1.42.1.6.2 Results and Discussion

Graphical representations of chlorine concentrations (vs. time) inside the MCR are given in Figures 15.1-32 through 15.1-34 for the cases A, B, and C of assumption 1. As can be seen from the graphs, the chlorine concentration in the MCR at 2 minutes after the alarm signal is: |28

.039 ppm for case A
.551 ppm for case B
.028 ppm for case C

For each of the cases A, B, C, there is no peak in the chlorine concentration in the MCR within the 2 minutes time under discussion. The above stated concentrations are well below 15 ppm which is the toxicity limit for chlorine for human tolerance for a period of exposure of 30 minutes. The two-minute time following the alarm signal is considered sufficient time for a trained operator to put a self-contained breathing apparatus into operation.

Self-contained breathing apparatus for use over extended periods of time (at least 6 hours) will be readily available to the main control room personnel. Sufficient breathing apparatus is provided to allow one spare per every three required.

TABLE 15.1-44

MAIN CONTROL ROOM POST-ACCIDENT DOSES TO AN OPERATOR

Accident	Dose (rem) After Exposure of		
	8 Hours	24 Hours	30 Days
1. LOCA			
Thyroid	1.00E+01	1.70E+01	2.88E+01
β-skin	1.29E+00	2.00E+00	2.69E+00
T.B. Gamma	1.80E-01	2.63E-01	3.70E-01
2. Fuel-handling Accident			
Thyroid	2.93E-02	2.93E-02	NA(1)
β-skin	4.43E-02	4.98E-02	NA(1)
T.B. Gamma	4.49E-03	5.03E-03	NA(1)
3. Control Rod Drop Accident			
Thyroid	1.82E-02	3.78E-02	1.09E-01
β-skin	3.99E-02	7.88E-02	1.22E-01
T.B. Gamma	5.56E-03	1.01E-02	1.44E-02
4. Main Steam Line Break Accident			
Thyroid	1.38E+00(2)	NA(2)	NA(2)
β-skin	2.51E-03(2)	NA(2)	NA(2)
T.B. Gamma	6.67E-04(2)	NA(2)	NA(2)

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(1) Duration of the accident is 24 hours.
(2) Duration of the accident is 2 hours.

