Duke Power
A Duke Energy Company

W. R. McCollum, Jr.
Vice President

Duke Power
Oconee Nuclear Site
7800 Rochester Highway
Seneca, SC 29672
(864) 885-3107 OFFICE
(864) 885-3564 FAX

July 26, 2000

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

Subject: Duke Energy Corporation
Oconee Nuclear Station, Units 1, 2 and 3
Docket Numbers 50-269, 50-270 and 50-287
Request for Exemption to 10CFR50.44, 10CFR50, Appendix A, General Design Criterion 41, and 10CFR50, Appendix E, Section VI.
Proposed Technical Specification Change Concerning Hydrogen Control System (TSCR 2000-05)

Pursuant to the provisions of 10 CFR 50.12, " Specific exemptions," Duke Energy Corporation (Duke) is requesting an exemption to the requirements of 10 CFR 50.44, "Standards for combustible gas control system in light-water-cooled power reactors," 10 CFR 50, Appendix A, General Design Criterion 41, "Containment atmosphere cleanup," and 10 CFR 50, Appendix E, Section VI, "Emergency Response Data System." The purpose of this exemption request is to remove requirements for hydrogen control systems (i.e., containment post-accident hydrogen monitors and recombiners) from the Oconee, Units 1, 2, and 3 (ONS) design basis. With this change, the consideration of hydrogen generation would no longer be included in the design basis of ONS. Accordingly, the enclosed Technical Specification (TS) Change Request 2000-05 would remove the post-accident hydrogen control systems from the ONS TS and provide the basis for deletion of a Selected Licensee Commitment concerning hydrogen recombiners.

Enclosure 1 provides the documentation supporting the exemption request. Enclosure 2 is a license amendment request, which consists of five attachments. Attachments A and B provide mark-up and new pages of the Oconee TS, respectively. The Description of Proposed Changes and Technical Justification is provided in Attachment C. Attachments D and E provide the No Significant Hazards Consideration Evaluation and Environmental Impact Analysis, respectively.

As described in the enclosures, approval of the requested exemption would improve the safety focus at Oconee and represent a more effective and efficient method for maintaining adequate protection of public health and safety. The requested changes would permit simplification of Emergency and Emergency Response Plan Procedures thereby reducing operators' post-accident burden. Such simplification would enable operators to give priority to more important safety functions following postulated plant accidents.

A001

It is Duke's intention that, upon NRC approval of this request, the description of the hydrogen control systems, its bases and other associated discussions would be removed from the UFSAR and from the Emergency and Emergency Response Plan Procedures.

A similar request for an exemption to the requirements of 10 CFR 50.44, and 10 CFR 50, Appendix A, General Design Criterion 41, 42 and 43 was approved by the NRC for San Onofre Nuclear Generation Station, Units 2 and 3, by letter dated September 3, 1999.

Implementation of this amendment to the Oconee Technical Specifications will impact the Oconee UFSAR. Necessary changes will be made in accordance with 10 CFR 50.71(e). Duke requests a 90-day grace period for implementation of this exemption request and the associated changes.

The Duke Nuclear Safety Review Board and the Oconee Plant Operations Review Committee have reviewed and approved this proposed Technical Specification amendment.

A copy of this application is being forwarded to the South Carolina Department of Health and Environmental Control for their review and, as appropriate, subsequent consultation with the staff.

Please contact Robert C. Douglas at 864-885-3073 with any questions regarding this submittal.

Very truly yours,

W. R. McCollum, Jr.
Site Vice President
Oconee Nuclear Station

Enclosures

xc: (w/enclosures)

L.A. Reyes
Administrator, Region II

M. C. Shannon
NRC Senior Resident Inspector
Oconee Nuclear Station

D. E. LaBarge
ONRR, Senior Project Manager

V.R. Autry, Director
DHEC

AFFIDAVIT

W. R. McCollum, Jr., being duly sworn, states that he is Site Vice President of Duke Energy Corporation; that he is authorized on the part of said corporation to sign and file with the Nuclear Regulatory Commission this exemption request and proposed revision to the Oconee Nuclear Station License Nos. DPR-38, DPR-47, and DPR-55; and that all statements and matters set forth therein are true and correct to the best of his knowledge.

W. R. McCollum, Jr., Site Vice President

Subscribed and sworn to me: July 26, 2000
Date

Notary Public: Robert C. Douglas

My Commission Expires: August 13, 2009
Date

Seal

ENCLOSURE 1

EXEMPTION REQUEST

10CFR50.44, "STANDARDS FOR COMBUSTIBLE GAS CONTROL SYSTEM IN LIGHT-WATER-COOLED POWER REACTORS"

10CFR 50, APPENDIX A, GENERAL DESIGN CRITERION 41, "CONTAINMENT ATMOSPHERE CLEANUP"

10CFR50, APPENDIX E, SECTION VI, "EMERGENCY RESPONSE DATA SYSTEM"

Table of Contents

1.0 INTRODUCTION

1.1. PURPOSE

This enclosure provides information in support of a request for exemption pursuant to Title 10 of the Code of Federal Regulations Part 50.12, Specific Exemptions, from requirements contained in 10CFR50.44 and 10CFR50, Appendix A, General Design Criterion 41 and 10CFR50, Appendix E.

The purpose of this request is to remove requirements for a hydrogen control system from the Oconee, Units 1, 2, and 3 (ONS) design basis. Additionally, Enclosure 2 to this submittal is a license amendment request that would remove requirements for hydrogen control system components from the ONS Technical Specification (TS) and provide a basis for changes to the Updated Final Safety Analysis Report (UFSAR) reflecting deletion of the system. These changes include deletion of the hydrogen monitors from the ONS TS and approve deletion of a Selected Licensee Commitment (Chapter 16 of the UFSAR) concerning requirements for hydrogen recombiners.

1.2. REGULATORY REQUIREMENTS

1.2.1. Requirements of 10CFR50.44, 10CFR50, Appendix A, General Design Criterion 41, and 10CFR50, Appendix E

Although the above listed requirements of 10CFR50 did not exist at the time ONS was licensed, the hydrogen control system recombiners, monitors and the hydrogen concentration parameter of the Emergency Response Data System have been credited to meeting the requirements as described below.

10CFR50.44, Standards for combustible gas control system in light-water-cooled power reactors, and 10CFR50, Appendix A, General Design Criterion 41, Containment atmosphere cleanup, establish requirements for controlling the amount of hydrogen inside the reactor containment following a postulated Loss of Coolant Accident (LOCA). These requirements provide specific assumptions and methods to define the amount of hydrogen generated, the rate at which the hydrogen is generated, and the requirements of a combustible gas control system to control the concentration of hydrogen in the containment following a design basis LOCA to below flammability limits. 10CFR50, Appendix E, Emergency Response Data System, contains requirements to provide information on the concentration of hydrogen inside the containment following accidents as part of the Emergency Response Data System.

As applied to ONS, the regulations require the following:

A means for control of hydrogen gas that may be generated, following a postulated LOCA by:

- metal-water reaction involving the fuel cladding and the reactor coolant;
- radiolytic decomposition of the reactor coolant; and,
- corrosion of metals.

The hydrogen control measures must be capable of:

- measuring and reporting the hydrogen concentration in the containment;
- insuring a mixed atmosphere in the containment; and,
- controlling combustible gas concentrations in the containment following a LOCA.

It must be shown that following a LOCA, but prior to effective operation of the combustible gas control system, either:

- an uncontrolled hydrogen-oxygen recombination would not take place in the containment; or,
- the plant could withstand the consequences of uncontrolled hydrogen-oxygen recombination without loss of safety function.

A combustible gas control system to maintain the concentrations of combustible gases following a LOCA below flammability limits. Such systems may be of two types:

- those allowing controlled release from containment such as a purge system;
- those that do not result in a significant release from containment such as recombiners.

Such a system must control hydrogen as necessary following a LOCA to assure that containment integrity is maintained.

1.2.2. Criteria for Exemptions - 10CFR50.12 Requirements

The Nuclear Regulatory Commission has established certain criteria that permit any interested person to request specific exemptions to its rules and regulations provided special circumstances exist. These criteria are promulgated in 10CFR50.12, Specific Exemptions:

The Commission may, upon application by any interested person or upon its own initiative, grant exemptions from the requirements of the regulations of this part which are authorized by the law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security.

The Commission will not consider granting an exemption unless special circumstances are present.

Special circumstances are identified in 10CFR50.12(a)(2). The special circumstance most relevant to ONS is:

(ii) Application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.

Special circumstances may also be present with respect to:

(iv) The exemption would result in benefit to the public health and safety that compensates for any decrease in safety that may result from the grant of the exemption.

(vi) There is present any other material circumstance not considered when the regulation was adopted for which it would be in the public interest to grant an exemption.

This enclosure provides documentation in support of ONSs request for an exemption.

2.0 TECHNICAL JUSTIFICATION

2.1. OVERVIEW

The containment Combustible Gas Control System installed in ONS, is in accordance with the requirements of 10CFR50.44 and 10CFR50, Appendix A, General Design Criterion (GDC) 41, to control the hydrogen concentration inside the reactor containment, following design basis Loss of Coolant Accident (LOCA) conditions, below the hydrogen limit of 4.0 volume percent (4.0%). The containment Post-Accident Hydrogen Control System design basis and recombiner system description is provided in the ONS Updated Final Safety Analysis Report (UFSAR) § 15.16[1]. Measurement and reporting of the hydrogen volume percentage is required by 10CFR50, Appendix E, Emergency Response Data System. The containment Hydrogen Monitoring System design basis is provided in UFSAR § 9.3.7 and the system description is provided in UFSAR § 7.5.2.10.

---

[1] The UFSAR references are provided for reviewer convenience as attachments to Enclosure 2, Attachment C as follows:

C-1 Selected Licensee Commitment 16.6.10, "Containment Recombiner System."
C-2 UFSAR § 6.5.3, "Fission Product Control Systems."
C-3 UFSAR § 7.5.2.10 and § 9.3.7 concerning containment hydrogen monitoring.
C-4 UFSAR § 15.16, "Post-accident Hydrogen Control."

2.2. DESIGN CONSIDERATIONS

2.2.1. System Description

The containment Post-Accident Hydrogen Control System consists of the Containment Hydrogen Monitoring System and the Containment Hydrogen Recombiner System. These are briefly described below.

2.2.1.1.1. Containment Hydrogen Monitoring System

Two redundant channels of hydrogen monitoring are provided that can monitor hydrogen concentrations at different levels of the containment including Containment Hydrogen Recombiner System inlet and return concentrations. The measurement capability is provided over the range of 0 to 10 volume percent. A continuous indication of the hydrogen concentration is not required in the control room. Following accidents, monitoring of hydrogen concentrations and recording in the control room shall be functioning in a sufficiently timely manner to support implementation of the Oconee Emergency Plan[2].

2.2.1.2. Containment Hydrogen Recombiner System

The Containment Hydrogen Recombiner System consists of a portable hydrogen recombiner, control panel for the recombiner, and piping. The Oconee recombiners are Thermal Hydrogen Recombiners developed and constructed by Rockwell International. Two recombiners are normally maintained at the Oconee site. Only one recombiner is required operable. Duke Power Company maintains a lease agreement with Carolina Power and Light (CP&L) and Florida Power and Light (FP&L) for use of a recombiner when needed at the H. B. Robinson Nuclear Site for CP&L and the Turkey Point Nuclear Site for FP&L.

The recombiner is normally not connected to a containment building. When needed post-accident, the recombiner and control cabinet will be moved to the affected unit. The control cabinet will then be installed on a pad near the recombiner. The recombiner will be anchored to its foundation and connected by flexible piping to the piping that runs to and from containment penetrations 60 and 61. The recombiner is capable of processing 90 standard cubic feet per minute with a recombination efficiency of at least 95% for hydrogen concentrations of greater than 0.5 volume percent. The minimum required flow rate for the design basis LOCA is 50 standard cubic feet per minute. Power for the Containment Hydrogen Recombiner System is normally supplied from non-safety power via the Auxiliary Power Upgrade Busses. In the event power is not available from the normal supply, power can be manually restored from either of two non-safety, non-loadshed power supplies.

[2] Letter, NRC to Duke, "Re: Confirmatory Order Modifying Post-TMI Requirements Pertaining to Containment Hydrogen Monitors," dated November 29, 1999

Following a LOCA, the process of placing the Containment Hydrogen Recombiner System in service is begun when the containment hydrogen concentration in containment reaches 0.5% by volume. The recombiner and control cabinet are placed on the appropriate pads of the affected Unit. Electrical and mechanical connections are made to connect the recombiner to the affected Unit. Mechanical connections are leak rate tested and valve alignments are made to align the Containment Hydrogen Recombiner System for operation.

The basic approach is to allow the hydrogen concentration to increase for a minimum of 7 days prior to placing the Containment Hydrogen Recombiner System in service. This allows time for pressures and temperatures to decrease in the Reactor Building prior to placing the system in service. Following Regulatory Guide 1.7 methodology, the hydrogen concentrations are conservatively calculated not to reach 4 volume percent in containment for 15 days after initiation of the design basis LOCA based on recent hydrogen generation analysis.

2.2.2. Supporting Systems

The Reactor Building Cooling Units (fans and coolers) and the Reactor Building Spray System accomplish hydrogen mixing within the containment. These systems and the internal structures of the containment are designed to maintain a well-mixed containment atmosphere, and to prevent hydrogen pocketing.

The Reactor Building Cooling Units and the Reactor Building Spray System start on automatic signals following a LOCA to remove heat and fission products from the containment atmosphere, as well as to minimize localized hydrogen buildup inside containment. This exemption request proposes no changes to the Reactor Building Cooling Units and the Reactor Building Spray System.

2.2.3. Impact of Requested Changes on Hydrogen Control

As explained below, the ONS hydrogen control is not significantly impacted by the proposed exemption request due to (1) existing margin in the containment design, and (2) due to its limited capacity, the existing containment Post-Accident Hydrogen Control System has no value in defense against containment failure resulting from hydrogen buildup inside the containment following severe accidents.

2.2.3.1. Impact of Hydrogen Control on Containment Safety Margin

ONS employs a large, dry containment design with a design pressure of 59 psig. The hydrogen burn during the 1979 event at Three Mile Island 2 (TMI-2) with a hydrogen concentration of about 8.1% resulted in a containment peak pressure of about 28 psig, well below the TMI-2 containment design pressure of 60 psig (NSAC-22, 1981). The ONS containment with a similar design has sufficient safety margin against hydrogen burn following design basis and severe accidents without use of the hydrogen control system.

Following a design basis LOCA, hydrogen could accumulate inside the containment and could reach the flammability limit. However, a review of the Oconee Individual Plant Examination (IPE) accident sequences concludes containment survival is almost certain following hydrogen combustion when the Reactor Building Cooling Units and the Reactor Building Spray System are operating. This is true for a hydrogen concentration significantly above the flammability limit. In these IPE accident sequences, no credit was taken for the containment Post-Accident Hydrogen Control System. This exemption request makes no changes to the Reactor Building Cooling Units and the Reactor Building Spray System. The IPE indicates that hydrogen combustion is not a serious threat to containment integrity when containment pressure control is effective.

Both the nuclear industry and the NRC conducted numerous analyses and tests following the event at TMI-2 in 1979 to determine the containment capability of pressurized water reactor plants with a large, dry containment. For example, NUREG/CR-5662 (1991) reports the computed containment peak pressure due to global hydrogen burn based on a 75% fuel cladding metal-water reaction (MWR) (which can be expected to occur during severe accidents) for a group of pressurized water reactor plants with large, dry containments, similar to the ONS containment. The reported containment peak pressure values are all within the plants estimated containment capacities. Therefore, the NRC-sponsored study concludes that it seems unlikely that containment integrity would be threatened by a hydrogen burn from a 75% MWR in the containments examined. The 75% MWR estimate was intended to be representative of a range of core melt accidents. It should be noted that the TMI-2 accident involved about 45% MWR which resulted in a hydrogen concentration of about 8.1% (NUREG/CR-4330, Volume 3, 1987). The NRC concluded that the large, dry containments could withstand the containment pressure following severe accidents and there was no need to backfit these containments with igniters or to inert the containment atmospheres.

A detailed plant-specific containment integrity analysis for ONS indicates that the ultimate pressure capacity of the Oconee containment building is approximately 140 psig, mean value (Oconee IPE, Section G). Hence, a safety margin exists for containment integrity at higher hydrogen concentration levels following a design basis LOCA, without the use of a hydrogen control system.

With respect to equipment survivability, NUREG/CR-5662 states:

> Equipment survivability depends on the specific plant design and on the containment environment during a specific accident. The large-scale Nevada test site experiments demonstrated that various types of plant equipment are capable of operating successfully when subjected to the severe thermal environments associated with large-volume hydrogen burns.
>
> The recent analytical and experimental study performed at Sandia National Laboratories showed that the simulated equipment can withstand a LOCA and

single burns resulting from a 75% MWR in a large, dry containment. However, the multiple burn due to the operation of ignition systems could pose a serious threat to safety-related equipment located in the source compartment.

It should be noted that the ONS containments do not have igniters. This reduces the potential for multiple burns. During the TMI-2 accident, containment was not breached and damage inside containment was essentially limited to plastics and other low melting point materials such as telephone cases and the crane operator's seat (NUREG/CR-4330, Volume 3, 1987).

Summary of Safety Margin Impact

For pressurized water reactor plants with large, dry containments, a safety margin remains for containment rupture from hydrogen burn or detonation at higher hydrogen concentration levels during severe accidents or following a design basis LOCA, without using any hydrogen control system. Additionally, the NRC has determined that pressurized water reactor plants with large, dry containments can withstand the containment pressure following severe accidents and there was no need to backfit these containments with igniters or to inert the containment atmospheres.

2.2.3.2. Impact of Hydrogen Control on Design Basis Accidents

The existing containment Post-Accident Hydrogen Control System meets the requirements of 10CFR50.44 and 10CFR50, Appendix A, GDC 41 to control the concentration of hydrogen which may be released into the reactor containment following postulated design basis accidents. The existing containment Post-Accident Hydrogen Control System is designed to ensure that the hydrogen concentration is maintained below the limit of 4.0 volume percent following a design basis LOCA. The Reactor Building Cooling Units, the Reactor Building Spray System, and the internal containment structural design provide excellent hydrogen mixing capability inside the containment that would prevent hydrogen pocketing following a postulated design basis LOCA. These hydrogen mixing systems are not impacted by this exemption request.

The containment Post-Accident Hydrogen Control System design basis is provided in ONS UFSAR, § 15.16. Analyses show hydrogen concentrations of approximately 1% after the first day and 3% at about 9 days after a postulated design basis LOCA. Using the current assumptions, the hydrogen concentration would reach the limit of 4.0% at about 15 days following a design basis LOCA, given that the control room operators do not start the hydrogen recombiner.

Following a design basis LOCA, hydrogen could accumulate inside the containment and could reach the flammability limit. However, a review of the Oconee Individual Plant Examination (IPE) accident sequences concludes containment survival is almost certain following hydrogen combustion when the Reactor Building Cooling Units and the Reactor Building Spray System are operating. This is true for hydrogen concentration significantly

above the flammability limit. In these IPE accident sequences, no credit was taken for the containment Post-Accident Hydrogen Control System. This exemption request makes no changes to the Reactor Building Cooling Units and the Reactor Building Spray System. The IPE indicates that hydrogen combustion is not a serious threat to containment integrity when containment pressure control is effective.

