Florida Power
CORPORATION

January 30, 1981

File: 3-0-30

Mr. Darrell G. Eisenhut
Director
Division of Licensing
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Crystal River Unit 3
Docket No. 50-302
Operating License No. DPR-72
NUREG-0737, Post-TMI Requirements

Reference: Florida Power Corporation (FPC) Letter,
Baynard to Eisenhut; December 15, 1980

Dear Mr. Eisenhut:

The referenced Florida Power Corporation (FPC) letter provided proposed implementation and licensing submittal schedules as requested by your letter of October 31, 1980. By this letter FPC provides those items of the referenced FPC letter which indicated a January 31, 1981, schedule for submittal.

Item I.A.1.1 Shift Technical Advisor

In compliance with the short-term requirements of NUREG-0578 and the subsequent clarification dated October 30, 1979, FPC is presently utilizing a group of interim STAs. The qualifications, training, duties and shift rotation of the interim STAs have been accepted by the NRC Staff (see your May 5, 1980, "Evaluation of NUREG-0578 Category A Implementation"; Reid to Hancock).

As was delineated in our letter of December 31, 1980, (Baynard to Eisenhut), FPC has developed and is presently implementing a program for permanent STA training based upon the document included in NUREG-0737 (INPO Guidelines, Rev. 0, April 18, 1980). This training program is being conducted utilizing the University of Florida, Nuclear Engineering Department; NUS; B&W and FPC. The permanent STAs are expected to replace the present group of interim STAs by December 31, 1981.

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As committed by FPC (FPC letter; Baynard to Eisenhut; dated December 31, 1980) to address the requirements of this item, FPC has enclosed five (5) copies of its "Nuclear Operations Technical Advisor Training Program" for your review. FPC is meeting the recommendations of the INPO guidelines and in some cases have exceeded these (for example, in the area of STA qualifications). The STAs will be requalified vis-a-vis the present SRO requalification program.

FPC has considered three alternatives for the long-term STA utilization or phase-out. The following are offered to aid future guidance in this area and should not be interpreted as a commitment:

- Continue the STA program indefinitely for the life of the plant.
- To satisfy the long-term requirement, require a Bachelors Degree for the Shift Supervisor, phase-out the STAs, and utilize in this position.
- Phase-out the STAs, and utilize these personnel in a supervisory position on the operating staff (this does not include the Shift Supervisor position).

Item I.C.1 - Short-Term Accident and Procedures Review

The Abnormal Transient Operating Guidelines (ATOG) Program of the Babcock & Wilcox Owners Group was discussed with the NRC Staff on December 16, 1980. The draft ANO-1 operator guidelines which had been provided to the Staff are representative of the guidelines which are in preparation for Crystal River Unit 3. In order to facilitate confirmation by the Staff that all plant specific guidelines are essentially identical, FPC will provide the draft Crystal River Unit 3 guidelines when available.

Item II.B.1 - Reactor Coolant System Vents

As committed in our December 15, 1980, letter (Baynard to Eisenhut), five (5) copies of our position report on venting the reactor vessel head are herein provided for your review. This report concludes the reactor vessel head vent is not necessary for removal of noncondensible gases in order to establish and maintain natural circulation for long-term core cooling following a small break LOCA. Specifically, should significant quantities of noncondensible gases collect in the reactor vessel head region, natural circulation is still assured as this gas does not inhibit loop flow. The gas which does flow into the hot legs, either during generation of the gas or subsequent cooldown and expansion of the reactor vessel head gas, will be removed by the hot leg vents. Therefore, as shown in our report, a reactor vessel head vent is not needed to assure natural circulation and core cooling.

Item II.K.3.2 - Report on PORV Failures

The attached generic report ("Report on Power - Operated Relief Valve Opening Probability and Justification for Present System and Setpoints", Babcock and Wilcox Document No. 12-1122779 - Rev. 1) was prepared at the request of FPC and other operating plants with Babcock and Wilcox designed reactors to address this Action Plan item. Based on the analysis provided therein, and with the existing reactor high pressure trip and PORV pressure setpoints, an automatic block valve closure system is not necessary. Five (5) copies of this report have been enclosed with this letter for your review.

Item II.K.3.7 - Evaluation of PORV Opening Probability

The report referenced in Item II.K.3.2 above, also addresses this Action Plan item and supports the contention that an automatic block valve closure system (described in Action Plan item II.K.3.1) is not necessary to reduce the probability of a small-break LOCA from a stuck open PORV with the existing reactor high pressure trip and PORV pressure setpoints.