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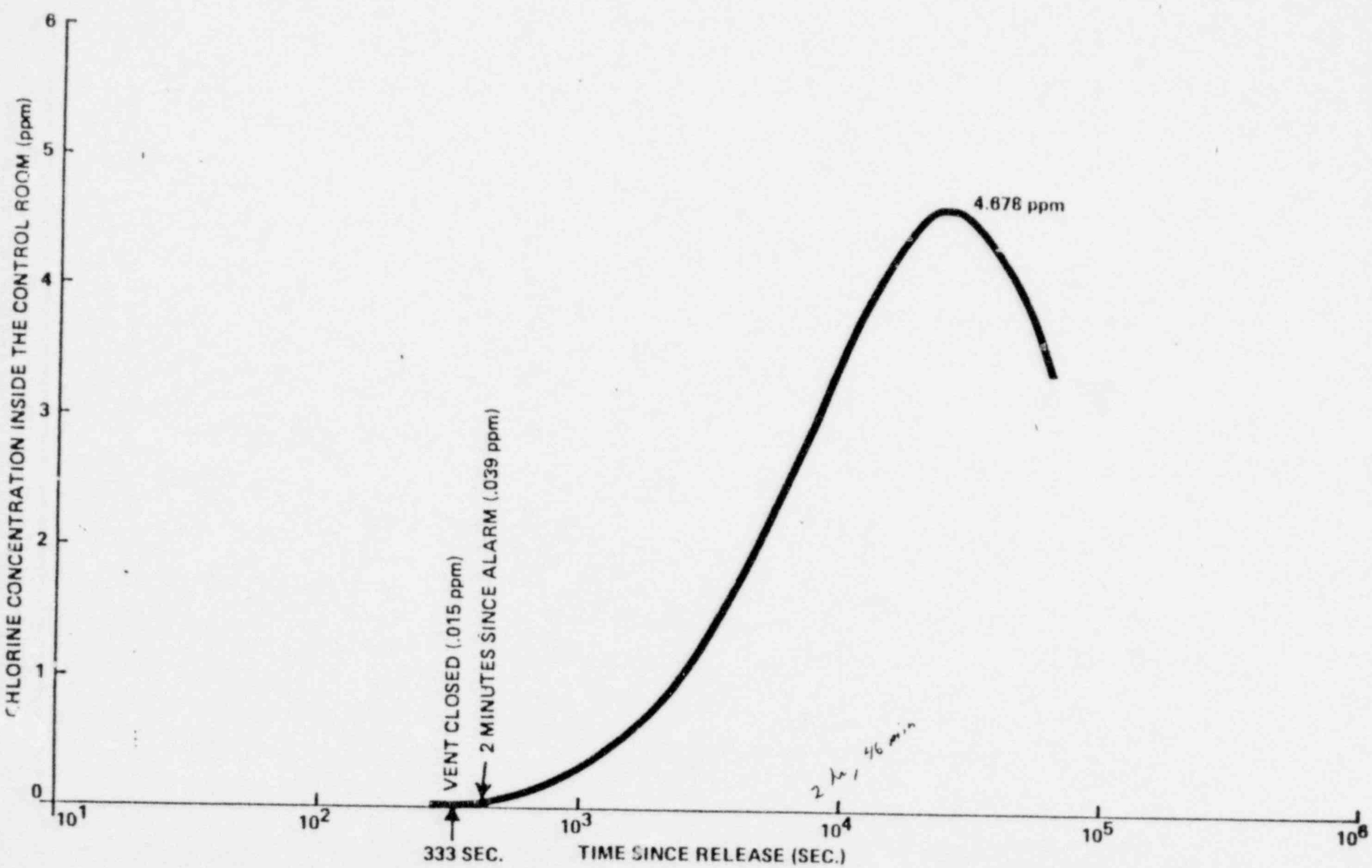