There is also no potential for containment integrity to be challenged due to hydrogen pocketing, based on ONS containment internal structural design (generous vent paths) and availability of safety-related Containment Air Mixing Systems which are not impacted by this exemption. The results of a study for several PWR plants with large dry containments indicated that, depending on the containment volume and fan capacity, a mixing of the total containment air volume by fans alone would take only 10 to 30 minutes for the PWRs examined (NUREG-CR-5662, § 2.3). The time required to process one containment volume for ONS is approximately 30 minutes.

<u>Summary of Design Basis Accident Impact</u>

The containment Post-Accident Hydrogen Control System is designed to maintain the hydrogen concentration level below the flammability limit during design basis accidents. Without operation of the hydrogen control system, the hydrogen concentration could be expected to rise above the limit of 4.0% following a design basis LOCA and the assumptions presently used for accident analysis. However, containment failure due to hydrogen combustion is highly unlikely based on the results of the ONS Individual Plant Examination.

2.2.3.3. Impact of Hydrogen Control on Severe Accidents

For severe accidents, i.e., those beyond the design basis, containment hydrogen concentrations in the range of 10% over short periods of time are possible, as demonstrated at the TMI-2 accident in 1979. The containment Post-Accident Hydrogen Control System is designed to maintain the hydrogen concentration level below the limit of 4.0% during design basis accidents that result in small amounts of hydrogen produced slowly over long periods of time--i.e., many days. For severe accidents during which containment hydrogen concentration will rapidly rise to above the 4.0% level, the present containment Post-Accident Hydrogen Gas Control System is undersized, and hence would provide no benefit to hydrogen concentration control and containment performance. An NRC-sponsored study (NUREG/CR-5567, 1990) corroborates this point by stating that the hydrogen control systems are designed to accommodate hydrogen accumulation for design basis events (oxidation of 5% Zircaloy surrounding the active fuel). These systems are not designed for the hydrogen generation that might accompany a reactor core meltdown. Consequently, the containment Post-Accident Hydrogen Control System was determined to be ineffective in mitigating hydrogen in the ONS Individual Plant Examination. Subsequent to the TMI-2 accident, improvements in equipment, operator training, and procedures make it extremely unlikely that a severe core damaging event comparable to TMI-2 would occur at ONS.

The hydrogen recombiner is ineffective at processing hydrogen at the higher rates expected to be generated during severe core damage accidents. The ONS hydrogen recombiners have a 90 standard ft^3/min capacity so that each is undersized for severe accidents. The ONS PRAs have not assumed any hydrogen mitigation function by the hydrogen recombiners for severe accidents. Approval of this exemption would have no impact on the public health risk as assessed in the ONS PRAs.

The usefulness of the Containment Hydrogen Monitoring System is very limited during severe accidents. The only safety-related use of the Containment Hydrogen Monitoring System is to provide the containment hydrogen concentration as a basis for actuating the recombiner.

Summary of Severe Accident Impact

The usefulness of the existing containment Post-Accident Hydrogen Control System is limited to design basis accidents. The system is undersized for severe accidents, and hence provides no benefit for these severe accidents. However, containment failure due to hydrogen combustion is highly unlikely based on the results of the ONS Individual Plant Examination.

Conclusion

The proposed exemption does not affect the consequences of any potential ONS accident due to (1) existing margin in the containment design, and (2) due to its limited capacity, the containment Post-Accident Hydrogen Control System provides no benefit for severe accidents.

2.2.4. Additional Considerations

Risk Reduction

In a postulated LOCA, control room operators monitor the hydrogen concentration inside the containment after they have carried out the steps to maintain and control the higher priority critical safety functions such as reactivity, RCS inventory, RCS pressure, and core heat removal. Given an indication of increasing hydrogen concentration by the hydrogen monitors, the key operator actions in controlling the hydrogen concentration are to place the hydrogen recombiner in operation. Placing the recombiner into operation involves many procedural steps and requires coordination between many groups of people.

In the case of a severe accident in which the reactor core is damaged, any attempt to install the hydrogen recombiner would be detrimental to worker health and safety. Worker actions to activate the portable hydrogen recombiner occur just outside the Reactor

Building containment. To be used, the recombiner must be moved from its storage location to an area adjacent to the Reactor Building containment. The recombiner must then be connected to electrical power sources and mechanically connected to the containment, leak tested, and then placed in service. This involves many procedural steps and requires coordination between control room operators and other work groups, such as Maintenance, Instrumentation and Control, and Radiation Protection. Such actions could jeopardize the health and safety of the personnel performing the installation of the hydrogen recombiner because of the radiation fields that could be present outside the containment during severe accidents.

In addition, placing the recombiner in service would extend the containment boundary (with the use of several hundred feet of piping and associated mechanical connections) increasing the probability of uncontrolled/unfiltered leakage of the containment atmosphere. As discussed previously, these hydrogen control activities are of no benefit in mitigating severe accidents.

An exemption from the requirements for a hydrogen control system would eliminate the need for Emergency Operating Procedure steps for hydrogen monitoring and hence simplify the EOPs. The information provided by the hydrogen monitors concerning the hydrogen concentration is unneeded for post-accident decision making associated with containment integrity. The monitors are therefore unneeded. Approval of this exemption request would also eliminate the requirement for the installation of the hydrogen recombiner thus simplifying the actions of workers following severe accidents and eliminating potential containment atmospheric leakage from the hydrogen recombiner piping.

Summary of Risk Reduction

The information provided by the hydrogen monitors concerning the hydrogen concentration is unneeded for post-accident decision making associated with containment integrity. The monitors are therefore unneeded. Exemption from the requirements for installation of the portable hydrogen recombiner will also eliminate the potential for containment atmospheric leakage from the hydrogen recombiner piping. The changes described in this exemption request will also have a positive impact on worker health and safety.

2.3. INDUSTRY EXPERIENCE

The regulatory requirements for containment hydrogen control systems were based on knowledge that existed before the TMI-2 event in March 1979. Following TMI-2, the nuclear industry and the NRC initiated extensive analysis and testing to increase the scope of knowledge concerning hydrogen generation and hydrogen control following severe accidents. This new knowledge invalidated many of the assumptions and methods in the regulations. Based on the new knowledge, it became clear that hydrogen control systems designed for design basis LOCA conditions were not adequate in severe accidents to maintain the hydrogen concentration below the postulated flammability limit of 4 volume

percent. Following TMI-2, the nuclear industry performed extensive analysis and testing which indicated that for large, dry containments, the containment would withstand the burn of large amounts of hydrogen generated in severe accidents. Therefore, the required hydrogen control systems were determined to be unnecessary for design basis LOCA conditions, and ineffective for severe accidents.

In addition, the Nuclear Regulatory Commission conducted analyses with respect to backfitting the installation of igniters to replace the hydrogen recombiners in nuclear units with large, dry containments. The NRC determined that the requirement for igniters could not be justified for nuclear units with large, dry containments according to the provision of 10 CFR 50.109. This was because large, dry containments have a greater ability to accommodate the large quantity of hydrogen associated with a degraded core accident than the smaller containments.[3] To date, the nuclear units with large, dry containments rely exclusively on the containment structure to withstand any postulated uncontrolled burn of hydrogen gas generated in severe accidents.

2.4. CONCLUSION

The existing Post-Accident Hydrogen Control System is of no benefit in severe accidents. The reduction in hydrogen concentration provided by the recombiners has no impact on containment integrity for design basis accidents because containment failure due to hydrogen combustion is highly unlikely. In addition, the information provided by the hydrogen monitors concerning the hydrogen concentration is unneeded for post-accident decision making associated with containment integrity. The monitors are therefore unneeded. Further, elimination of the present requirements to connect the portable hydrogen recombiner to the Reactor Building containment following an accident will have a positive impact on public health risk and worker health risk.

3.0 EXEMPTION CRITERIA OF 10CFR50.12

3.1. OVERVIEW

The present compliance with 10CFR50.44, 10CFR50, Appendix A, General Design Criterion 41, and 10CFR50, Appendix E (the rule) at ONS does not serve the underlying purpose of the rule and is not useful in achieving the underlying purpose of the rule. The underlying purpose of the rule was to provide assurance that the containment would not fail due to combustible gas accumulation and ignition in accident situations where fission products were present in the containment. Reliance on the design basis LOCA conditions described in the rule was not useful for large dry containments since they can withstand hydrogen combustion from a severe accident.

[3] NUREG/CR-5662, 1991

The TMI-2 accident produced hydrogen in quantities far exceeding the assumptions in 10CFR50.44, and, although an uncontrolled hydrogen burn did occur, the containment did not fail.

Probabilistic Risk Assessments (PRAs) quantify the probabilities and consequences of similar accidents. In the PRAs performed for the Oconee Individual Plant Examination and Individual Plant Examination for External Events (IPEEE), the containment Post-Accident Hydrogen Control System was determined to be ineffective in addressing hydrogen concentrations in severe accidents. The containment Post-Accident Hydrogen Control System diverts operator attention from more important actions.

As described below, the requested exemption to the requirements of 10CFR50.44, 10CFR50, Appendix A, General Design Criterion 41, and 10CFR50, Appendix E satisfies the requirements of 10CFR50.12. The purpose of this exemption request is to remove the requirements for the Containment Hydrogen Monitoring System and the Containment Hydrogen Recombiner System from the ONS design basis. As such, the consideration of hydrogen generation will no longer be included in the design basis of ONS.

3.2. NO UNDUE RISK

Section (a) (1) [There is no undue risk to the public health and safety]

As stated earlier, eliminating the hydrogen control requirements does not affect the ONS containment safety margin due to the fact that containment failure due to hydrogen combustion is very unlikely based on the results of the ONS Individual Plant Examination. Furthermore, the usefulness of the existing containment Post-Accident Hydrogen Control System is limited to design basis accidents that result in small amounts of hydrogen produced slowly over long periods of time (many days). The system has no benefit for severe accidents since containment failure due to hydrogen combustion is highly unlikely.

A detailed ONS containment integrity analysis indicates that the ultimate pressure capacity of the ONS containment buildings are approximately 140 psig, mean value (Oconee IPE, Section G). Hence, a safety margin exists for containment integrity at higher hydrogen concentration levels without using the existing containment post-accident Hydrogen Control System.

Eliminating the hydrogen control requirements for the ONS large dry containments has a positive impact on the risk to the public by simplifying the Emergency Operating Procedures and preventing additional potential leakage of the containment atmosphere by eliminating requirements for installation of the portable hydrogen recombiner.

3.3. UNDERLYING PURPOSE OF THE RULE NOT SERVED

Section (a)(2) (ii) [Application of the regulation in the particular circumstances would not serve the underlying purpose of the rule and is not necessary to achieve the underlying purpose of the rule]

The underlying purpose of the rule was to reduce the probability of failure of containment during accidents and thus prevent fission products from the reactor core from being released through the containment during an accident. Application of the rule at ONS has resulted in equipment and procedures that have no impact on the probability of failure of the containment under conditions where fission products from the reactor core exist in the containment. In the Oconee Individual Plant Examination and Individual Plant Examination for External Events, the Containment Hydrogen Monitoring System and the Containment Hydrogen Recombiner System were determined to be ineffective in controlling hydrogen concentrations in severe accidents. The requirements for the Hydrogen Monitoring System and the Hydrogen Recombiner System divert operator attention from more important actions. These systems have no benefit for ONS since containment failure due to uncontrolled hydrogen combustion is highly unlikely.

3.4. BENEFIT TO PUBLIC HEALTH AND SAFETY

Section (a)(2) (iv) [There is a benefit to the public health and safety]

Implementation of the exemption from the hydrogen control requirements would achieve a benefit to the public health and safety. In addition to the direct positive impact on the public health and safety by reducing the public risk (see Section 2.2.4), there is also an indirect safety benefit to the public. The indirect benefit comes from eliminating unnecessary requirements from the ONS Technical Specifications and Emergency Operating Procedures. The recent NRC statement on compliance versus safety[4]: "Requirements that are duplicative, unnecessary, or unnecessarily burdensome can actually have a negative safety impact," is a recognition of the indirect safety benefit of the proposed exemption.

3.5. MATERIAL CIRCUMSTANCES NOT CONSIDERED

Section (a)(2)(vi) [There are present material circumstances not considered when the regulation (i.e., 10CFR50.44) was adopted]

Experience and information obtained over time provide a better perspective about hydrogen generation and the impact of hydrogen burning on containment integrity and safety equipment during accidents. Two important material circumstances are (a) the effects and (b) the risks of hydrogen generation.

---

[4] NRC Inspection Manual Part 9900, Operations - Safety and Compliance, issued 09/09/97

a. *Effects of hydrogen generation*

Traditionally, technical and regulatory evaluation perspectives have held that a hydrogen burn is to be avoided due to the uncertainties of containment failure. The TMI-2 accident in March 1979 provided an important benchmark for the effects of a hydrogen burn on safety equipment and containment integrity. TMI-2, which involved about a 45% core cladding-water reaction, resulting in about 8.1% hydrogen concentration, produced no containment breach and minimal damage to equipment (NUREG/CR-4330, Vol. 3, 1987). The containment peak pressure was about 28 psig, well below the containment design pressure of 60 psig. Containment damage was essentially limited to plastics and other low melting point materials such as telephone cases and the crane operator's seat. The TMI-2 hydrogen burn thus provides actual experience which establishes a significantly higher threshold for containment damage than was thought to be available when the regulations were promulgated.

b. *Risks of hydrogen generation*

Many PRA evaluations (e.g., plant-specific IPEs) and tools (e.g., MAAP code) have been developed which provide a better insight about the risks of hydrogen generation and burning during severe accidents than were available when the regulations were promulgated. The ONS Individual Plant Examination concluded that the containment failure due to hydrogen combustion during severe accidents is very unlikely.

3.6. CONCLUSION

As discussed above, this exemption request is in compliance with 10CFR50.12, specifically, with applicable Sections (a)(1) and (a)(2)(ii). The discussion has demonstrated (1) that granting the exemption will not present an undue risk to public health and safety, and (2) that application of the rule in the particular circumstance would not serve the underlying purpose of the rule and is not necessary to achieve the underlying purpose of the rule. Additionally, special circumstances may also exist with respect to Section (a)(2)(iv) and Section (a)(2)(vi).

ENCLOSURE 2

AMENDMENT APPLICATION

This is a request to revise Oconee Nuclear Station, Units 1, 2, and 3 Technical Specification (TS) 3.3.8, "Post Accident Monitoring (PAM) Instrumentation," and the associated TS Bases. Additionally, Selected Licensee Commitment (SLC), 16.6.10, " Containment Hydrogen Recombiner System," would be deleted on approval of this application. Other changes described in this enclosure would be implemented on approval of the exemption requested provided in Enclosure 1 and this license amendment application.

This Application consists of:

Attachment A - Markup Technical Specification and Bases Pages

Attachment B - Replacement Technical Specification and Bases Pages

Attachment C - Description and Technical Justification of Proposed Changes

Attachment D - No Significant Hazards Consideration Evaluation

Attachment E - Environmental Impact Analysis

ENCLOSURE 2

ATTACHMENT A

Markup Technical Specification and Bases Pages

3.3 INSTRUMENTATION

3.3.8 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.8 The PAM instrumentation for each Function in Table 3.3.8-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTES--

1. LCO 3.0.4 is not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----------NOTE----------- Not applicable to Functions ~~14, 18, 19, 20 and 22~~ 13, 17, 18, 19 AND 21. ----------------------------- One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.6.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. -----------NOTE----------- Not applicable to Functions ~~10, 14, 18, 19, 20 and 22~~ 13, 17, 18, 19 AND 21. ----------------------------- One or more Functions with two required channels inoperable.	C.1	Restore one channel to OPERABLE status.	7 days
~~D. -----------NOTE----------- Only applicable to Function 10. ----------------------------- Two required channels inoperable.~~	~~D.1~~	~~Restore one required channel to OPERABLE status.~~	~~72 hours~~
~~E.~~ D -----------NOTE----------- Only applicable to Function ~~14.~~ 13. ----------------------------- One required channel inoperable.	~~E.1~~ D.1	Restore required channel to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E ~~F.~~ ------------NOTE------------ Only applicable to Functions ~~18, 19, 20, and 22.~~ 17, 18, 19, AND 21. ------------------------------------ One or more Functions with required channel inoperable.	~~F.1~~ E.1 Declare the affected train inoperable.	Immediately
F. ~~G.~~ Required Action and associated Completion Time of Condition C, ~~D~~ or ~~E~~ D not met.	~~G.1~~ F.1 Enter the Condition referenced in Table 3.3.8-1 for the channel.	Immediately
G. ~~H.~~ As required by Required Action ~~G.1~~ F.1 and referenced in Table 3.3.8-1.	~~H.1~~ G.1 Be in MODE 3. <u>AND</u> ~~H.2~~ G.2 Be in MODE 4.	12 hours 18 hours
H. ~~I.~~ As required by Required Action ~~G.1~~ F.1 and referenced in Table 3.3.8-1.	~~I.1~~ H.1 Initiate action in accordance with Specification 5.6.6.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
These SRs apply to each PAM instrumentation Function in Table 3.3.8-1 except where indicated.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.8.2	---NOTE--- Only applicable to PAM Functions 7, ~~10~~ and 21. ~~22.~~ --- Perform CHANNEL CALIBRATION.	 12 months
SR 3.3.8.3	---NOTE--- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. Not applicable to PAM Functions 7, ~~10,~~ and ~~22.~~ 21. --- Perform CHANNEL CALIBRATION.	 18 months

Table 3.3.8-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION G.1 ← F.1
1.	Wide Range Neutron Flux	2	G → H
2.	RCS Hot Leg Temperature	2	G → H
3.	RCS Hot Leg Level	2	I ← H
4.	RCS Pressure (Wide Range)	2	G → H
5.	Reactor Vessel Head Level	2	I ← H
6.	Containment Sump Water Level (Wide Range)	2	G → H
7.	Containment Pressure (Wide Range)	2	G → H
8.	Containment Isolation Valve Position	2 per penetration flow path[a][b][c]	G → H
9.	Containment Area Radiation (High Range)	2	I ← H
~~10.~~	~~Containment Hydrogen Concentration~~	~~2~~	~~H~~
10 → 11	Pressurizer Level	2	G → H
11 → 12	Steam Generator Water Level	2 per SG	G → H
12 → 13	Steam Generator Pressure	2 per SG	G → H
13 → 14	Borated Water Storage Tank Water Level	2	G → H
14 → 15	Upper Surge Tank Level	2	G → H
15 → 16	Core Exit Temperature	2 independent sets of 5[d]	G → H
16 → 17	Subcooling Monitor	2	G → H
17 → 18	HPI System Flow	1 per train	NA
18 → 19	LPI System Flow	1 per train	NA
19 → 20	Reactor Building Spray Flow	1 per train	NA
20 → 21	Emergency Feedwater Flow	2 per SG	G → H
21 → 22	Low Pressure Service Water Flow to LPI Coolers	1 per train	NA

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Position indication requirements apply only to containment isolation valves that are electrically controlled.

(d) The subcooling margin monitor takes the average of the five highest CETs for each of the ICCM trains.

FOR INFORMATION ONLY

B 3.3 INSTRUMENTATION

B 3.3.8 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Events.

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed, and so that the need for and magnitude of further actions can be determined. These essential instruments are identified by the ONS specific Regulatory Guide 1.97 analysis (Ref. 1), UFSAR, Section 7.5 (Ref. 2), and the NRC's Safety Evaluation Report for the ONS Regulatory Guide 1.97 analysis (Ref. 3) which address the recommendations of Regulatory Guide 1.97 (Ref. 4), as required by Supplement 1 to NUREG-0737 (Ref. 5).