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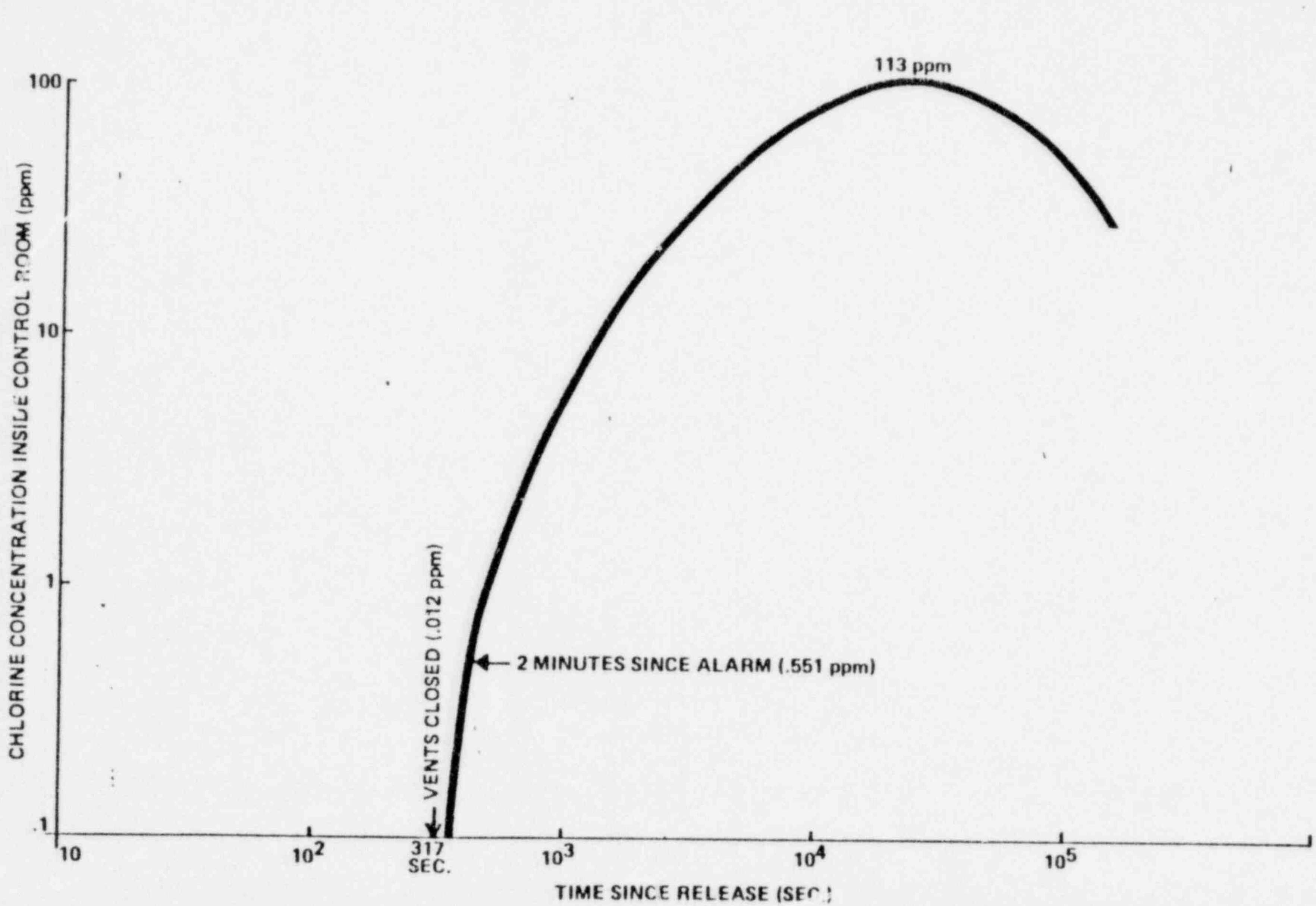
GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	CHLORINE CONCENTRATION INSIDE CONTROL ROOM VS TIME SINCE RELEASE - CASE A FIGURE 15.1-32



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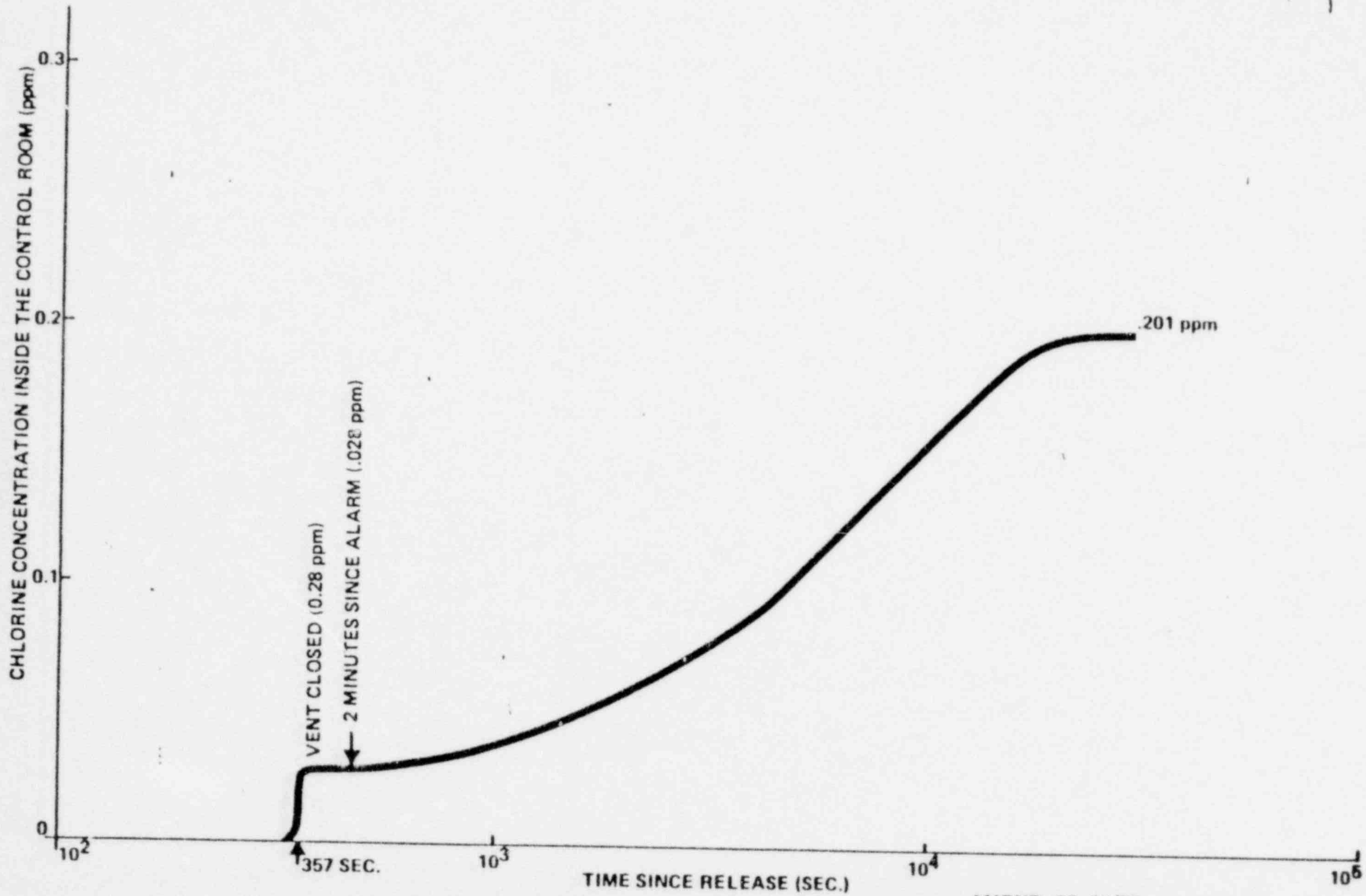
GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	CHLORINE CONCENTRATION INSIDE CONTROL ROOM VS TIME SINCE RELEASE - CASE B FIGURE 15.1-33



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GEORGIA POWER COMPANY EDWIN I. HATCH NUCLEAR PLANT UNIT 2 FINAL SAFETY ANALYSIS REPORT	CHLORINE CONCENTRATION INSIDE CONTROL ROOM VS TIME SINCE RELEASE - CASE C FIGURE 15.1-34

2.2 NEARBY INDUSTRIAL, TRANSPORTATION, AND MILITARY FACILITIES

2.2.1 LOCATIONS AND ROUTES

Figure 2.2-1 is a map of the site area showing the location of transportation routes and a pipeline.

2.2.2 DESCRIPTIONS

2.2.2.1 Description of Facilities

Within a 5-mile radius of HNP-2, there are no manufacturing plants, chemical plants, refineries, storage facilities, mining and quarrying operations, military bases, missile sites, transportation facilities, oil and gas wells, or underground gas storage facilities. Also, there are no known military firing or bombing ranges or aircraft low-level flight holding or landing patterns near the site area. There is truck traffic on U. S. Highway No. 1, which passes about 3,500 feet west of the plant buildings. The nearest railroad passes about 10 miles southwest of the site. A spur line has been constructed to the site.