The instrument channels required to be OPERABLE by this LCO equate to two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category 1 variables.

Type A variables are specified because they provide the primary information that permits the control room operator to take specific manually controlled actions that are required when no automatic control is provided and that are required for safety systems to accomplish their safety functions for accidents.

Category 1 variables are the key variables deemed risk significant because they are needed to:

- Determine whether systems important to safety are performing their intended functions;

BASES

BACKGROUND (contonued)

- Provide information to the operators that will enable them to determine the potential for causing a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

These key variables are identified by the ONS specific Regulatory Guide 1.97 analysis (Ref. 1). This analysis identifies the unit specific Type A and Category 1 variables and provides justification for deviating from the NRC proposed list of Category 1 variables.

The specific instrument Functions listed in Table 3.3.8-1 are discussed in the LCO Bases Section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the availability of information so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures. These variables are restricted to preplanned actions for the primary success path of accidents (e.g., loss of coolant accident (LOCA));
- Take the specified, preplanned, manually controlled actions, for which no automatic control is provided, which are required for safety systems to accomplish their safety functions;
- Determine whether systems important to safety are performing their intended functions;
- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and estimate the magnitude of any impending threat.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The ONS specific Regulatory Guide 1.97 analysis (Ref. 1) documents the process that identifies Type A and Category 1 non–Type A variables. PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36 (Ref. 6). Category 1, non-type A, instrumentation must be retained in Technical Specifications because it is intended to assist operators in minimizing the consequences of accidents. Category 1, non-Type A variables are important for reducing public risk, and therefore, satisfy Criterion 4 of 10 CFR 50.36 (Ref. 6).
LCO	LCO 3.3.8 requires two OPERABLE channels for all but one Function to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident. Furthermore, provision of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. Where a channel includes more than one control room indication, such as both an indicator and a recorder, the channel is OPERABLE when at least one indication is OPERABLE. The exception to the two channel requirement is containment isolation valve position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each electrically controlled containment isolation valve. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the electrically controlled valve and prior knowledge of the passive valve or via system boundary status. If a normally active containment isolation valve is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Each of the specified instrument Functions listed in Table 3.3.8-1 are discussed below:

BASES

LCO (continued)

1. Wide Range Neutron Flux

Wide Range Neutron Flux indication is a Type B, Category 1 variable provided to verify reactor shutdown. The Wide Range Neutron Flux channels consist of two channels of fission chamber based instrumentation with readout on one recorder. (Note: four channels are available only two are required). The channels provide indication over a range of 1E-8% to 200% RTP.

2. Reactor Coolant System (RCS) Hot Leg Temperature

RCS Hot Leg Temperature instrumentation is a Type B, Category 1 variable provided for verification of core cooling and long term surveillance. The two channels provide readout on two indicators. Control room display is through the inadequate core cooling monitoring system. The channels provide indication over a range of 50°F to 700°F.

3, 5. Reactor Vessel Head Level and RCS Hot Leg Level

Reactor Vessel Water Level instrumentation is a Type B, Category 1 variable provided for verification and long term surveillance of core cooling. The reactor vessel level monitoring system provides an indication of the liquid level from the top of the Hot Leg on each steam generator to the bottom of the Hot Leg as it exits the vessel and from the top of the reactor vessel head to the bottom of the Hot Leg as it exits the vessel. Compensation is provided for impulse line temperature variations.

The Reactor Vessel Water Level channels consist of two Reactor Vessel Head Level channels that provide readout on two indicators (RC-LT0125 and RC-LT0126) with one channel recorded in the control room and two RCS Hot Leg Level channels that provide readout on two indicators (RC-LT0123 and RC-LT0124) with one channel recorded in the control room.

4. RCS Pressure (Wide Range)

RCS Pressure (Wide Range) instrumentation is a Type A, Category 1 variable provided for verification of core cooling and RCS integrity long term surveillance.

LCO

4. RCS Pressure (Wide Range) (continued)

Wide range RCS loop pressure is measured by pressure transmitters with a span of 0 psig to 3000 psig. The pressure transmitters are located outside the RB. Redundant monitoring capability is provided by two trains of instrumentation. Control room indications are provided through the inadequate core cooling plasma display. The inadequate core cooling plasma display is the primary indication used by the operator during an accident. Therefore, the accident monitoring specification deals specifically with this portion of the instrument string.

RCS Pressure is a Type A, Category 1 variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator (SG) tube rupture or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting SG pressure or level, would use this indication. In addition, high pressure injection (HPI) flow is throttled based on RCS Pressure and subcooled margin. For some small break LOCAs, low pressure injection (LPI) may actuate with RCS pressure stabilizing above the shutoff head of the LPI pumps. If this condition exists, the operator is instructed to verify HPI flow and then terminate LPI flow prior to exceeding 30 minutes of LPI pump operation against a deadhead pressure. RCS Pressure, in conjunction with LPI flow, is also used to determine if a core flood line break has occurred.

6. Containment Sump Water Level (Wide Range)

Containment Sump Water Level (Wide Range) instrumentation is a Type B, Category 1 variable provided for verification and long term surveillance of RCS integrity. The Containment Sump Water Level instrumentation consists of two channels with readout on two indicators (LT-90 and LT-91) and one recorder. The indicated range is 0 to 15 feet.

LCO (continued)

7. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) instrumentation is a Type B, Category 1 variable provided for verification of RCS and containment OPERABILITY. Containment Pressure instrumentation consists of two channels with readout on two indicators (PT-230 and PT-231) and one channel recorded. The indicated range is -5.0 psig to 175 psig.

8. Containment Isolation Valve Position

Containment isolation valve (CIV) position is a Type B, Category 1 variable provided for verification of electrically controlled containment isolation valve position. In the case of CIV position, the important information is the isolation status of the containment penetration. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each electrically controlled CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two electrically controlled valves. For containment penetrations with only one electrically controlled CIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration via indicated status of the electrically controlled valve, as applicable, and prior knowledge of passive valve or system boundary status. As indicated by Note (a) to the Required Channels, if a penetration flow path is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured, position indication for the CIV(s) in the associated penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration flow path is not required to be OPERABLE. Note (c) to the Required Channels indicates that position indication requirements apply only to CIVs that are electrically controlled. The CIV position PAM instrumentation consists of limit switches that operate both Closed-Not Closed and Open-Not Open control switch indication via indicating lights in the control room.

BASES

LCO (continued)

9. <u>Containment Area Radiation (High Range)</u>

Containment Area Radiation (High Range) instrumentation is a Type C, Category 1 variable provided to monitor the potential for significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. The Containment Area Radiation instrumentation consists of two channels (RIA 57 and 58) with readout on two indicators and one channel recorded. The indicated range is 1 to 10^7 R/hr.

~~10. Containment Hydrogen Concentration~~

~~Containment Hydrogen Concentration instrumentation is a Type A, Category 1 variable provided to detect high hydrogen concentration conditions that represent a potential for containment breach. This variable is also important in verifying the adequacy of mitigating actions. The Containment Hydrogen Concentration instrumentation consists of two channels (MT 80 and 81) with readout on two indicators and one channel recorded. The indicated range is 0 to 10% hydrogen concentration.~~

10. ~~11.~~ <u>Pressurizer Level</u>

Pressurizer Level instrumentation is a Type A, Category 1 variable used in combination with other system parameters to determine whether to terminate safety injection (SI), if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition. The Pressurizer Level instrumentation consists of three channels (two for Train A and one for Train B) with two channels indicated and one channel recorded.

(Note: three channels are available only two are required). The indicated range is 0 to 400 inches (11% to 84% level as a percentage of volume).

BASES

LCO (continued)

11. → 12. Steam Generator Water Level

Steam Generator Water Level instrumentation is a Type A, Category 1 variable provided to monitor operation of decay heat removal via the SG. The indication of SG level is the extended startup range level instrumentation, covering a span of 0 inches to 388 inches above the lower tubesheet.

The operator relies upon SG level information following an accident (e.g., main steam line break, steam generator tube rupture) to isolate the affected SG to confirm adequate heat sinks for transients and accidents.

The extended startup range Steam Generator Level instrumentation consists of four transmitters (two per SG) that feed four gauges.

12 → 13 Steam Generator Pressure

Steam Generator Pressure instrumentation is a Type A, Category 1 variable provided to support operator diagnosis of a main steam line break or SG tube rupture accident to identify and isolate the affected SG. In addition, SG pressure is a key parameter used by the operator to evaluate primary-to-secondary heat transfer.

Steam generator pressure measurement is provided by two pressure transmitters per SG. Each instrument channel inputs to the ICCM cabinet that provide safety inputs to two indicators located on the main control board in the control room. One channel per SG also provides input to a recorder located in the control room.

13. → 14. Borated Water Storage Tank (BWST) Level

BWST Level instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements, i.e., to determine when to initiate the switch over of the core cooling pump suction from the BWST to sump recirculation. BWST level measurement is provided by three channels with readout on two indicators and one recorder. (Note: three channels are available only two are required). Two of the three channels provide inputs

BASES

LCO

13 → ~~14.~~ Borated Water Storage Tank (BWST) Level (continued)

to the ICCM cabinet which provides inputs to qualified indicators on the Control Board. The third channel provides a safety input to a dedicated recorder. The channels provide level indication over a range of 0 to 50 feet (13% to 100% of volume).

14 → ~~15.~~ Upper Surge Tank (UST) Level

Upper Surge Tank Level instrumentation is a Type A, Category 1 variable provided to ensure a water supply for EFW. EFW draws condensate grade suction from the USTs and the Condenser Hotwell.

Two Category 1 instrumentation channels are provided for monitoring UST level. These instrument channels are inputs to corresponding train A and B Inadequate Core Cooling Monitoring (ICCM) system cabinets. The ICCM Train A cabinet provides UST level input to a dedicated qualified recorder and to a qualified indicator, both located in the Control Room. The ICCM Train B cabinet also provides an input to a qualified indicator located in the Control Room. The range of UST level indication is 0 to 12 feet.

UST Level is the primary indication used by the operator to identify loss of UST volume. The operator can then decide to replenish the UST or align suction to the EFW pumps from the hotwell.

15 → ~~16.~~ Core Exit Temperature

Core Exit Temperature is a Type A, Category 1 variable provided for verification and long term surveillance of core cooling.

The operator relies on this information following a LOCA to secure HPI and throttle LPI, following a SBLOCA to throttle HPI and begin forced HPI cooling if needed, and following a MSLB and SG Tube Rupture to throttle HPI and isolate the affected SG.

BASES

LCO 15. → 18.

Core Exit Temperature (continued)

There are a total of 52 Core Exit Thermocouples (CETs) per Oconee Unit. Twenty-four (12 per train) meet seismic and environmental qualification requirements (Category 1). The unit computer is the primary display for all 52 CETs. The CETs are distributed to provide monitoring of four or more in each quadrant for each train. The ICCM plasma displays (1 per train) located in the Control Room serve as safety related backup displays for the twenty-four Category 1 CETs. The range of the readouts is 50°F to 2300°F.

The ICCM CET function uses inputs from twelve incore thermocouples per train to calculate and display temperatures of the reactor coolant as it exits the core and to provide indication of thermal conditions across the core at the core exit. Each of the twelve qualified thermocouples per train is displayed on a spatially oriented core map on the plasma display. Trending of CET temperature is available continuously on the plasma display. The average of the five hottest CETs is trendable for the past forty minutes.

An evaluation was made of the minimum number of valid core exit thermocouples (CETs) necessary for inadequate core cooling detection. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and to trend the ensuing core heatup. The evaluations account for core nonuniformities and cold leg injection. Based on these evaluations, adequate or inadequate core cooling detection is ensured with two sets of five valid CETs.

Table 3.3.8-1 Note (d) indicates that the subcooling margin monitor takes the average of the five highest

CETs for each of the ICCM trains. Two channels ensure that a single failure will not disable the ability to determine the representative core exit temperature.

BASES

LCO (continued)

16. 17. Subcooling Monitor

The Subcooling Monitor is a Type A, Category 1 variable provided for verification and long term surveillance of core cooling. This variable is a computer calculated value using various inputs from the Primary System.

Two channels of indication are provided. An operable Subcooling Monitor shall consist of: 1) One direct indication from one channel for RCS Loop Saturation margin and one direct indication from the other channel for Core Saturation margin, or 2) One direct indication from each of the two channels for RCS Loop Saturation margin. The indication readouts are located in the control room. This variable also inputs to the unit computer through isolation buffers and is available for trend recording upon operator demand. The range of the readouts is 200°F subcooled to 50°F superheat. The control room display is through the ICCM plasma display unit.

A backup method for determining subcooling margin ensures the capability to accurately monitor RCS subcooling margin (Refer to Specification 5.5.17).

17. 18. HPI System Flow

HPI System Flow instrumentation is a Type A, Category 1 variable provided to support action for short term cooling requirements, to prevent HPI pump runout and inadequate NPSH, and to indicate the need for flow cross connect. HPI flow is throttled based on RCS pressure, subcooled margin, and pressurizer level. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two HPI trains. The channels provide flow indication over a range of 0 to 750 gpm.

BASES

LCO
(continued)

18. → ~~19.~~ LPI System Flow

LPI System Flow instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements, to prevent LPI pump runout and for flow balance. The indication is also used to identify an LPI pump operating at system pressures above its shutoff head. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two LPI trains. The LPI channels provide flow indication over a range of 0 to 6000 gpm.

19. → 20. Reactor Building Spray Flow

Reactor Building Spray Flow instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements and iodine removal and to prevent Reactor Building Spray and LPI pump runout. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two RBS trains. The channels provide flow indication over a range from 0 to 2000 gpm.

20. → 21. Emergency Feedwater Flow

EFW Flow instrumentation is a Type D, Category 1 variable provided to monitor operation of RCS heat removal via the SGs. Two channels provide indication of EFW Flow to each SG over a range of approximately 100 gpm to 1200 gpm. Redundant monitoring capability is provided by the two independent channels of instrumentation for each SG. Each flow transmitter provides an input to a control room indicator. One channel also provides input to a recorder.

EFW Flow is the primary indication used by the operator to verify that the EFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

BASES

LCO (continued)

21. 22. Low Pressure Service Water (LPSW) flow to LPI Coolers

LPSW flow to LPI Coolers is a Type A, Category 1 variable is provided to prevent LPSW pump runout and inadequate NPSH. LPSW flow to LPI Coolers is throttled to maintain proper flow balance in the LPSW System.

Flow measurement is provided by one channel per train with readout on an indicator and recorder. The channels provide flow indication over a range from 0-8000 gpm.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required to mitigate accidents and transients. The applicable accidents and transients are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event occurring that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 is added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident utilizing alternate instruments and methods, and the low probability of an event requiring these instruments.

Note 2 is added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.8-1. When the Required Channels for a function in Table 3.3.8-1 are specified on a "per" basis (e.g., per loop, per SG, per penetration flow path), then the Condition may be entered separately for each loop, SG, penetration flow path, etc., as appropriate. The Completion Time(s) of the inoperable channels of a Function are tracked separately for each Function starting from the time the Condition is entered for that Function.

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel inoperable, the inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience. This takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

Condition A is modified by a Note indicating this Condition is not applicable to PAM Functions ~~14, 18, 19, 20, and 22.~~ 13, 17, 18, 19, AND 21.

B.1

Required Action B.1 specifies initiation of action described in Specification 5.6.6 that requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability and given the likelihood of unit conditions that would require information provided by this instrumentation. The Completion Time of "Immediately" for Required Action B.1 ensures the requirements of Specification 5.6.6 are initiated.

C.1

When one or more Functions have two required channels inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. ~~This Condition does not apply to the hydrogen monitor channels.~~ The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrumentation action operation and the availability of alternative means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance of qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

BASES

ACTIONS

C.1 (continued)

Condition C is modified by a Note indicating this Condition is not applicable to PAM Functions ~~10, 14, 18, 19, 20, and 22.~~ 13, 17, 18, 19, AND 21.

~~D.1~~

~~When two required hydrogen monitor channels are inoperable, Required Action D.1 requires one channel to be restored to OPERABLE status. This action restores the monitoring capability of the hydrogen monitor. The 72 hour Completion Time is based on the relatively low probability of an event requiring hydrogen monitoring. Continuous operation with two required channels inoperable is not acceptable because alternate indications are not available.~~

~~Condition D is modified by a Note indicating this Condition is only applicable to PAM Function 10.~~

~~E~~ D.1

When one required BWST water level channel is inoperable, Required Action ~~E~~ D.1 requires the channel to be restored to OPERABLE status. The 24 hour Completion Time is based on the relatively low probability of an event requiring BWST water and the availability of the remaining BWST water level channel. Continuous operation with one of the two required channels inoperable is not acceptable because alternate indications are not available. This indication is crucial in determining when the water source for ECCS should be swapped from the BWST to the reactor building sump.

Condition ~~E~~ D is modified by a Note indicating this Condition is only applicable to PAM Function ~~14.~~ 13.

~~F.1~~ E.1

When a flow instrument channel is inoperable, Required Action ~~F.1~~ E.1 requires the affected HPI, LPI, or RBS train to be declared inoperable and the requirements of LCO 3.5.2, LCO 3.5.3, or LCO 3.6.5 apply. For Function ~~22,~~ 21, LPSW flow to LPI coolers, the affected train is the

BASES

ACTIONS E.1 ~~E.1~~ (continued)

associated LPI train. For Function ~~18,~~ 17, HPI flow, an inoperable flow instrument channel causes the affected HPI train's automatic function to be inoperable. The HPI train continues to be manually OPERABLE provided the HPI discharge crossover valves and associated flow instruments are OPERABLE. Therefore, HPI is in a condition where one HPI train is incapable of being automatically actuated but capable of being manually actuated. The required Completion Time for declaring the train(s) inoperable is immediately. Therefore, LCO 3.5.2, LCO 3.5.3, or LCO 3.6.5 is entered immediately, and the Required Actions in the LCOs apply without delay. This action is necessary since there is no alternate flow indication available and these flow indications are key in ensuring each train is capable of performing its function following an accident. HPI, LPI, and RBS train OPERABILITY assumes that the associated PAM flow instrument is OPERABLE because this indication is used to throttle flow during an accident and assure runout limits are not exceeded or to ensure the associated pumps do not exceed NPSH requirements.

Condition ~~F~~ E is modified by a Note indicating this Condition is only applicable to PAM Functions ~~18, 19, 20, and 22.~~ 17, 18, 19, AND 21.

~~G.1~~ F.1

Required Action ~~G.1~~ F.1 directs entry into the appropriate Condition referenced in Table 3.3.8-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action and associated Completion Time of Condition C, D, ~~or E,~~ OR as applicable, Condition ~~G~~ F is entered for that channel and provides for transfer to the appropriate subsequent Condition.

~~H~~ G.1 and ~~H~~ G.2

If the Required Action and associated Completion Time of Conditions C, D ~~or E~~ OR are not met and Table 3.3.8-1 directs entry into Condition ~~H~~ G, the unit must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and MODE 4 within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

G.1

H

D

If the Required Action and associated Completion Time of Condition C, D, or E are not met and Table 3.3.8-1 directs entry into Condition H, alternate means of monitoring the parameter should be applied and the Required Action is not to shut down the unit, but rather to follow the directions of Specification 5.6.6 in the Administrative Controls section of the Technical Specifications. These alternative means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allowed time. The report provided to the NRC should discuss the alternative means used, describe the degree to which the alternative means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

Both the RCS Hot Leg Level and the Reactor Vessel Level are methods of monitoring for inadequate core cooling capability. The subcooled margin monitors (SMM), and core-exit thermocouples (CET) provide an alternate means of monitoring for this purpose. The function of the ICC instrumentation is to increase the ability of the unit operators to diagnose the approach to and recovery from ICC. Additionally, they aid in tracking reactor coolant inventory.