2.2.2.2 Description of Products and Materials

The cargo most frequently transported near the plant would be longleaf and slash pine logs harvested from managed forest areas for pulpwood. There are no records available from either state or federal sources concerning the nature and quantities of potentially hazardous and/or explosive material that might be transported along U. S. Highway 1 in the vicinity of the plant site. Also, there are no apparent factors that should cause shipments along this route to differ significantly from shipments along any other federal highway. Since U. S. Highway 1 is a federal highway, it would be reasonable to assume that shipments of hazardous and/or explosive materials along it would conform to applicable federal and state regulations.

2.2.2.3 Pipelines

A Southern Natural Gas Company pipeline is located within approximately 4-1/2 miles of HNP-2 as shown on Figure 2.2-1. The pipeline, which was designed for 1200-psi operation carries natural gas at an operating pressure of 820 psi. The 12-3/4-inch-OD pipe ranges in wall thickness from 0.219 inch to 0.500 inch and in minimum yield strength from 35,000 psi to 52,000 psi. The pipeline was constructed in 1964 and is buried at a minimum depth of 30 inches. Figure 2.2-1 shows the location with respect to HNP-2 of ASA 600 #M&J M3 12-inch gate valves that can be used as isolation valves in the pipeline. The pipeline is not used for storage of gas at higher than normal pressure. The Southern Natural Gas Company does not anticipate using the pipeline to carry a product other than natural gas.

2.2.2.4 Waterways

There is no commercial traffic on the Altamaha River in the site region. Deen's Landing, a commercial launching facility for small boats, is located slightly over a mile upstream from the plant (see Figure 2.2-1). 1

2.2.2.5 Airports

The nearest airport with scheduled passenger service is in Waycross, Georgia, about 48 miles south of HNP-2. There are small municipal fields not used for scheduled commercial service at Baxley, about 13 miles south; Hazlehurst, about 16 miles southwest; Vidalia, about 20 miles north; and Alma, about 28 miles south.

2.2.2.6 Projections of Industrial Growth

The area within 5 miles of HNP-2 is largely rural, with most of the land being used for either residential or agricultural purposes. Much of the north-south vehicular traffic that traveled U. S. 1 in years past now moves along federal interstate highways. Other than the development of several trailer parks to accommodate the influx of construction workers associated with HNP, this area has remained relatively stable over the last several years and shows no tendencies toward any drastic changes in the foreseeable future.

2.2.3 EVALUATION OF POTENTIAL ACCIDENTS

2.2.3.1 Determination of Design Basis Events

The accident categories discussed below consider the potential for accidents at other facilities or transportation routes affecting HNP-2.

a. Explosions

   There are no known facilities or activities within a 5-mile radius of HNP where the process, storage, or use of high explosives, munitions, chemicals, or liquid and gaseous fuels would create the potential for accidental detonations that would pose a threat to HNP-2.

   Transportation routes within the 5-mile radius include the Altamaha River, a Southern Natural Gas Company pipeline, and the road system, principally U. S. 1. Traffic on the Altamaha River in the vicinity of HNP is not of a nature that would create the potential for accidental detonations that would pose a threat to HNP-2. The Southern Natural Gas Company pipeline is approximately 4-1/2 miles from HNP-2 and is sufficiently distant that potential detonations would not affect HNP-2. U. S. 1 passes approximately 3,400 feet west of the HNP-2 plant structures. Accidents involving possible detonation of materials or cargoes in transit on the highway would be sufficiently distant that HNP-2 would not be affected.

b. Flammable Vapor Clouds (Delayed Ignition)

   Accidental releases of flammable liquids or vapors that would result in the formation of unconfined vapor clouds from locations outside the 5-mile radius of HNP should be sufficiently dispersed, even under the most adverse meteorological conditions, so that the concentration by the time the cloud reaches HNP-2 is below the flammable point. The natural-gas pipeline, likewise, is sufficiently distant that the resulting cloud should be dispersed below the flammable concentration. The distance of U. S. 1 from HNP-2 and the comparative size of shipments that might be in transit along the highway should result in an exceedingly low probability of a cloud having a flammable concentration reaching HNP-2.

c. Toxic Chemicals

Gaseous chlorine is used in the HNP-1 and HNP-2 circulating water systems and service water systems. A maximum of sixteen 1-ton containers of chlorine will be contained in the chlorine storage facility which is located north of the HNP-1 circulating water flume. (The possibility of an inadvertent chlorine release has been considered in the design as discussed in Subsection 9.4.1).

One delivery per week by truck of twelve 1-ton chlorine cylinders is anticipated. Delivery will be made by a licensed carrier in accordance with DOT and ICC regulations. Onsite handling of chlorine cylinders will be by plant personnel trained in such procedures. Transportation of toxic chemicals along U. S 1 is sufficiently distant from HNP-2 that the probability of a toxic concentration resulting from a potential release reaching HNP-2 should be exceedingly low.

There are no other known storage or transportation facilities within a five-mile radius of HNP-2 that would pose a threat to HNP-2.

d. Fires

There are no nearby industrial, chemical, or storage facilities from which effects of fires would pose a threat to HNP-2. The Southern Natural Gas pipeline is sufficiently distant that a fire associated with the pipeline should not affect HNP-2. Likewise, fires associated with transportation accidents would be sufficiently distant as not to affect HNP-2. The terrain and ground cover surrounding HNP-2 are of a nature that would not be conducive to forest or brush fires that would have the potential for affecting HNP-2.

e. Collisions with Intake Structure

There is no commercial barge traffic on the Altamaha River in the vicinity of HNP-2 at present, and no future traffic is anticipated.

Barge traffic on the river would be required to have a permit from the U. S. Army Corp of Engineers with the exception of rafting or other movement of logs under Title 33 USC Sections 554 and 555. At 18
present, there are no permits or applications for permits from the

Corp of Engineers for any barge traffic on the river. The major companies with forestry operations in the vicinity of the river upstream of the plant site do not use barge logs. Only one of these companies has used barges to move logs down the river in the past. This particular company discontinued the use of barges prior to 1972 and has since disposed of all barges, tugboats, and other equipment that was used in its barging operations. The company has no plans to use barges on the river in the future.

The Savannah District Corp of Engineers removes snags and fallen trees from the river during a period of four to six months each year. The material removed by the Corp is placed on the river bank. For this operation, the Corp uses a barge 110 feet by 30 feet with a 7 foot draft which displaces 126 long tons and a towboat 61 feet by 21 feet with a 6 foot draft which displaces 80 long tons. Maximum speed of the barge and towboat would be five miles per hour. The towboat and barge would pass the plant site at most once moving upstream and once downstream per year and possibly as seldom as once every two or three years. However, as the towboat and barge would pass the plant site it would be engaged in snagging operations and would be moving at much less than its maximum speed. 18

The intake structure is protected, however, by sheet pile cells from a direct hit by river traffic or debris moving in the direction of the river flow. The cells are comprised of soil filled sheet piling and are 63 feet in diameter, extend from elevation 22'-0" to elevation 105'-0" and weigh approximately 14,500 tons.

f. Liquid Spills

There is no commercial barge traffic on the Altamaha River in the vicinity of HNP-2 at present. The nearest industrial plant upstream of HNP-2 is located near Macon, Georgia. Should any appreciable amount of corrosive, cryogenic, or coagulant oil or liquid be released into the river from an upstream location, the material should be diluted substantially before reaching the intake structure.

Heat-transfer areas of the heat exchanges might be affected initially. However, conservative sizing of heat-transfer surfaces and continuous flushing of service water flow would negate the effect of such materials on the heat exchangers.

2.2.3.2 Effects of Design Basis Events

Potential accidents other than the postulated release of chlorine gas considered above should have a negligible affect on HNP-2. A detailed discussion of a postulated chlorine accident and its effects on plant operation is presented in Subsection 15.1.42.