The alternate means of monitoring the Reactor Building Area Radiation (High Range) consist of a combination of installed area radiation monitors and portable instrumentation.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs apply to each PAM instrumentation Function in Table 3.3.8-1 except where indicated.

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 31 days for each required instrumentation channel that is normally energized ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel with a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared with similar unit instruments located throughout the unit. If the radiation monitor uses keep alive sources or check sources OPERABLE from the control room, the CHANNEL CHECK should also note the detector's response to these sources.

Agreement criteria are based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Offscale low current loop channels are, where practical, verified to be reading at the bottom of the range and not failed downscale.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal but more frequent checks of channels during normal operational use of the displays associated with this LCO's required channels.

SR 3.3.8.2 and SR 3.3.8.3

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. This test verifies the channel responds to measured parameters within the necessary range and accuracy.

Note 1 to SR 3.3.8.3 clarifies that the neutron detectors are not required to be tested as part of the CHANNEL CALIBRATION. There is no adjustment that can be made to the detectors. Furthermore, adjustment of the detectors is unnecessary because they are passive devices, with minimal drift. Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration and the monthly axial channel calibration.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2 and SR 3.3.8.3 (continued)

For the Containment Area Radiation instrumentation, a CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr, and a one point calibration check of the detector below 10 R/hr with a gamma source.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD)sensors or Core Exit thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

21

SR 3.3.8.2 is modified by a Note indicating that it is applicable only to Functions 7, ~~10~~ and ~~22~~. SR 3.3.8.3 is modified by Note 2 indicating that it is not applicable to Functions 7, ~~10~~ and ~~22~~. The Frequency of each SR is based on operating experience and is justified by the assumption of the specified calibration interval in the determination of the magnitude of equipment drift.

REFERENCES

1. Duke Power Company letter from Hal B. Tucker to Harold M. Denton (NRC) dated September 28, 1984.

2. UFSAR, Section 7.5.

3. NRC Letter from Helen N. Pastis to H. B. Tucker, "Emergency Response Capability - Conformance to Regulatory Guide 1.97," dated March 15, 1988.

4. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, May 1983.

5. NUREG-0737, "Clarification of TMI Action Plan Requirements," 1980.

6. 10 CFR 50.36.

ENCLOSURE 2

ATTACHMENT B

Replacement Technical Specification and Bases Pages

Page Change Instructions

Remove	Insert
3.3.8-1	3.3.8-1
3.3.8-2	3.3.8-2
3.3.8-3	3.3.8-3
3.3.8-4	3.3.8-4
3.3.8-5	3.3.8-5
B 3.3.8-7	B 3.3.8-7
B 3.3.8-8	B 3.3.8-8
B 3.3.8-9	B 3.3.8-9
B 3.3.8-10	B 3.3.8-10
B 3.3.8-11	B 3.3.8-11
B 3.3.8-12	B 3.3.8-12
B 3.3.8-13	B 3.3.8-13
B 3.3.8-14	B 3.3.8-14
B 3.3.8-15	B 3.3.8-15
B 3.3.8-16	B 3.3.8-16
B 3.3.8-17	B 3.3.8-17
B 3.3.8-18	B 3.3.8-18
B 3.3.8-19	-----

3.3 INSTRUMENTATION

3.3.8 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.8 The PAM instrumentation for each Function in Table 3.3.8-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----NOTES-----

1. LCO 3.0.4 is not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----NOTE----- Not applicable to Functions 13, 17, 18, 19 and 21. ----- One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.6.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. -----------NOTE----------- Not applicable to Functions 13, 17, 18, 19 and 21. ----------------------------- One or more Functions with two required channels inoperable.	C.1 Restore one channel to OPERABLE status.	7 days
D. -----------NOTE----------- Only applicable to Function 13. ----------------------------- One required channel inoperable.	D.1 Restore required channel to OPERABLE status.	24 hours
E. -----------NOTE----------- Only applicable to Functions 17, 18, 19, and 21. ----------------------------- One or more Functions with required channel inoperable.	E.1 Declare the affected train inoperable.	Immediately
F. Required Action and associated Completion Time of Condition C or D not met.	F.1 Enter the Condition referenced in Table 3.3.8-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. As required by Required Action F.1 and referenced in Table 3.3.8-1.	G.1 Be in MODE 3. AND G.2 Be in MODE 4.	12 hours 18 hours
H. As required by Required Action F.1 and referenced in Table 3.3.8-1.	H.1 Initiate action in accordance with Specification 5.6.6.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
These SRs apply to each PAM instrumentation Function in Table 3.3.8-1 except where indicated.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.8.2	---NOTE--- Only applicable to PAM Functions 7 and 21. --- Perform CHANNEL CALIBRATION.	12 months
SR 3.3.8.3	---NOTE--- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. Not applicable to PAM Functions 7 and 21. --- Perform CHANNEL CALIBRATION.	18 months

Table 3.3.8-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION F.1
1.	Wide Range Neutron Flux	2	G
2.	RCS Hot Leg Temperature	2	G
3.	RCS Hot Leg Level	2	H
4.	RCS Pressure (Wide Range)	2	G
5.	Reactor Vessel Head Level	2	H
6.	Containment Sump Water Level (Wide Range)	2	G
7.	Containment Pressure (Wide Range)	2	G
8.	Containment Isolation Valve Position	2 per penetration flow path[a][b][c]	G
9.	Containment Area Radiation (High Range)	2	H
10.	Pressurizer Level	2	G
11.	Steam Generator Water Level	2 per SG	G
12.	Steam Generator Pressure	2 per SG	G
13.	Borated Water Storage Tank Water Level	2	G
14.	Upper Surge Tank Level	2	G
15.	Core Exit Temperature	2 independent sets of 5[d]	G
16.	Subcooling Monitor	2	G
17.	HPI System Flow	1 per train	NA
18.	LPI System Flow	1 per train	NA
19.	Reactor Building Spray Flow	1 per train	NA
20.	Emergency Feedwater Flow	2 per SG	G
21.	Low Pressure Service Water Flow to LPI Coolers	1 per train	NA

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

(c) Position indication requirements apply only to containment isolation valves that are electrically controlled.

(d) The subcooling margin monitor takes the average of the five highest CETs for each of the ICCM trains.

BASES

LCO (continued)

9. Containment Area Radiation (High Range)

Containment Area Radiation (High Range) instrumentation is a Type C, Category 1 variable provided to monitor the potential for significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. The Containment Area Radiation instrumentation consists of two channels (RIA 57 and 58) with readout on two indicators and one channel recorded. The indicated range is 1 to 10^7 R/hr.

10. Pressurizer Level

Pressurizer Level instrumentation is a Type A, Category 1 variable used in combination with other system parameters to determine whether to terminate safety injection (SI), if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition. The Pressurizer Level instrumentation consists of three channels (two for Train A and one for Train B) with two channels indicated and one channel recorded.

(Note: three channels are available only two are required). The indicated range is 0 to 400 inches (11% to 84% level as a percentage of volume).

11. Steam Generator Water Level

Steam Generator Water Level instrumentation is a Type A, Category 1 variable provided to monitor operation of decay heat removal via the SG. The indication of SG level is the extended startup range level instrumentation, covering a span of 0 inches to 388 inches above the lower tubesheet.

The operator relies upon SG level information following an accident (e.g., main steam line break, steam generator tube rupture) to isolate the affected SG to confirm adequate heat sinks for transients and accidents.

The extended startup range Steam Generator Level instrumentation consists of four transmitters (two per SG) that feed four gauges.

BASES

LCO

12. Steam Generator Pressure

Steam Generator Pressure instrumentation is a Type A, Category 1 variable provided to support operator diagnosis of a main steam line break or SG tube rupture accident to identify and isolate the affected SG. In addition, SG pressure is a key parameter used by the operator to evaluate primary-to-secondary heat transfer.

Steam generator pressure measurement is provided by two pressure transmitters per SG. Each instrument channel inputs to the ICCM cabinet that provide safety inputs to two indicators located on the main control board in the control room. One channel per SG also provides input to a recorder located in the control room.

13. Borated Water Storage Tank (BWST) Level

BWST Level instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements, i.e., to determine when to initiate the switch over of the core cooling pump suction from the BWST to sump recirculation. BWST level measurement is provided by three channels with readout on two indicators and one recorder. (Note: three channels are available only two are required). Two of the three channels provide inputs to the ICCM cabinet which provides inputs to qualified indicators on the Control Board. The third channel provides a safety input to a dedicated recorder. The channels provide level indication over a range of 0 to 50 feet (13% to 100% of volume).

14. Upper Surge Tank (UST) Level

Upper Surge Tank Level instrumentation is a Type A, Category 1 variable provided to ensure a water supply for EFW. EFW draws condensate grade suction from the USTs and the Condenser Hotwell.

Two Category 1 instrumentation channels are provided for monitoring UST level. These instrument channels are inputs to corresponding train A and B Inadequate Core Cooling Monitoring (ICCM) system cabinets. The ICCM Train A cabinet provides

BASES

LCO

14. Upper Surge Tank (UST) Level (continued)

UST level input to a dedicated qualified recorder and to a qualified indicator, both located in the Control Room. The ICCM Train B cabinet also provides an input to a qualified indicator located in the Control Room. The range of UST level indication is 0 to 12 feet.

UST Level is the primary indication used by the operator to identify loss of UST volume. The operator can then decide to replenish the UST or align suction to the EFW pumps from the hotwell.

15. Core Exit Temperature

Core Exit Temperature is a Type A, Category 1 variable provided for verification and long term surveillance of core cooling.

The operator relies on this information following a LOCA to secure HPI and throttle LPI, following a SBLOCA to throttle HPI and begin forced HPI cooling if needed, and following a MSLB and SG Tube Rupture to throttle HPI and isolate the affected SG.

There are a total of 52 Core Exit Thermocouples (CETs) per Oconee Unit. Twenty-four (12 per train) meet seismic and environmental qualification requirements (Category 1). The unit computer is the primary display for all 52 CETs. The CETs are distributed to provide monitoring of four or more in each quadrant for each train. The ICCM plasma displays (1 per train) located in the Control Room serve as safety related backup displays for the twenty-four Category 1 CETs. The range of the readouts is 50°F to 2300°F.

The ICCM CET function uses inputs from twelve incore thermocouples per train to calculate and display temperatures of the reactor coolant as it exits the core and to provide indication of thermal conditions across the core at the core exit. Each of the twelve qualified thermocouples per train is displayed on a spatially oriented core map on the plasma display. Trending of CET temperature is available continuously on the plasma display. The average of the five hottest CETs is trendable for the past forty minutes.

BASES

LCO

15. Core Exit Temperature (continued)

An evaluation was made of the minimum number of valid core exit thermocouples (CETs) necessary for inadequate core cooling detection. The evaluation determined the reduced complement of CETs necessary to detect initial core recovery and to trend the ensuing core heatup. The evaluations account for core nonuniformities and cold leg injection. Based on these evaluations, adequate or inadequate core cooling detection is ensured with two sets of five valid CETs.

Table 3.3.8-1 Note (d) indicates that the subcooling margin monitor takes the average of the five highest

CETs for each of the ICCM trains. Two channels ensure that a single failure will not disable the ability to determine the representative core exit temperature.

16. Subcooling Monitor

The Subcooling Monitor is a Type A, Category 1 variable provided for verification and long term surveillance of core cooling. This variable is a computer calculated value using various inputs from the Primary System.

Two channels of indication are provided. An operable Subcooling Monitor shall consist of: 1) One direct indication from one channel for RCS Loop Saturation margin and one direct indication from the other channel for Core Saturation margin, or 2) One direct indication from each of the two channels for RCS Loop Saturation margin. The indication readouts are located in the control room. This variable also inputs to the unit computer through isolation buffers and is available for trend recording upon operator demand. The range of the readouts is 200°F subcooled to 50°F superheat. The control room display is through the ICCM plasma display unit.

A backup method for determining subcooling margin ensures the capability to accurately monitor RCS subcooling margin (Refer to Specification 5.5.17).

BASES

LCO (continued)

17. HPI System Flow

HPI System Flow instrumentation is a Type A, Category 1 variable provided to support action for short term cooling requirements, to prevent HPI pump runout and inadequate NPSH, and to indicate the need for flow cross connect. HPI flow is throttled based on RCS pressure, subcooled margin, and pressurizer level. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two HPI trains. The channels provide flow indication over a range of 0 to 750 gpm.

18. LPI System Flow

LPI System Flow instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements, to prevent LPI pump runout and for flow balance. The indication is also used to identify an LPI pump operating at system pressures above its shutoff head. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two LPI trains. The LPI channels provide flow indication over a range of 0 to 6000 gpm.

19. Reactor Building Spray Flow

Reactor Building Spray Flow instrumentation is a Type A, Category 1 variable provided to support action for long term cooling requirements and iodine removal and to prevent Reactor Building Spray and LPI pump runout. Flow measurement is provided by one channel per train with readout on an indicator and recorder. There are two RBS trains. The channels provide flow indication over a range from 0 to 2000 gpm.

20. Emergency Feedwater Flow

EFW Flow instrumentation is a Type D, Category 1 variable provided to monitor operation of RCS heat removal via the SGs. Two channels provide indication of EFW Flow to each SG over a range of approximately 100 gpm to 1200 gpm. Redundant monitoring capability is provided by the two independent channels of instrumentation for each SG. Each flow transmitter provides an input to a control room indicator. One channel also provides input to a recorder.

BASES

LCO

20. Emergency Feedwater Flow (continued)

EFW Flow is the primary indication used by the operator to verify that the EFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

21. Low Pressure Service Water (LPSW) flow to LPI Coolers

LPSW flow to LPI Coolers is a Type A, Category 1 variable is provided to prevent LPSW pump runout and inadequate NPSH. LPSW flow to LPI Coolers is throttled to maintain proper flow balance in the LPSW System.

Flow measurement is provided by one channel per train with readout on an indicator and recorder. The channels provide flow indication over a range from 0-8000 gpm.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and preplanned actions required to mitigate accidents and transients. The applicable accidents and transients are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event occurring that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 is added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident utilizing alternate instruments and methods, and the low probability of an event requiring these instruments.

BASES

ACTIONS (continued)

Note 2 is added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.8-1. When the Required Channels for a function in Table 3.3.8-1 are specified on a "per" basis (e.g., per loop, per SG, per penetration flow path), then the Condition may be entered separately for each loop, SG, penetration flow path, etc., as appropriate. The Completion Time(s) of the inoperable channels of a Function are tracked separately for each Function starting from the time the Condition is entered for that Function.

A.1

When one or more Functions have one required channel inoperable, the inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience. This takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

Condition A is modified by a Note indicating this Condition is not applicable to PAM Functions 13, 17, 18, 19, and 21.

B.1

Required Action B.1 specifies initiation of action described in Specification 5.6.6 that requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability and given the likelihood of unit conditions that would require information provided by this instrumentation. The Completion Time of "Immediately" for Required Action B.1 ensures the requirements of Specification 5.6.6 are initiated.

BASES

ACTIONS (continued)

C.1

When one or more Functions have two required channels inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrumentation action operation and the availability of alternative means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance of qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

Condition C is modified by a Note indicating this Condition is not applicable to PAM Functions 13, 17, 18, 19, and 21.

D.1

When one required BWST water level channel is inoperable, Required Action D.1 requires the channel to be restored to OPERABLE status. The 24 hour Completion Time is based on the relatively low probability of an event requiring BWST water and the availability of the remaining BWST water level channel. Continuous operation with one of the two required channels inoperable is not acceptable because alternate indications are not available. This indication is crucial in determining when the water source for ECCS should be swapped from the BWST to the reactor building sump.

Condition D is modified by a Note indicating this Condition is only applicable to PAM Function 13.

E.1

When a flow instrument channel is inoperable, Required Action E.1 requires the affected HPI, LPI, or RBS train to be declared inoperable and the requirements of LCO 3.5.2, LCO 3.5.3, or LCO 3.6.5 apply. For Function 21, LPSW flow to LPI coolers, the affected train is the

BASES

ACTIONS

E.1 (continued)

associated LPI train. For Function 17, HPI flow, an inoperable flow instrument channel causes the affected HPI train's automatic function to be inoperable. The HPI train continues to be manually OPERABLE provided the HPI discharge crossover valves and associated flow instruments are OPERABLE. Therefore, HPI is in a condition where one HPI train is incapable of being automatically actuated but capable of being manually actuated. The required Completion Time for declaring the train(s) inoperable is immediately. Therefore, LCO 3.5.2, LCO 3.5.3, or LCO 3.6.5 is entered immediately, and the Required Actions in the LCOs apply without delay. This action is necessary since there is no alternate flow indication available and these flow indications are key in ensuring each train is capable of performing its function following an accident. HPI, LPI, and RBS train OPERABILITY assumes that the associated PAM flow instrument is OPERABLE because this indication is used to throttle flow during an accident and assure runout limits are not exceeded or to ensure the associated pumps do not exceed NPSH requirements.

Condition E is modified by a Note indicating this Condition is only applicable to PAM Functions 17, 18, 19, and 21.

F.1

Required Action F.1 directs entry into the appropriate Condition referenced in Table 3.3.8-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met the Required Action and associated Completion Time of Condition C or D, as applicable, Condition F is entered for that channel and provides for transfer to the appropriate subsequent Condition.

G.1 and G.2

If the Required Action and associated Completion Time of Conditions C or D are not met and Table 3.3.8-1 directs entry into Condition G, the unit must be brought to a MODE in which the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and MODE 4 within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

H.1

If the Required Action and associated Completion Time of Condition C or D are not met and Table 3.3.8-1 directs entry into Condition H, alternate means of monitoring the parameter should be applied and the Required Action is not to shut down the unit, but rather to follow the directions of Specification 5.6.6 in the Administrative Controls section of the Technical Specifications. These alternative means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allowed time. The report provided to the NRC should discuss the alternative means used, describe the degree to which the alternative means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

Both the RCS Hot Leg Level and the Reactor Vessel Level are methods of monitoring for inadequate core cooling capability. The subcooled margin monitors (SMM), and core-exit thermocouples (CET) provide an alternate means of monitoring for this purpose. The function of the ICC instrumentation is to increase the ability of the unit operators to diagnose the approach to and recovery from ICC. Additionally, they aid in tracking reactor coolant inventory.

The alternate means of monitoring the Reactor Building Area Radiation (High Range) consist of a combination of installed area radiation monitors and portable instrumentation.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs apply to each PAM instrumentation Function in Table 3.3.8-1 except where indicated.

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 31 days for each required instrumentation channel that is normally energized ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel with a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; therefore, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared with similar unit instruments located throughout the unit. If the radiation monitor uses keep alive sources or check sources OPERABLE from the control room, the CHANNEL CHECK should also note the detector's response to these sources.

Agreement criteria are based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are off scale in the same direction. Offscale low current loop channels are, where practical, verified to be reading at the bottom of the range and not failed downscale.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal but more frequent checks of channels during normal operational use of the displays associated with this LCO's required channels.

SR 3.3.8.2 and SR 3.3.8.3

A CHANNEL CALIBRATION is a complete check of the instrument channel, including the sensor. This test verifies the channel responds to measured parameters within the necessary range and accuracy.

Note 1 to SR 3.3.8.3 clarifies that the neutron detectors are not required to be tested as part of the CHANNEL CALIBRATION. There is no adjustment that can be made to the detectors. Furthermore, adjustment of the detectors is unnecessary because they are passive devices, with minimal drift. Slow changes in detector sensitivity are compensated for by performing the daily calorimetric calibration and the monthly axial channel calibration.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2 and SR 3.3.8.3 (continued)

For the Containment Area Radiation instrumentation, a CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr, and a one point calibration check of the detector below 10 R/hr with a gamma source.

Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the resistance temperature detectors (RTD)sensors or Core Exit thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

SR 3.3.8.2 is modified by a Note indicating that it is applicable only to Functions 7 and 21. SR 3.3.8.3 is modified by Note 2 indicating that it is not applicable to Functions 7 and 21. The Frequency of each SR is based on operating experience and is justified by the assumption of the specified calibration interval in the determination of the magnitude of equipment drift.

REFERENCES

1. Duke Power Company letter from Hal B. Tucker to Harold M. Denton (NRC) dated September 28, 1984.
2. UFSAR, Section 7.5.
3. NRC Letter from Helen N. Pastis to H. B. Tucker, "Emergency Response Capability - Conformance to Regulatory Guide 1.97," dated March 15, 1988.
4. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3, May 1983.
5. NUREG-0737, "Clarification of TMI Action Plan Requirements," 1980.
6. 10 CFR 50.36.

ENCLOSURE 2

ATTACHMENT C

Description and Technical Justification of Proposed Changes

This is a request to revise the Oconee Nuclear Station, Units 1, 2, and 3 (ONS) Technical Specification (TS) 3.3.8, "Post Accident Monitoring (PAM) Instrumentation," and the associated TS Bases. Additionally, Selected Licensee Commitment (SLC), 16.6.10, " Containment Hydrogen Recombiner System," would be deleted during implementation of this license amendment request. Other changes described below would be implemented on approval of the exemption request provided in Enclosure 1 and this license amendment application.

1.0 DESCRIPTION OF CHANGES

TS 3.3.8, "Post Accident Monitoring (PAM) Instrumentation," would be revised by deletion of Item 10, Containment Hydrogen Concentration monitors from Table 3.3.8-1 and renumbering the existing Items 11 through 22 to 10 through 21. Additionally, the existing Condition D would be deleted and the subsequent Conditions (E through I) would be redesignated as D through H. The related changes include:

- Deleting references to the existing Table 3.3.8-1, Item 10 in the Note for Condition C and in Surveillance Requirement (SR) 3.3.8.2 and 3.3.8.3.
- The Notes to Conditions A, C, the redesignated E, and SR 3.3.8.2 and 3.3.8.3 would be modified to reflect the above described renumbering of the existing Table 3.3.8-1 Items 11 through 22 to 10 through 21.
- The Table 3.3.8-1 column heading "CONDITIONS REFERENCED FROM REQUIRED ACTION G.1" is revised to refer to Required Action F.1. The Conditions listed in this column are revised to reflect the redesignation of Conditions H and I to G and H respectively.
- The designation of Conditions and Required Actions E through I are revised to D through H, and the references to the associated Table 3.3.8-1 Functions are revised to reflect the renumbering of the existing items 11 through 22 to 10 through 21.

The TS 3.3.8 Bases would be revised to correspond to the above TS 3.3.8 changes. A markup of the complete TS 3.3.8 and its Bases is provided in Attachment A to this enclosure. Replacement pages are provided in Attachment B.

On approval of the exemption request and this amendment application, Duke will implement the following Updated Final Safety Analysis (UFSAR) changes (for reviewer convenience these sections are provided in the noted attachments to this enclosure):

- Delete Selected Licensee Commitment (SLC) 16.6.10, Containment Hydrogen Recombiner System," in its entirety. (SLCs are Chapter 16 of the UFSAR. See Attachment C-1).

- UFSAR § 6.5.3, Fission Product Control Systems (Attachment C-2) will be deleted. This UFSAR section identifies that credit is taken for the hydrogen recombiner system as a fission product control system (i.e., a 10 CFR 50, Appendix A, General Design Criteria 41 system).

- UFSAR discussions pertaining to hydrogen monitoring in UFSAR § 7.5.2.10 and § 9.3.7 (Attachment C-3) will be deleted. Other changes will be made as needed to conform the UFSAR to the removal of the hydrogen monitoring and recombiner systems.

- UFSAR § 15.16, Post-accident Hydrogen Control (Attachment C-4) will be revised to remove all references to hydrogen monitoring and recombination, and the potential effects of hydrogen combustion on the Reactor Building (containment). This revision would also include removal of the related tables and figures from UFSAR § 15.16.

Furthermore, after NRC approval of the requested TS changes, Duke will be authorized to make the following changes without further approval:

1. Abandon, change or remove the existing Oconee containment Post-Accident Hydrogen Control System per 10 CFR 50.59.

2. Duke will be released from commitments regarding the Oconee Combustible Gas Control System. As such the consideration of post-accident hydrogen generation will no longer be included in the Oconee design basis.

3. Revise the Oconee Emergency Classification Procedure (RP/0/B/1000/001), Enclosure 4.1 (Fission Product Barrier Matrix), to delete the reference to hydrogen concentration ≥ 9% being a potential loss of containment isolation. Additionally, the Duke Power Company, Oconee Nuclear Station, Emergency Plan, Volume A, Section D (Emergency Classification System), would be revised to delete all references to containment hydrogen concentration. Training plans and documents would be revised with implementation of these changes.

2.0 TECHNICAL JUSTIFICATION FOR CHANGES

The technical justification for the above requested license changes is provided in Enclosure 1 (Exemption Request), Section 2.0 (Technical Justification) of this submittal.

3.0 ATTACHMENTS

C-1 Selected Licensee Commitment 16.6.10, "Containment Recombiner System."

C-2 UFSAR § 6.5.3, "Fission Product Control Systems."

C-3 UFSAR § 7.5.2.10 and § 9.3.7 concerning containment hydrogen monitoring.

C-4 UFSAR § 15.16, "Post-accident Hydrogen Control."

ENCLOSURE 2

Attachment C-1

Selected Licensee Commitment 16.6.10,
"Containment Recombiner System"

16.6 ENGINEERED SAFETY FEATURES

16.6.10 Containment Hydrogen Recombiner System

COMMITMENT The Containment Hydrogen Recombiner System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Hydrogen Recombiner System inoperable.	A.1 Restore to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 16.6.10.1	Verify the post-LOCA flow path by connecting and operating the Hydrogen Recombiner through its flow path. The Hydrogen Recombiner flow path shall circulate Reactor Building atmosphere at a flow > 50 SCFM.	-----------NOTE----------- The provisions of SLC 16.2.7 do not apply. ---------------------------- 18 months +25%

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 16.6.10.2	Visual inspection of the hydrogen recombiner unit.	------------NOTE----------- The provisions of SLC 16.2.7 do not apply. ------------------------------- 18 months +25%
SR 16.6.10.3	CHANNEL CALIBRATION of recombiner instrumentation channels.	------------NOTE----------- The provisions of SLC 16.2.7 do not apply. ------------------------------- 18 months +25%
SR 16.6.10.4	Operate a recombiner unit at design flow rate ± 10% and allow unit to reach recombination temperature.	------------NOTE----------- The provisions of SLC 16.2.7 do not apply. ------------------------------- 18 months +25%

BASES

The requirement(s) of this SLC section were relocated from CTS 3.16.1 and 4.4.3 during the conversion to ITS.

The Containment Hydrogen Recombiner System shall be OPERABLE in MODES 1, 2, 3 and 4. The Recombiner System consists of one OPERABLE hydrogen recombiner unit available for connection to the associated flow path for each Oconee unit.

The Containment Hydrogen Recombiner System is required at approximately 7 days following a LOCA to limit hydrogen concentration to 4.0 percent by volume.

The Containment Hydrogen Recombiner System is utilized to maintain the post-accident containment atmosphere hydrogen concentration below its lower flammability limit of 4.0 percent by volume. The Containment Hydrogen Recombiner System includes a portable hydrogen recombiner which will be moved to the affected unit following a LOCA, anchored to its

foundation, and connected to piping penetrations. Also included is a portable control panel, which will be locally mounted near the recombiner, anchored to its foundation and connected to its motor control center and the recombiner.

The control panel mounted near the recombiner enables the operator to control and monitor system parameters for all functions of the recombiner system except containment isolation valve operation. The control and monitor functions include: process temperature indications, temperature control, flow indication, start/stop switch, low temperature timer and various annunciators. Therefore, the operational performance testing ensures operability.

The penetrations to and from the hydrogen recombiner are shared with the gaseous radiation monitoring pump. Since this pump is normally in operation and since there is no system isolation valve on the supply branch to the recombiner, the blind flanges are the only means of system isolation.

Therefore, these flange joints shall be leak tested after each removal and installation to ensure adequate isolation.

The hydrogen recombiner unit operational performance test should be conducted with full flow and with the heaters energized. The capability of the recombiner to achieve the required recombination temperature and flow rate is considered an adequate test of recombination efficiency. Gas inlet and outlet sampling is not required.

REFERENCE

UFSAR, Section 15.16

ENCLOSURE 2

Attachment C-2

UFSAR § 6.5.3,
"Fission Product Control Systems."

6.5.1.6 Materials

Carbon steel and suitable coatings are used to obtain desired service life.

6.5.2 CONTAINMENT SPRAY SYSTEMS

4 No credit is taken for this system for fission product removal or control in LOCA analysis (see 15.14.7,
4 "Environmental Evaluation"). Credit is taken for this system for fission product removal in the MHA
4 off-site dose analyses only. (see 15.15.1, "Identification of Accident").

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

5 Credit is taken for fission product control by the Containment Hydrogen Recombiner System which is
5 addressed in Section 15.16, "Post-Accident Hydrogen Control"; however, this system is not considered an
5 Engineered Safeguards System.

ENCLOSURE 2

Attachment C-3

UFSAR § 7.5.2.10, and § 9.3.7
concerning containment hydrogen monitoring

2 buffers provided by the ICCM. Two non-qualified transmitters, one per train, also provide non-safety
2 inputs to the OAC.

2 LPI System is a Type A variable at Oconee because the operator relies on this information following a
3 design basis event (LOCA, SB LOCA) to throttle LPI flow.

2 (RE: NSMs ON-1/2/32587)

2 7.5.2.9 Reactor Building Spray Flow

2 Two QA Condition 1 instrumentation channels are provided for post accident monitoring Reactor
2 Building Spray flow in response to Regulatory Guide 1.97. Each instrumentation channel is seismically
2 and environmentally qualified and powered from a safety grade source. Each instrument channel signal,
2 train A and B respectively, inputs to a qualified indicator and qualified recorder via the inadequate core
2 cooling monitoring (ICCM) cabinets. These channels monitor Reactor Building Spray flow over the
2 range 0-2000 gpm which envelopes the Regulatory Guide 1.97 range requirement of 0-110% of design
2 flow.

2 The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC), annunciator,
2 and a non-safety indicator located in the Control Room. Safety train integrity is maintained through the
2 use of isolation buffers provided by the ICCM system. Also provided is two non-safety instrument
2 channels which provide non-safety inputs to the OAC.

2 RBS Flow is a Type A variable at Oconee because the operator relies on this information following a
3 design basis event (LOCA, SB LOCA) to throttle RBS flow.

2 (RE: NSMs ON-1/2/32588)

2 7.5.2.10 Reactor Building Hydrogen Concentration

2 Two redundant channels of nuclear safety related instrumentation monitor reactor building hydrogen
2 concentration. The indicated range is from 0 to 10% concentration which envelopes the Regulatory
2 Guide 1.97 range requirements.

2 Both channels are powered by safety grade emergency buses. Control of the sample line switching valves
2 and sample selector solenoid valves is accomplished at the analyzer remote control panel. These
2 instruments are seismically and environmentally qualified. (RE: FSAR 9.3.7, "Containment Hydrogen
2 Monitoring System")

2 7.5.2.11 Upper Surge Tank and Hotwell Level

2 Oconee's Emergency Feedwater System (EFDW) draws condensate grade suction from the Upper Surge
2 Tanks and the Condenser Hotwell. Condensate may also be provided from the Condensate Storage Tank
2 (CST) and the Makeup Demineralizers. Additional backup of the two normal condensate sources is
2 provided by these same locations associated with the other two units. The level transmitters which
2 monitor Upper Surge Tank and Hotwell level are located in the Turbine building which is a mild
2 environment.

2 Category 3 instrumentation is available to monitor Hotwell level in the Control Room. One continuous
2 recorder and computer monitoring point is provided to monitor this variable.

The operator can complete the sampling sequence in 30 to 60 minutes. The combined time allotted for sampling and analysis will be well within 3 hours from the time a decision has been made to take a sample. Alternate power sources are provided to meet the 3-hour limit in case of a loss of off-site power.

9.3.6.2.3 Mode of Operation

The operation of the Post-Accident Containment Air Sampling System is sequenced as follows:

1. The Post-Accident Containment Sampling System isolates a known quantity of containment
8 atmosphere, moves this quantity through a particulate air filter and an activated charcoal cartridge for separation of iodine and particulates from the noble gases, and provides a sample of the diluted gas for analysis.
2. Dilution gas (nitrogen) is provided for dilution factor up to 10,000 to 1.
8 3. The sampling system flushes and purges all interior sample lines as soon as possible to reduce
8 personnel exposure dose rates.

9.3.7 CONTAINMENT HYDROGEN MONITORING SYSTEM

9.3.7.1 Design Bases

The containment Hydrogen Monitoring System provides continuous indication of hydrogen concentration in the containment atmosphere. The measurement capability is provided over the range of 0% to 10% hydrogen concentration under both positive and negative ambient pressures. A continuous indication of the hydrogen concentration is not required in the control room at all times during normal operation. If continuous indication of the hydrogen concentration is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of the safety injection.

9.3.7.2 System Description

The Containment Hydrogen Monitor System withdraws a sample from the containment under normal, LOCA or Post LOCA conditions. The sample is analysed and returned to the containment. The monitoring system is designed to monitor containment gas for percentage volume of hydrogen.

A system of sample taking tubing is installed in the containment to draw air samples from 5 different levels or areas. Each of the sample intake lines has a solenoid valve which is remotely operated from a control panel in the ventilation room. At the control panel a selector solenoid valve is used to provide air flow to the Hydrogen Analyser from the selected intake port. The Hydrogen Analyser panels and associated remote control panels are located in the ventilation room. Remote alarm and indication is provided in the control room. There are two trains of equipment for each unit.

Ten Hydrogen Analyzer intake ports are installed, (two each) in the following locations:

1. The top of the Containment Building Dome, Elevation 983′ ± 5″
2. The operational level as close to the vessel as practical, Elevation 844 + 0′ ± 10′
3. The basement area, Elevation 788′ + 0″ ± 10′
4. The radiation monitor/hydrogen recombiner inlet header, Elevation 827′ + 4″
5. The radiation monitor/hydrogen recombiner outlet header, Elevation 824′ + 0″

<u>Hydrogen Measurement</u>

Analysis is accomplished by using the well established principle of thermal conductivity measurements of gases. This technique utilizes a self-heating filament fixed in the center of a temperature-controlled metal cavity. The filament temperature is determined by the amount of heat conducted by the presence of gas from the filament of the cavity walls. Thermal conductivity varies with gas species, thereby causing the filament temperature to change as the gas in the cavity changes. Filament resistance changes with temperature therefore, by using two filaments in separate cavities and connecting them in an electrical bridge, the difference in thermal conductivity of gases in the separate cavities may be determined electrically.

Electrical zero is set by first introducing the same gas to both cavities, then adjusting the electrical bridge to balance, resulting in a zero output. As different gases are introduced to the two individual cavities, the bridge will become unbalanced, and the electrical output will amplify with increasing differences in thermal conductivity of the gases used.

The measurement of hydrogen in the presence of nitrogen, oxygen and water vapor is possible because the thermal conductivity of hydrogen is approximately seven times higher than nitrogen, oxygen or water vapor, which have nearly the same thermal conductivities (at the filament operational temperature of approximately 550°K). The measurement is accomplished by using a thermal conductivity measurement cell and a catalytic reactor. The sample first flows through the reference section of the cell, then passes through the sample section of the measuring cell that includes the catalyst. The catalyst is chosen so that post-LOCA iodine will not poison the catalyst bed. The change in sample composition, due to the catalytic reaction is therefore indicated by the difference in thermal conductivity of the sample hydrogen content, as measured in the sample and reference sides of the cell.

If an excess amount of oxygen does not exist in the sample for recombining all the hydrogen, oxygen can be provided ahead of the hydrogen analyzer. The amount of oxygen added is determined by the highest range of the analyzer.

Alarms

Alarms are provided for high hydrogen concentration, cell failure and loss of power. These alarms are available on the analyzer itself and as signals to the control room annunciator. Additional alarms on the analyzer itself include low instrument temperature, low sample flow, low gas pressure and common failure.

9.3.7.3 Safety Evaluation

The Containment Hydrogen Monitor System (CHMS) meets the requirements of NUREG-0737, Item II.F.1.6. The CHMS has both indicator and recorder readouts in the control room on one of the two redundant channels and a indicator readout on the second channel. The CHMS has a range of 0% to
7 10% of Hydrogen. The CHMS indicator loop has a system accuracy of 3.0% of the full scale. The CHMS hardwired recorder loop and all the CHMS plant process computer loops have a system accuracy of 2.6% of the full scale. These values will provide information over the intended range of the CHMS that is sufficiently accurate and useful to allow the plant operator to adequately assess the hydrogen concentration within containment. There are five ports to draw samples for each of the redundant hydrogen monitors. The system provides capability to rapidly detect Hydrogen from the reactor and determine its concentration throughout the containment.

ENCLOSURE 2

Attachment C-4

UFSAR § 15.16,
"Post-accident Hydrogen Control."

1 15.16 POST-ACCIDENT HYDROGEN CONTROL

1 15.16.1 INTRODUCTION

5 The purpose of this section is to summarize the analyses performed to:

5 1. Evaluate the hazard caused by hydrogen generation following a LOCA.

5 2. Evaluate the acceptability of hydrogen recombination as a method for controlling the Reactor
5 Building hydrogen concentration.

5 In this section the potential for radiolytic hydrogen generation including the dose, or energy deposited in
5 the coolant following the accident, and the basis for the selection of the hydrogen generation constant
5 ("G" value) is analyzed. Since the FSAR analyzes the potential zircaloy-water reaction in other sections,
5 this analysis is not presented herein and a 5 percent zirc-water reaction is assumed in the reference case
5 described in subsequent sections. The potential for hydrogen generation from a zinc-boric acid reaction
5 when borated water spray solution contacts galvanized steel and aluminum in the Reactor Building at the
5 post-accident temperature is also considered. The analysis shows that the radiolytic hydrogen generation
5 rate plus the hydrogen contributed by the zircaloy and other reactions does not result in unacceptable
7 hydrogen concentrations until 310 hr after the initiation of the LOCA.

5 Post-accident Reactor Building hydrogen concentration is controlled by the use of the Thermal Hydrogen
5 Recombiner. Air is drawn from the reactor building at a flow of greater than 50 scfm to the recombiner.
5 There the air is heated to approximately 1340 deg. F and passed through a reaction chamber causing
5 hydrogen and oxygen molecules to recombine into water vapor. The effluent from this process then flows
5 back to the reactor building. Since all process gas is returned to the reactor building, no release of
5 radioactive material is made to the environment and therefore the hydrogen concentration can be reduced
5 without increasing the radiation dose to the public.

5 Regulatory Guide 1.7 "Control of Combustible Gas Concentrations in Containment Following a
5 Loss-of-Coolant Accident" has been referenced in several sections of this analysis. Even though the
5 Regulatory Guide has been used for guidance and information, Oconee is not committed to Regulatory
5 Guide 1.7.

1 15.16.2 POST-ACCIDENT HYDROGEN GENERATION

1 15.16.2.1 Radiolytic Hydrogen Generation

1 15.16.2.1.1 Sources of Radiation

5 The radiation sources which contribute to the energy absorbed by the coolant following an accident are
5 shown in Table 15-17. For the LOCA the only significant amount of radiation comes from sources in
5 and near the core. In addition to the core sources, the contributions from the gases in the Reactor
5 Building atmosphere, and the fission products in the coolant water itself are also considered. Table 15-18
5 shows the assumption used in the calculation of the energy deposited in the solution described in the
5 following section.

5 Figure 15-82 shows the flow path of the post-accident ECCS in the long-term recirculation mode.
5 Following a LOCA, the fluid for the RBSS and the ECCS is supplied from the borated water storage tank

5 (BWST). After the BWST is empty, coolant is then circulated from the Reactor Building sump through
5 the LPIS to the reactor vessel.

5 The activity levels of the individual fission product nuclides were determined with B&W's proprietary
5 digital fission product code. This digital code computes the activity of more than 200 fission product
5 nuclides from one or two fissionable materials as a function of reactor operating history. One hundred
5 time steps can be used in the code, and at each time step the program will print the individual nuclide
5 activity along with the total gamma source strengths from all nuclides for each of six gamma energy
5 groups.

5 The activity of the Np-239 and U-239 was obtained using the maximum neutron capture rates that occur
5 in U-238 at any time during a core cycle. Sources from the activated clad and structural materials were
5 calculated assuming saturation activity of these components and using lifetime average neutron fluxes in
5 the core.

1 **15.16.2.1.2 Calculation of Absorbed Energy**

5 Table 15-18 summarizes the assumption made in calculating the energy absorbed by the coolant. In a
5 LOCA all of the absorbed energy comes from sources in and near the core with the greatest fraction
5 coming from fission product decay. The energy from fission product decay is about equally divided
5 between gamma rays and beta particles. To determine the energy deposited in the solution by beta
5 particles, the fuel pellets were subdivided into concentric cylindrical source shells, 10 mils in thickness.
5 The amount of beta energy that was transmitted through the fuel cladding was calculated for each of these
5 source shells. These calculations were performed for each fission product nuclide. It was assumed that all
5 of the energy that penetrated the clad was absorbed by the water. The integrated beta energy between 10
5 and 3,000 hr after the LOCA was only two to three percent of that from the gamma rays. Nearly all of
5 the beta energy is absorbed by the oxide and cladding.

5 For gamma rays the fission product source strengths were taken from the output of the fission product
5 code and the gamma sources from U-239 and Np-239 were added to the various energy groups to obtain
5 the total core source strengths. Energy deposition rates to the solution at various times were then
5 calculated for each of the six gamma energy groups. Since these sources contribute most of the energy
5 received by the solution, this calculation was checked using three techniques, all based on the assumption
5 of a homogeneous core with a uniform average source distribution.

5 First, the amount of energy produced per unit volume of core was assumed to equal the amount of energy
5 absorbed per unit volume. The distribution of absorbed energy between the cooling water and the
5 remainder of the core was found by a ratio of the energy absorption coefficient of water to that of the
5 homogenized core for each of the energy groups. In the second technique a receiver point was chosen at
5 the center of the core. The energy absorption rate was calculated at this location with a point kernel
5 integration code. The absorption at all other points in the core was assumed to be in the same as that at
5 this point. For the third calculation the core was represented as an infinite homogeneous medium and the
5 flux equations for an infinite slab were used to calculate the absorbed energy. These latter two
5 calculations require the use of energy absorption buildup parameters for the homogenized core. A
5 comparison between the mass and energy absorption coefficients for the core with those of various
5 materials showed that the coefficients for lead matched those of the core quite well. The energy
5 absorption buildup factors for lead were thus incorporated into the flux equations using the Taylor form
5 of the buildup.

5 The total energy deposited in the solution was obtained by graphical integration of the absorption rate
5 curves. Figure 15-84 shows the energy absorbed by the solution as a function of time following the
5 LOCA. The results have been presented in terms of the energy absorbed by the solution rather than in
5 dose units. The reason is that dose is a measure Absorbed Energy of energy absorbed per unit mass of

5 material. Consequently, whenever the volume or mass of the emergency core cooling solution changes,
5 the dose changes. The generation of hydrogen, however, is a function only of the energy absorbed by the
5 solution and does not change simply because the mass of the solution changes.

5 The curve shown in Figure 15-84 includes all the sources previously mentioned, fission product gammas,
5 fission product betas, Np-239 and U-239, and activated structural materials. Also included is the energy
5 absorbed by the water outside the core from sources inside core. This was determined by computing the
5 spatial variation of the gamma fluxes in the water outside the core and integrating over the water volume.
5 This contributed between 3 and 4 percent of the total energy absorbed. The activated cladding and other
5 core hardware sources yield deposited energy which is only a fraction of a percent of that from other
5 sources. The greatest amount of absorbed energy comes from the fission product and Np-239 gamma
5 rays; these contribute approximately 95 percent of the total energy.

5 In addition to the core sources, 100 percent of the noble gases in the Reactor Building atmosphere, 50
5 percent of the halogens and 1 percent of the solids in the cooling water must also be considered.

5 In the Reactor Building atmosphere the activity levels and beta and gamma yield data for the noble gases
5 were used to compute the individual beta and gamma source strengths for each nuclide. These sources
5 were distributed uniformly throughout the free air volume of the Reactor Building. For beta particles the
5 energy absorbed per unit volume of air was assumed to be equivalent to that produced per unit volume.
5 For gamma rays the absorbed energy was computed at a point in the center of the Reactor Building and
5 it was assumed that all other points in the building received this same energy. The gamma flux was
5 calculated with a point kernel integration code. No credit was taken for attenuation by shielding by
5 structures within the Reactor Building.

5 For the 50 percent halogens and 1 percent solid fission products in the cooling water, it was assumed that
5 all of the energy produced by these sources was absorbed in the water. The absorbed energy from the
5 halogens was computed for each nuclide using the individual beta and gamma yields. The contribution
5 from the 1 percent solids was obtained by taking 1 percent of the total fission product decay heat curve
5 and depositing this quantity of energy to the coolant.

5 As can be seen in Figure 15-84, initially the energy is controlled by the fission products in the cooling
5 water. However, by 100 hr the sources in the core have taken over and continue to control as time
5 increases. The contribution from the noble gases in the building atmosphere does not show up on the
5 graph - this was insignificant in comparison to the other sources.

5 Since the core sources, and in particular the fission product gammas, contribute most of the energy to the
5 solution, a comparison has been made between the decay heat gamma sources calculated by B&W with
5 that published by Shure (Reference 1). Figure 15-85 shows the integrated gamma decay heat (fission
5 products plus U-239 and Np-239) between 10 and 3,000 hr decay time following 620 days irradiation time
5 from the two methods. Over the time span of interest for hydrogen generation (100 - 1,000 hr), they are
5 in excellent agreement.

5 **15.16.2.1.3 Radiolytic Hydrogen Generation**

5 The hydrogen generation rates from the radiolytic decomposition of water were calculated utilizing the
5 data presented in Figure 15-84 and a hydrogen generation constant ("G" value) equal to 0.45 molecules of
5 hydrogen per 100 ev of energy absorbed by the fluid in the core region.

5 In the LOCA the integrated energy absorption by the sump solution is small, and this has been lumped
5 with the core energy and a single hydrogen generation constant has been used. Under the Design Basis
5 Accident (DBA) conditions, when the energy absorption in the sump region is significant, as a result of
5 the assumed sources, a "G" value of 0.3 molecules of hydrogen per 100 ev of energy absorbed was used to

5 establish the sump contribution. Both of these hydrogen generation constants are those reported in the
5 literature. The "G" value of 0.45 is used in the core region and is reported as a conservative upper limit for
5 boiling solutions (Reference 2, Reference 3). The "G" value of 0.3 is used for the coolant in the sump
5 which represents a slowly moving fluid and it is based upon published ORNL data (Reference 4).

1 15.16.2.2 Chemical Hydrogen Generation

5 In addition to the radiolytic hydrogen generation sources (core and sump radiolysis) following a Design
5 Basis Accident, hydrogen may also be evolved from two chemical sources: (1) zirconium-water reaction
5 involving clad material, and (2) from the reaction of zinc and aluminum within the Reactor Building with
5 the borated coolant water.

5 15.16.2.2.1 Method of Analysis

5 The quantity of zirconium which reacts with the core cooling solution depends on the performance of the
5 Emergency Core Cooling System. The 10CFR50.46 criteria for evaluation of the Emergency Core
5 Cooling System requires that the zircalloy-water reaction be limited to one percent by weight of the total
5 quantity in the core.

5 Aluminum is more reactive with the Reactor Building spray solution than other plant materials such as
5 galvanized steel, copper, and copper-nickle alloys. However, because of the relatively large amount of
5 exposed galvanized and zinc-based painted surfaces in the Reactor Building, zinc corrosion must be
5 considered as a contributing hydrogen source.

5 It should be noted that zirconium-water reaction and the aluminum and zinc corrosion with Reactor
5 Building spray are chemical reactions and thus essentially independent of the radiation field inside the
5 Reactor Building following a LOCA. Radiolytic decomposition of water is dependent on the radiation
5 field intensity. The radiation field inside the Reactor Building is calculated for the maximum credible
5 accident in which the fission product activities given in TID-14844 are used.

5 15.16.2.2.2 Typical Assumptions

5 The following discussion outlines the assumptions used in the calculations.

5 15.16.2.2.3 Zirconium-water Reaction

5 Hydrogen can be generated during a LOCA by the reaction of hot zirconium cladding with the
5 surrounding steam. The zirconium-water reaction is described by the chemical equation:

5 $$Zr + 2H_2O \text{ ------> } ZrO_2 + 2H_2 + \text{Heat}$$

5 The quantity of zirconium which reacts with the core cooling solution depends on the performance of the
5 Emergency Core Cooling System (ECCS). The 10CFR50.46 criteria for evaluation of the ECCS requires
5 that the zirconium-water reaction be limited to one percent by weight of the total quantity of zirconium in
5 the core. For Oconee the maximum of 1% zirconium-water reaction is assumed. Regulatory Guide 1.7
5 requires that the assumption for hydrogen produced from the zirconium-water reaction equal 5 times the
5 extent of the maximum calculated reaction under 10CFR50.46, i.e., 5.0%. Per Regulatory Guide 1.7, the
5 zirconium-water hydrogen source is assumed to be released over a 2 minute period from the start of the
5 transient, and is assumed to be distributed uniformly throughout Containment.

5 *15.16.2.2.3.1 Corrosion of Plant Materials*

5 Another possible source of hydrogen could occur from metal surfaces exposed to an environment
5 containing high-temperature steam, corrosive sprays, fission products, and radioactivity. Such exposure
5 might result in surface corrosion reactions that produce hydrogen. Corrosive tests have been performed to
5 determine the behavior of various metals that are used in Containment when exposed to a post-LOCA
5 environment. As applied to the quantitative definition of hydrogen production rates, the results of the
5 corrosion tests have shown that only aluminum will corrode at a rate that will significantly add to the
5 hydrogen accumulation in the Containment atmosphere. However, because of the relatively large amount
5 of exposed galvanized and zinc-based painted surfaces in Containment, zinc corrosion must be considered
5 as a contributing hydrogen source.

5 The corrosion of aluminum and zinc may be described by the following reactions:

5 $$2Al + 3H_2O \text{ -----> } Al_2O_3 + 3H_2$$
5 $$Zn + H_20 \text{ -----> } ZnO + H_2$$

5 The time-temperature cycle considered in the calculation of aluminum and zinc corrosion are based on a
5 conservative representation of the postulated post accident Containment transient. The corrosion data
5 points include the effects of temperature, alloy, and spray solution conditions. NOTE: In Section 5, Part
5 C of Regulatory Guide 1.7 it is stated that values given in Table 1 for evaluating production of
5 combustible gases following a LOCA may be changed on the basis of additional experimental evidence
5 and analyses. As a result the minimum assumed value give for aluminum corrosion rate of 200 mpy is
5 not used in the analysis.

5 15.16.2.3 Primary Coolant Hydrogen

5 The maximum equilibrium quantity of hydrogen in the primary coolant is 472 scf. This value includes
5 both hydrogen dissolved in the coolant water at 15-40 cc (STP) per liter of water and corresponding
5 equilibrium hydrogen in the pressurizer gas space. The 472 scf of hydrogen is assumed to be released
5 immediately into Containment at the initiation of the LOCA.

5 15.16.3 EVALUATION OF RECOMBINATION TO CONTROL HYDROGEN
5 CONCENTRATIONS

5 15.16.3.1 Hydrogen Flammability Limits

5 In order to determine the acceptability of any hydrogen removal system, the hydrogen concentration that
5 would constitute a potential hazard if that concentration were exceeded must be established. Regulatory
5 Guide 1.7 defines a concentration limit of 4 volume percent for hydrogen accumulation following a loss of
5 coolant accident.

5 The hydrogen generation which occurs following a design basis LOCA is a slow process driven by sump
5 radiolysis and metal corrosion. Calculations have shown that many days are required to reach the
5 regulatory limit of 4 volume percent. A hydrogen concentration slightly above 4 volume percent is
5 generally accepted as a lower flammability limit. Furthermore, assuming no credit for the Containment
5 Hydrogen Recombiner System, the concentration thirty days following a design basis LOCA is
7 approximately 6.9 volume percent. Studies of containment structural capacity and the effects of hydrogen
5 combustion have shown concentrations much higher than 4 volume percent are required to threaten the
5 integrity of a large dry containment like the Oconee containments. Concentrations in excess of 12 volume
5 percent would be required to present a challenge to the integrity of the Oconee containments.

5 Concentrations of this magnitude are only expected during core damage accidents like those studied in
5 probabilistic risk analyses.

5 Although a concentration greater than 4 volume/percent may be acceptable, the lower flammability limit
7 of 4 volume/percent specified by Regulatory Guide 1.7 is nevertheless used in this evaluation.

5 15.16.3.2 Evaluation of Recombination to Control Hydrogen Concentrations

5 Prediction of hydrogen generation following the loss-of-coolant accident using the assumptions and
5 method of analysis described in Section 15.16.2, "Post-Accident Hydrogen Generation" shows that
5 although hydrogen production rate decreases as the post-accident time increases, total hydrogen
5 accumulation can exceed the lower flammability limit of 4 volume percent. The analysis shows that using
5 conservative assumptions, post-LOCA hydrogen concentrations can reach 3 volume percent in
7 approximately 168 hours (7 days) and 4 volume percent in approximately 310 hours (13 days). A method
5 of control is therefore necessary to prevent hydrogen accumulation from exceeding the Regulatory Guide
5 1.7 limit of 4 volume percent.

5 Recombination of hydrogen and oxygen in the reactor building atmosphere is the chosen means of
5 post-accident hydrogen control. The Containment Hydrogen Recombiner System (CHRS) is designed to
5 operate at a flowrate of greater than 50 SCFM with concentrations of 0.5 volume percent and a
5 recombination efficiency of 95%. Additionally, use of the recombiner will not increase offsite releases of
5 radioactive material.

5 The basic approach evaluated herein is to allow the hydrogen concentration to increase for a minimum of
5 7 days prior to placing the CHRS into service. This allows time for pressures and temperatures to decrease
5 in the Reactor Building prior to placing the system in service. With hydrogen concentrations
5 conservatively calculated following Regulatory Guide 1.7 methodology not to reach 4 volume percent in
7 containment for 310 hours after the initiation of the event, allowing this 7 day time would not cause the 4
5 limit to be exceeded. Steps are taken to place the recombiner in service when the hydrogen concentration
5 exceeds 0.5 volume percent within the preceeding time limitations and within the pressure/temperature
5 limitations of the recombiner system components. The analysis shows that when recombiner operation is
5 begun as stated above at a flow rate of greater than 50 SCFM, safe hydrogen concentrations will be
5 maintained in containment.

5 Post accident hydrogen concentrations are indicated by the Containment Hydrogen Monitoring System
5 (CHMS). The CHMS is described in Section 9.3.7, "Containment Hydrogen Monitoring System" and is
5 shown in Figure 9-15. This instrumentation provides two redundant channels of hydrogen monitoring
5 that can monitor hydrogen concentrations at different levels of the containment including CHRS inlet and
5 return concentrations. Should both trains of hydrogen monitoring be inoperable and no other means of
5 hydrogen measurement be available, the CHRS will be placed in service after 7 days from initiation of the
5 accident to assure hydrogen concentrations are not exceeded.

5 In order to assure high concentration pockets of hydrogen do not exist and that representative samples of
5 hydrogen can be obtained, adequate mixing of hydrogen throughout containment should exist. Mixing in
5 the Reactor Building atmosphere is expected to be good. The Reactor Building cooling fans or sprays
5 will introduce considerable turbulence to the building atmosphere to provide good mixing of hydrogen in
5 the early stages of the accident. In addition, all the Reactor Building volumes are connected by large vent
5 areas (stair wells, elevator shafts, grating) to promote good air circulation.

5 Figure 15-89 shows the Reactor Building cross-section. The hydrogen generated will be primarily from
5 the corrosion of aluminum HVAC equipment in the large open area of the containment and from
5 radiolysis of water in the sump and water leaking from the RCS. These locations are within the

5 unrestricted main volume of the building and will permit the hydrogen to diffuse rapidly and provide a
5 uniform mixture in this area. This rapid mixing occurs because hydrogen has a high diffusion rate and a
5 low generation rate, and is capable of diffusing in all directions. The hydrogen will diffuse very rapidly
5 giving an even distribution under the conditions existing in the Reactor Building. This situation is not
5 analogous to one where attempts are made to mix streams of gases under dynamic conditions where
5 residence times and mixing distances are critical. In addition, the thermal mixing effects, heating of air
5 above the hot sump water, and possible steam releases from the RCS will move the hydrogen laden air
5 from the points of generation toward the cold external walls and emergency cooling equipment. Although
5 hydrogen is lighter than air, it will not tend to concentrate in high areas because of the high diffusion rate
5 and because of the open design of the Reactor Building.

5 Since the hydrogen is generated primarily from corrosion of aluminum and core radiolysis in the large
5 open areas, the hydrogen must diffuse from the major volumes into those minor volumes which are
5 enclosed. The minor volumes or those not having good communication with the major volumes would
5 be at a lower hydrogen concentration because the hydrogen is diffusing from the higher concentration
5 level to a lower concentration level. Accordingly, pockets, if they exist, will be low concentration pockets
5 rather than high concentration pockets. As the maximum concentration in the major volume will never
5 exceed the 4.0 volume/percent limit, flammable or explosive mixtures will not exist in the minor volumes
5 which might be considered as pocket areas.

5 The ability of hydrogen to diffuse rapidly into all volumes is inferred by a condensing steam
5 environment (CSE) experiment (Reference 8) which measured the spatial concentration of iodine in the
5 various compartments. The tests showed very good mixing in the main chamber and a rapid interchange
5 by diffusion and mixing with the atmosphere of other chambers which had limited communication. The
5 diffusivity of hydrogen is approximately 10 times that of iodine so a more uniform mixture would be
5 expected for hydrogen than for iodine. Also, the higher concentrations would provide greater
5 concentration gradients for better diffusion than was indicated by the CSE tests.

5 During a DBA LOCA, the operation of Reactor Building sprays and RBCUs will provide mixing in
5 containment. This along with the fact that the hydrogen generation rates are low for the majority of the
5 accident support the conclusion that a nearly uniform hydrogen concentration will exist in containment.
5 Even though the average hydrogen concentration throughout containment may be less than 4 v/0, some
5 small pockets of hydrogen exceeding 4 v/o by a small amount would not be detrimental. Results of
5 experiments summarized in Regulatory Guide 1.7 state that for hydrogen concentrations in the rage of 4
5 to 6 volume percent, partial burning of the hydrogen above 4 percent may occur. However, in this range
5 of 4 to 6 percent, the rate of flame propagation is less than the rate of rise of the flammable mixture.
5 Therefore, whether uniform mixing exists or not, hydrogen concentration at 4 volume percent or slightly
5 higher are not a concern.

5 15.16.4 CONTAINMENT HYDROGEN RECOMBINER SYSTEM DESCRIPTION

5 The Containment Hydrogen Recombiner System consists of a portable hydrogen recombiner, control
5 panel for the recombiner, and piping. The Oconee recombiners are Thermal Hydrogen Recombiners
5 developed and constructed by Rockwell International. Two recombiners are normally maintained at the
8 Oconee site. Only one recombiner is required operable per Oconee SLC 16.6.10, "Containment Hydrogen
8 Recombiner System". Duke Power Company maintains a lease agreement with Carolina Power and
5 Light (CP&L) and Florida Power and Light (FP&L) for use of the second recombiner when needed at
5 the H.B. Robinson Nuclear Site for CP&L and the Turkey Point Nuclear Site for FP&L. This
5 agreement is based on the sharing of recombiners between sites as described in Regulatory Guide 1.7.

5 The recombiner is normally not connected to a containment building. When needed post-LOCA, the
5 recombiner and control cabinet will be moved to the affected unit. The control cabinet will be installed

5 on a pad near the recombiner. The recombiner will be anchored to its foundation, and connected by
5 flexible piping to the piping which runs to and from containment penetrations 60 and 61.

7

5 The hydrogen recombiner controls hydrogen by recombining hydrogen with oxygen to form water vapor,
5 which is returned to the reactor building. The air is heated by radiant heaters to a temperature high
5 enough (approximately 1200°F) to begin recombination of the hydrogen and oxygen to form water vapor.
5 Recombination of hydrogen and oxygen is an exothermic reaction and the recombiner is designed to use
5 the heat generated by the reaction to aid in maintaining the process. As temperature increases due to heat
5 generated, controls automatically reduce heater output to maintain proper reaction chamber temperature
5 of approximately 1340°F. The recombiner is capable of processing 90 SCFM with a recombination
5 efficiency of at least 95% for hydrogen concentrations greater than 0.5 volume percent. Although the
5 design flowrate for the recombiner is 90 SCFM, the operating flow rate at Oconee is less since there are
5 several hundred feet of supply and return piping. The minimum required flow rate for post-accident
7 operation is 50 SCFM. The Hydrogen Recombiners are located in a mild environment and are therefore
7 not within the scope of 10CFR50.49. Major component data is listed in Table 15-25.

6 Any condensation that may accumulate in the CHRS supply and return piping will be routed by a gravity
7 drainage system to the Reactor Building Normal Sump.

5 The recombiner is the preferred method of hydrogen control since there is no release of radioactive
5 material to the atmosphere. The air/hydrogen mixture is drawn from the reactor building and the air and
5 water vapor mixture is returned to the Reactor Building.

5 The supply flow path for recombiner operation is from the Reactor Building via Inboard Containment
5 Isolation Valve 1(2)(3)PR-7, Penetration 60, Outboard Containment Isolation Valve 1(2)(3)PR-8, and
7 flexible coupling PR FX0001 & 0002 to the recombiner unit. The flow path through the recombiner is
5 the blower, the flow element, the radiant heaters, the reaction chamber, and the air blast heat exchanger.

5 The air blast heat exchanger is cooled by the air blast blower, which forces approximately 3000 CFM of
5 air at ambient temperature through the heat exchanger to cool the air/water vapor mixture to near
5 ambient temperature before returning to the Reactor Building. The recombiner will automatically
5 shutdown if outlet temperature reaches 146°F.

7 The return flow path is via flexible coupling PR FX0005 and PR FX0006, manual valve 1(2)(3)PR-61,
5 Outboard Containment Isolation Valve 1(2)(3)PR-10, Penetration 61, and Inboard Containment Isolation
5 Valve 1(2)(3)PR-9.

5 Electric motor operated valves 1(2)(3)PR-7 and 1(2)(3)PR-9 close on an Engineered Safeguards Channel 1
5 signal. Air operated valves 1(2)(3)PR-8 and 1(2)(3)PR-10 close on an Engineered Safeguards Channel 2
5 signal. These are redundant channels which actuate on low RC pressure or high RB pressure to close
5 these containment penetration isolation valves.

5 An alternate supply flow path is provided by Hydrogen Recombiner Inlet Containment Isolation Valve
5 1(2)(3)PR-59 and an alternate return flow path is provided by Hydrogen Recombiner Return
5 Containment Isolation Valve 1(2)(3)PR-60. These valves are normally closed EOVs, capable of being
5 operated electrically from the cable rooms. The valves are installed to ensure a failure of 1(2)(3)PR-7 or
5 1(2)(3)PR-9 would not prevent operation of the CHRS. Power is supplied to these valve from non-safety
5 related, non-load shed power. The flow configuration of the CHRS is shown on Figure 15-110.

5 Manual action is relied upon outside of containment to restore failed valves or other components that
5 may fail to operate post-LOCA. Sufficient time is available to correct any problems that may occur.

7

5 All piping and equipment necessary for the function of the CHRS are designed to withstand a Safe
6 Shutdown Earthquake without a loss of function except CHRS power. Power for the Containment
6 Hydrogen Recombiner is normally supplied from non-safety power via the Auxiliary Power Upgrade
6 Busses. In the event power is not available from the normal supply, power can be manually restored
6 from either of two non-safety, non-loadshed power supplies.

6

5 Detailed design information is provided in Reference 13.

5 15.16.5 CONTAINMENT HYDROGEN RECOMBINER SYSTEM OPERATION
5 AND TESTING

5 Following a LOCA, the process of placing the CHRS in service is begun when the containment hydrogen
5 concentration in containment reaches 0.5% by volume. The recombiner and control cabinet are placed
5 on the appropriate pads of the affected Unit. Electrical and mechanical connections are made to connect
6 the recombiner to the affected Unit. Mechanical connections are leak rate tested and valve alignments are
6 made to align the CHRS for operation. After 7 days, when system operating parameters are within
5 allowable limits, the recombiner is placed in service.

8 Testing of the recombiner and flow path is performed every 18 months. This testing includes:

5 • Visual inspection of the CHR Unit

5 • Calibration of all recombiner instrumentation and control circuits

5 • Operation of the CHRS in the post-LOCA configuration

5 • Verifying proper operation of heaters and controls

5 • Verifying acceptable flowrates through the recombiner

6 • Verifying acceptable flowrates through the hydrogen recombiner flowpath

5 • Leak rate testing of the recombiner and piping

5 • Leak rate testing of the blind isolation flanges on the CHRS permanent piping (tested after each
5 installation)

7

5 15.16.6 CONCLUSIONS

7

5 The analyses also show that the hydrogen generated in the Reactor Building following a LOCA can be
7 adequately controlled using the CHRS with a flowrate of greater than 50 SCFM (Figure 15-87). The
7 peak hydrogen concentration of 3.97 v/o does not occur until 30 days post-LOCA.

5 ## 15.16.7 REFERENCES

1 1. Shure, K., Fission Product Decay Energy, *WAPD-BT-24*, December 1961.

1 2. Allen, A. O., *The Radiation Chemistry of Water and Aqueous Solutions*, D von Nostrand Co., Inc.,
1 1961.

1 3. Morrison, D. L., An Evaluation of the Applicability of Existing Data to the Analytical Description of
1 a Nuclear-Reactor Accident, Quarterly Progress Report for April through June, 1968, *BMI-1844*, July
1 1968.

1 4. Zittel, H. E., Radiolysis Studies, ORNL Nuclear Safety Research and Development Program
1 Bi-monthly Report for September-October 1967, *ORNL-TM-2057*, Nov. 27, 1967.

1 5. Coward, H. F., Jones, G. W., Limits of Flammability of Gases and Vapors, *Bureau of Mines Bulletin*
1 *503*.

1 6. Markstein, G., "Instability Phenomena in Combustion Waves", 4th Symposium on Combustion.

1 7. Shapiro, A. M., Mofette, T. R., Hydrogen Flammability Data and Application to PWR
1 Loss-of-Coolant Accident, *WAPD-SC-545*, September 1957.

1 8. Coleman, L. F., et al, Large-Scale Fission Product Transport Experiments, *BNWL 926*, pp. 2.1 to
1 2.21, Dec. 1968.

1 9. Stinchcombe, R. A., Goldsmith, P., "Removal of Iodine from Atmosphere by Condensing Steam",
1 *Journal of Nuclear Energy Parts A/B 20*, pp. 261 to 275, 1966.

1 10. Stinchcombe, R. A., Goldsmith, P., Clean-up of Submicron Particles by Condensing Steam,
1 *AERE-M-1213*.

1 11. Goldsmith, P., May, F. G., "Diffusiophoresis and Thormophoresis in Water Vapor Systems", *Aerosol*
1 *Science*, C. N. Davies, Ed., Academic Press, Inc., New York, New York, pp. 163-194 (1966).

1 12. Hyland, E. L., "Design Criteria, Containment Hydrogen Recombiner System (Rev. 0)," Duke Power
1 Company, June 24, 1983.

1 13. H. B. Tucker (Duke) letter to H. R. Denton (NRC) dated October 20, 1986.

5 14. Regulatory Guide 1.7 (Rev 2), "Control of Combustible Gas Concentrations in Containment
5 Following a Loss-of-Coolant Accident"

5 15. OSC - 6191 (Rev. 0), "Reanalysis of Oconee Hydrogen Recombiner and Purge System Requirements"

5 16. Wiens, L. A. (NRC) letter to J. W. Hampton (Duke) dated February 7, 1996.

5 17. OSC - 123 (Rev. 1), "Activity on Filter RB Hydrogen Purge"

5 18. OSC - 6534 (Rev. 0), "Hydrogen Purge Cart Operator Dose Rate"

5 19. OSC - 3781 (Rev. 5), "Documentation of Maximum Hypothetical Accident(MHA) Dose Model For
5 Oconee Nuclear Station"

5 20. OSC - 6064 (Rev. 1), "Estimated Radiation Dose Rates in the Auxiliary Building Following a Large
5 Break LOCA"

8 21. Request for Facility Operating License Amendment Rod Internal Pressure in Spent Fuel Pool
8 Criteria, from W. R. McCollum, Jr. (Duke Energy) to USNRC, September 30, 1998, Oconee Nuclear
8 Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

8 22. Letter from David E. Labarge (USNRC) to W. R. McCollum, Jr. (Duke Energy), "Issuance of
8 Amendments - Oconee Nuclear Station, Units 1, 2, and 3 (TAC Nos. MA3706, MA3707, and
8 MA3708)", March 26, 1999.

8 23. BAW-10141P-A Rev. 1, TACO2 - Fuel Performance Analysis, Babcock & Wilcox Fuel Company,
8 June 1983.

8 24. BAW-10162P-A, TACO3 Fuel Pin Thermal Analysis Computer Code, Babcock & Wilcox Fuel
8 Company, November 1989.

1 **THIS IS THE LAST PAGE OF THE CHAPTER 15 TEXT PORTION.**

Table 15-17. Post-Accident Hydrogen Control Sources of Radiation

5

Location	Source
Core	100% fission products
	Transuranium activation products (Np-239, U-239)
	Activated clad and structural materials
5	
5	
Reactor Building atmosphere	100% of noble gases
Emergency core cooling water	50% halogens 1% solids
	99% solid fission products 50% halogens
	Transuranium activation products (Np-239, U-239)
	Activated clad and structural materials

Table 15-18. Post-Accident Hydrogen Control. Assumptions For Calculation of Absorbed Energy

1. The core has operated at 2568 MWt for an average irradiation period of 620 days.
2. The core flooding tanks and borated water storage tanks have been discharged and coolant is circulating through the core and spray system from the sump.

5 3. 100 percent of the gases, 50 percent of the halogens and 1 percent of the solids are released
5 instantaneously from the core at the time of the accident.

5 4. The halogens are removed instantaneously from the reactor building atmosphere to the emergency
5 cooling water.

5 5. The volume of fluid in each region remains constant.

5 6. The daughters descending from radioactive materials in a region remain in the same region with their
5 parents, except for the gaseous daughters of the iodine in the cooling water. These were allowed to
5 escape to the reactor building atmosphere.

Table 15-25. Containment Hydrogen Recombiner Data

Type	Thermal
Design Pressure	60 psig
Design Temperature	300 °F Influent and Effluent
Maximum Operating Pressure	23 psig
Maximum Operating Temperature	230 °F Influent
	170 °F Effluent
Basic Material	Stainless Steel
Electrical Requirements (Standby)	120 V, 1 phase, 60 Hz, 600 W
Electrical Requirements (Operating)	480 V, 3 phase, 60 Hz, 75 kW
Recombiner Efficiency	95% Minimum of Influent Hydrogen Concentrations Greater than 1/2 Volume %
Process Gas	0-4 Volume % Hydrogen, Water, Saturated Air Mixture
Design Flow Rate	90 scfm
System Pressure Drop	1.0 psid with Influent Gas at 14.7 psia, 120 °F
Weight	10,500 lbm

5 FOR INFORMATION ONLY Figure 15-81.

5 Deleted Per 1995 Update

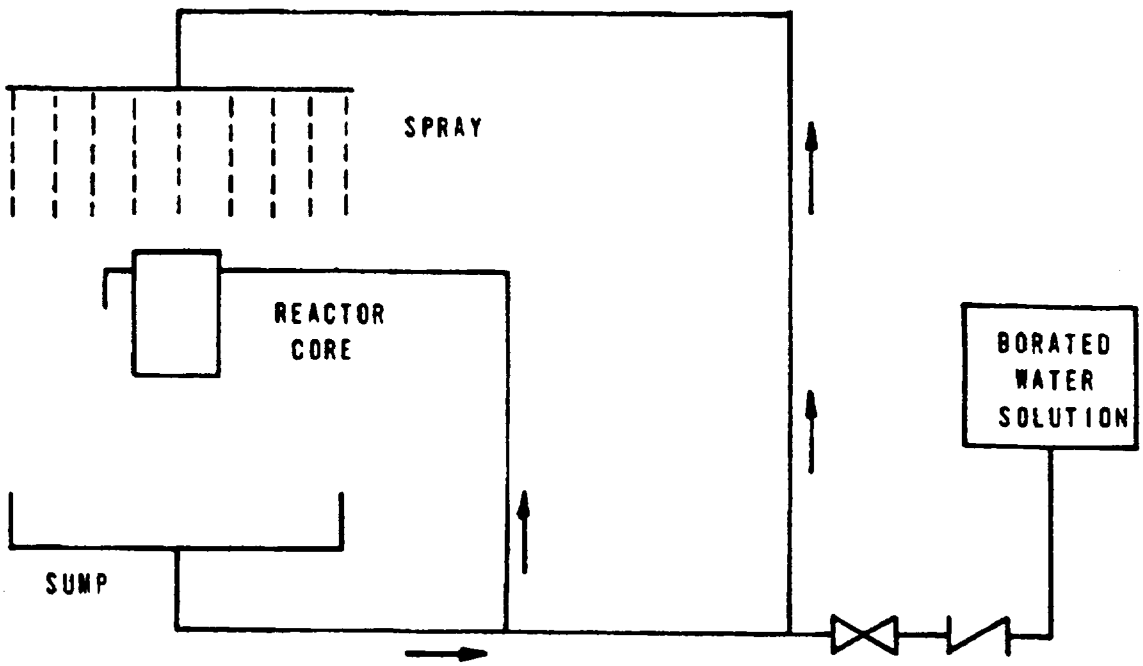
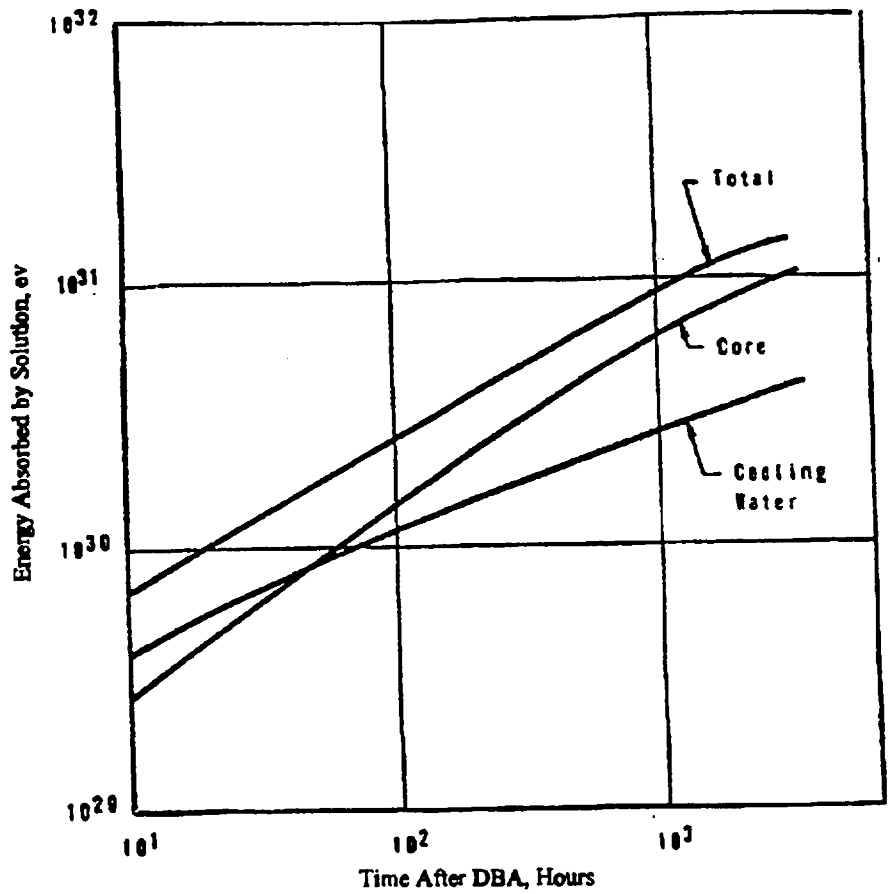


Figure 15-82.
Post-Accident Hydrogen Control - Reactor Building Spray System

5 Figure 15-83.

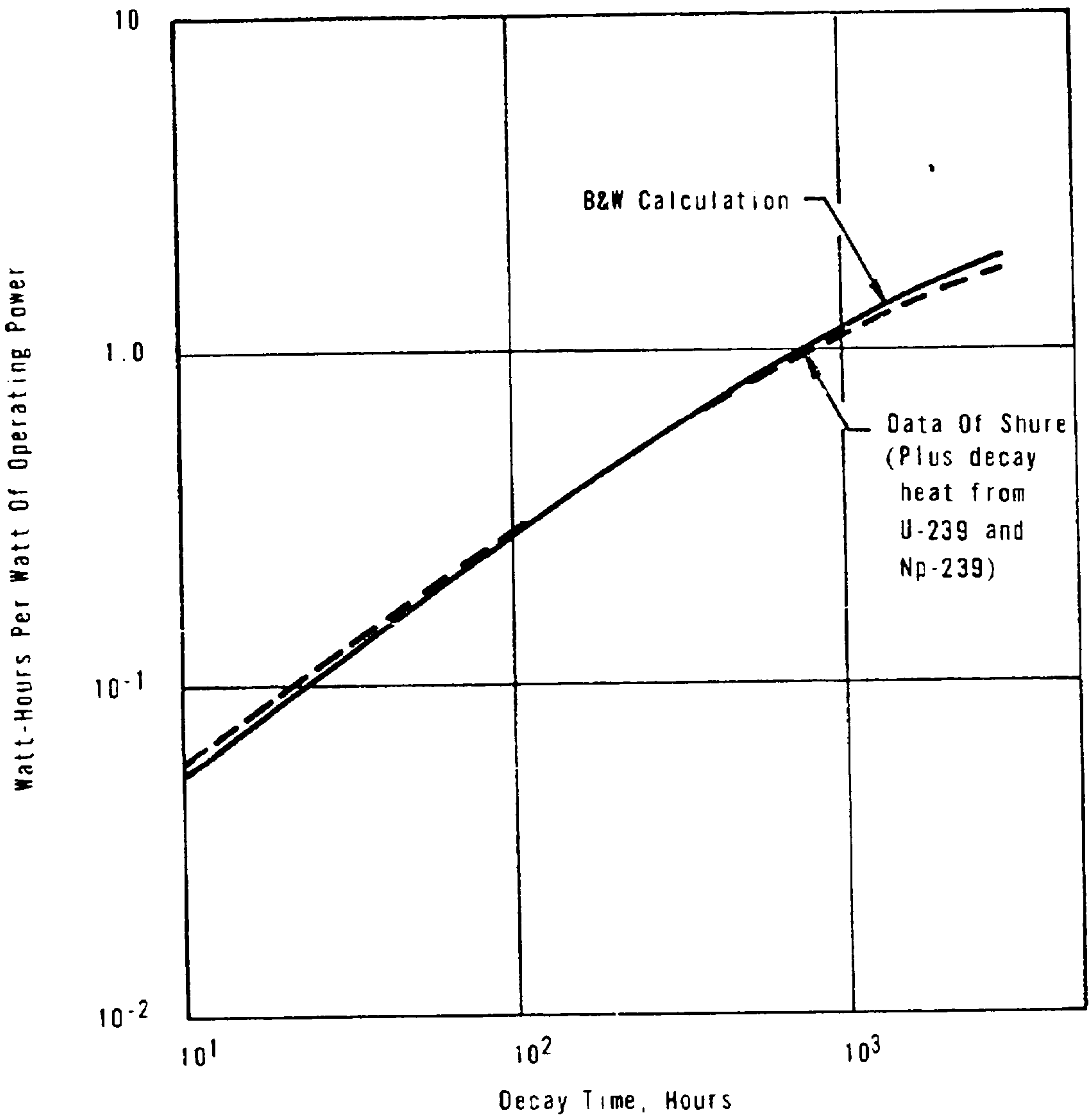
5 Deleted Per 1995 Update

FOR INFORMATION ONLY



5 Figure 15-84.

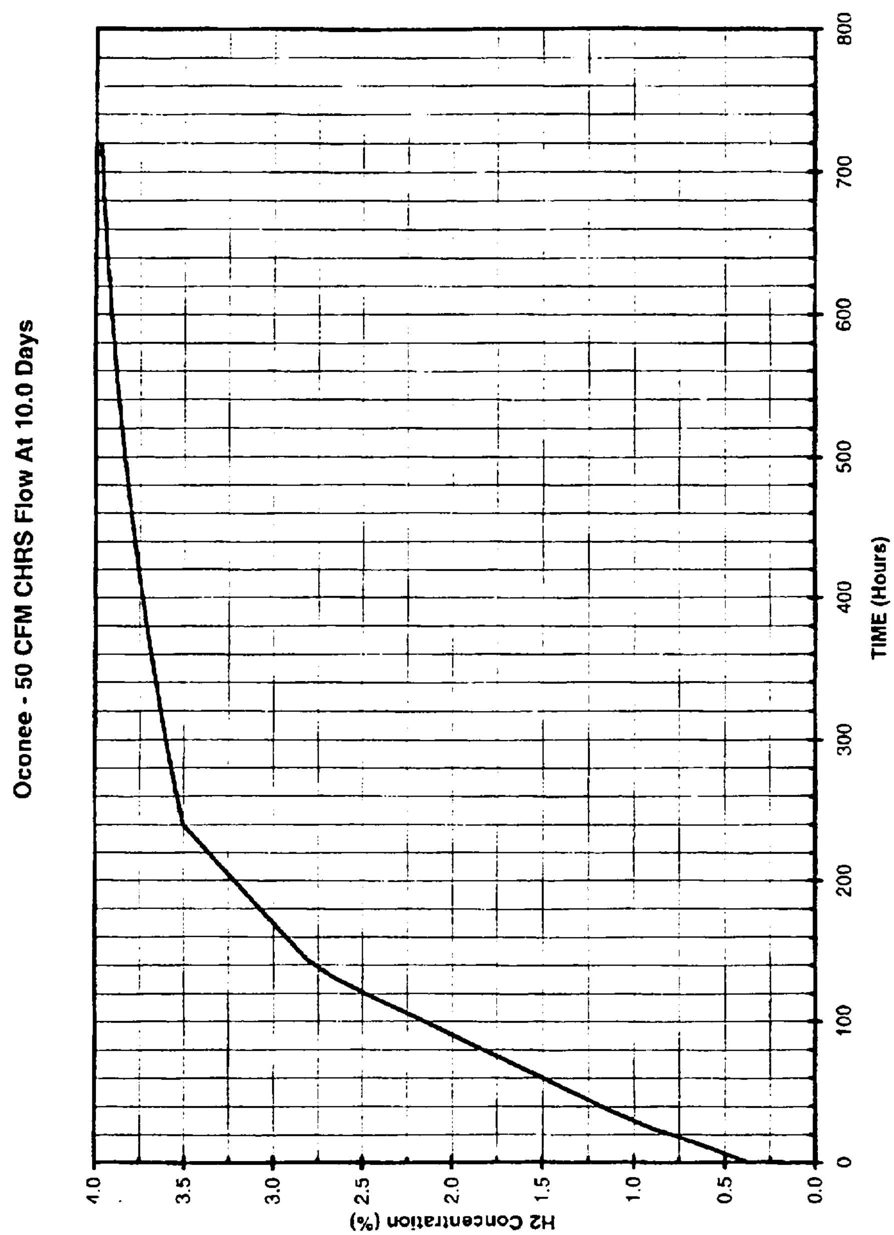
5 Post-Accident Hydrogen Control - Energy Absorbed by Solution Following DBA



1 Figure 15-85.
1 Post-Accident Hydrogen Control - Integrated Gamma Decay Heat

7 Figure 15-86.
7 Deleted Per 1997 Update

FOR INFORMATION ONLY



7 Figure 15-87.
7 Post-Accident Hydrogen Control - Post-LOCA Hydrogen Concentration Using CHRS

5 Figure 15-88.
5 Deleted per 1995 Update

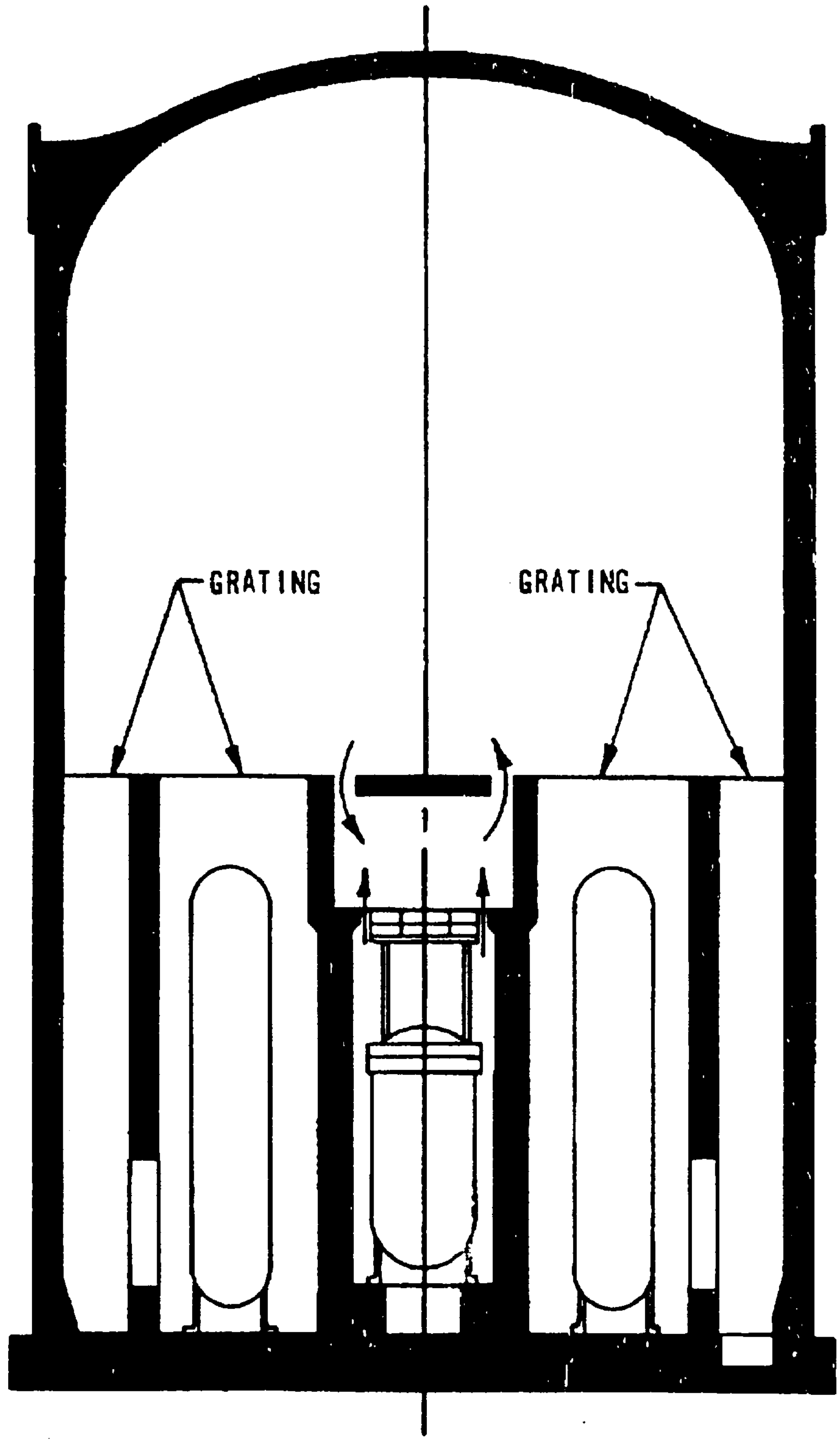
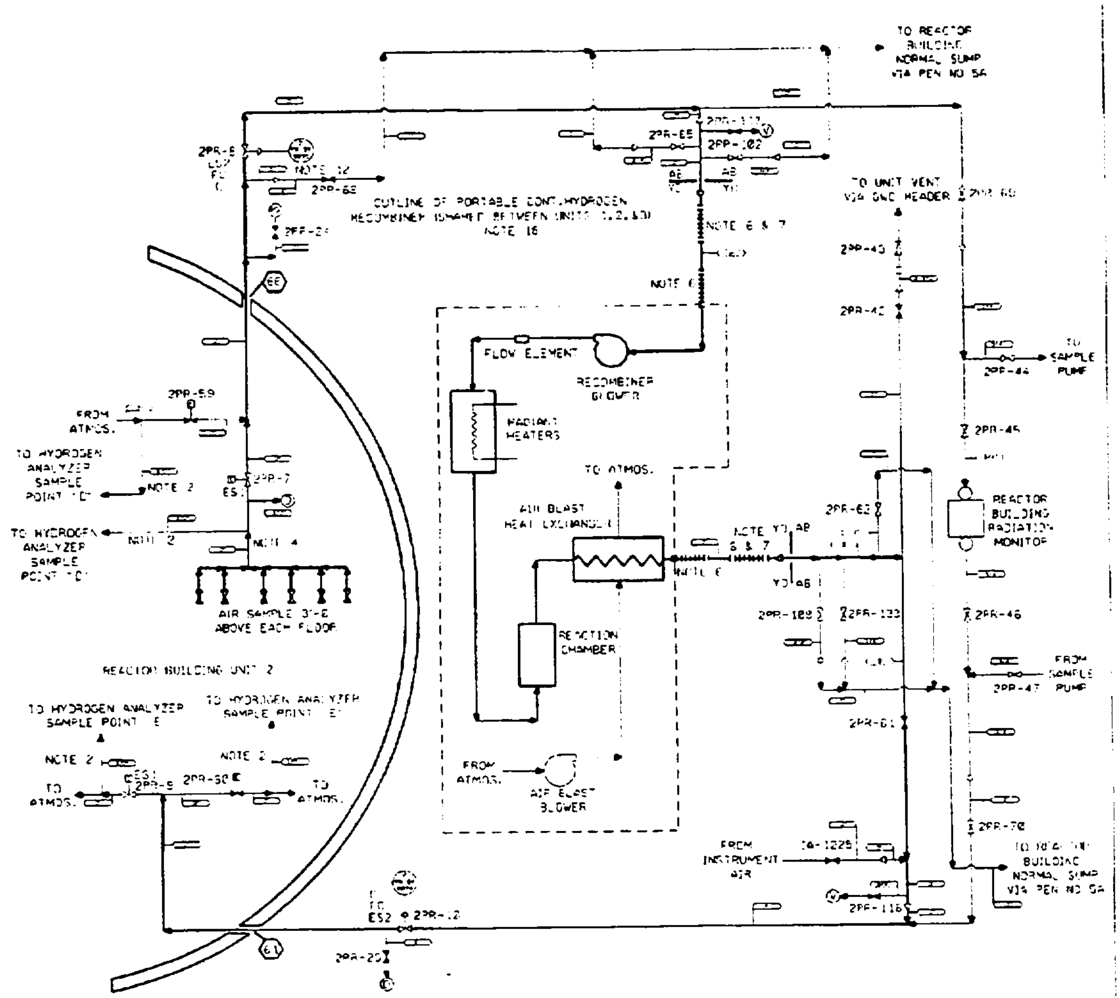


Figure 15-89.
Post-Accident Hydrogen Control - Reactor Building Arrangement



NOTES:

1. HYDROGEN RECOMBINER MODE REPRESENTED BY BOLD LINES.
2. REDUNDANT (SAFETY-RELATED) INSTRUMENT TAPS TO BE SEPARATED 10 INCHES MINIMUM.
4. CLASS BREAK 'B' UPSTREAM OF BRANCH.
5. THIS DRAWING IS BASED ON [illegible].
6. PORTABLE FLEXIBLE METAL PIPING USED TO CONNECT RECOMBINER.
7. BLIND FLANGE TO BE LOCKED INSIDE OF A BOX OR NUTS TO BE TACK WELDED TO PREVENT INADVERTANT UNMONITORED GASEOUS EFFLUENT RELEASE.
12. VALVE INSTALLED IN REVERSE FLOW DIRECTION PER OSS-0254.00-36-4001.

7
7

Figure 15-110.
Containment Hydrogen Recombiner System

ENCLOSURE 2

ATTACHMENT D

No Significant Hazards Evaluation

The Commission has provided standards for determining whether a significant hazards consideration exists as stated in 10CFR50.92. A proposed amendment to an operating license for a facility involves no significant hazards consideration if operation of the facility in accordance with a proposed amendment would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. A discussion of these standards as they relate to this change request follows.

1. **Will operation of the facility in accordance with this proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?**

Response: No

The Oconee Nuclear Station, Units 1, 2, and 3 (ONS), containment Post-Accident Hydrogen Control System is currently classified as a safety system. The containment Post-Accident Hydrogen Control System is composed of the Containment Hydrogen Monitoring System and the Containment Hydrogen Recombiner System. Hydrogen control components (monitors and recombiners) are not considered to be accident initiators. Therefore, this change does not increase the probability of an accident previously evaluated.

The containment Post-Accident Hydrogen Control System is provided to ensure the hydrogen concentration is maintained below the limit of 4.0% so that containment integrity is not challenged following a design basis Loss of Coolant Accident (LOCA). Existing analysis show that the hydrogen concentration will not reach the limit of 4.0% for at least 15 days after a design basis LOCA. Containment failure due to hydrogen combustion without the hydrogen recombiners is unlikely based on the results of the Oconee Individual Plant Examination study. The detailed ONS specific containment integrity analysis indicates that the ultimate pressure capacity of the ONS containment building is approximately 140 psig, mean value (Oconee IPE, Section G). Therefore, this change does not increase the consequences of accidents previously evaluated.

Removal of the existing requirements for hydrogen control will eliminate the Emergency Operating Procedure (EOP) steps for hydrogen monitoring and hence simplify the EOPs. This would have a positive impact on public health risk by reducing the probability of operator error during potential accidents and hence reduce the core damage frequency. Removal of the existing requirements for hydrogen recombiners will also decrease the potential for additional leakage from containment following severe accidents. The changes described in this request result in a small risk reduction.

Therefore, this change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

2. Will operation of the facility in accordance with this proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

This proposed change does not change the design or configuration of the plant beyond the containment Post-Accident Hydrogen Control System. Hydrogen generation following a design basis LOCA has been evaluated in accordance with regulatory requirements. Deletion of the containment Post-Accident Hydrogen Control System from the Technical Specifications does not alter the hydrogen generation processes post-LOCA. The consideration of hydrogen generation will no longer be included in the ONS design basis. Therefore, this change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Will operation of the facility in accordance with this proposed change involve a significant reduction in a margin of safety?

Response: No

The changes described in this change request result in a risk positive change. Removal of the existing requirement for a containment Post-Accident Hydrogen Control System will, by eliminating the EOP steps for hydrogen monitoring, result in lower operator error probabilities. Removal of the existing requirement for the portable hydrogen recombiner will decrease the potential for leakage of the containment atmosphere following severe accidents. Therefore, this change involves an increase in safety, not a reduction in a margin of safety.

Based on the negative responses to these three criteria, Duke has concluded that the proposed change involves no significant hazards consideration.

ENCLOSURE 2

ATTACHMENT E

Environmental Impact Analysis

Duke has determined the proposed Technical Specification change does not result in any increase in the amount or type of effluent that may be released offsite, and results in no increase in individual or cumulative occupational radiation exposure. The proposed Technical Specification amendment involves no significant hazards consideration and, as such, meets the eligibility criteria for categorical exclusion set forth in 10CFR51.22(c)(9).