Item II.K.2.13 - Thermal-Mechanical Report

As requested in your October 31, 1980 letter, and as committed in our December 31, 1980 letter, five (5) copies of a generic thermal-mechanical report are enclosed for your review. This report, BAW-1648; "Thermal-Mechanical Report - Effect of HPI on Vessel Integrity for Small Break LOCA Event with Extended Loss of Feedwater", discusses the generic evaluation of the reactor vessel brittle fracture concern during recovery from a small break LOCA with extended loss of all feedwater. Based upon our evaluation of the conservatisms assumed and the completed and ongoing efforts to significantly increase the reliability of the emergency feedwater system, FPC contends that Crystal River Unit 3 is safe for continued operation. Worthy of note in our evaluation are the facts that the Crystal River Unit 3 reactor vessel will not accummulate a radiation exposure equivalent to 3.8 Effective Full Power Years (EFPY) until at least mid-1983, and the BWST water temperature has historically been maintained above 60°F. The assumptions made in the attached report are very conservative for Crystal River Unit 3.

Item II.K.3.30 - Small Break LOCA Methods to Show Compliance with Appendix K to 10 CFR 50

FPC is evaluating the development of a generic program to address the small-break LOCA model concerns identified in the applicable B&O Task Force reports. To fully evaluate these concerns and incorporate the discussions with your staff in a meeting held on December 16, 1980, we will require until March 1, 1981, to evaluate the forthcoming B&W proposal to perform the model modifications and to determine FPC's course of action. You will be advised by March 1, 1981, of our decision on

this issue. FPC states the existing small-break LOCA model, as approved by the NRC staff, meets the rquirements of 10 CFR 50, Appendix K.

Item III.D.3.4 - Control Room Habitability Requirements

A comprehensive habitability re-evaluation of the Crystal River Unit 3 control room has been performed. The results of this evaluation and proposed modifications are discussed in our report entitled, "Crystal River Unit 3 Control Room Habitability Requirements." Five (5) copies of this report are hereby provided for your review.

Very truly yours,

FLORIDA POWER CORPORATION

Patsy Y. Baynard
Manager
Nuclear Support Services

Enclosures

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Position Paper
on
Reactor Vessel Head Vents

POSITION PAPER ON REACTOR VESSEL HEAD VENTS

1. Introduction

The NRC has required the installation of vents in the high points of the reactor coolant system, i.e., the hot legs, the pressurizer, and the RV head for the purpose of removing noncondensible gases which may collect in the system in order to enhance satisfactory long-term cooling[1,2]. This paper presents an assessment of the uses of the vents for achieving long-term cooling and demonstrates that the RV head vents are not necessary.

Section 2 of this report provides a summary of this paper. Section 3 provides a description of the expected course of events for a small break LOCA. Included in Section 3 is a description of the types of scenarios necessary to lead to core uncovery and the subsequent generation of noncondensible gases. Section 4 of the report provides a discussion of the ability of the hot leg vents to remove noncondensibles for a variety of plant conditions.

2. Summary and Conclusions

During a small break transient, depressurization of the primary system can cause gases to accumulate in the RV head and in the upper regions of the hot legs. With proper operator action and functional ECCS equipment, only small quantities of noncondensible gases would be generated and the voided portions of the RCS would be filled with mostly steam. In order to generate large quantities of noncondensible gases, substantial core uncovery must occur. The potential scenarios necessary to lead to core uncovery require operator errors and/or multiple failures of systems. In light of the upgrades in operating procedures and equipment following the TMI-2 accident, small break transients leading to the generation of large quantities of noncondensible gases are not expected to occur.

The ability to remove gases, including large quantities of noncondensibles, from the primary system following a small break LOCA has been assessed. By starting the RC pumps and/or by opening the hot leg vents, gases which may collect in the upper regions of the hot legs can be removed and forced or natural circulation can be established. There is no need to vent gases which are trapped within the RV head as they will not prohibit the establishment of natural or forced circulation. Subsequent plant depressurization to cold shutdown conditions can be performed, even with a gas bubble in the RV head, without interrupting natural circulation. Thus, RV head vents are not necessary to maintain natural circulation, and therefore to remove best from the core (i.e., maintain core cooling).

3. Small Break LOCA Response

The response of the primary system to a small break differs greatly depending on the break size, its location in the system, operation of the reactor coolant pumps, the number of ECCS trains functioning, and the availability of secondary side cooling. This section will provide a general discussion of the expected course of a small break LOCA, i.e., a "normal" small break. Additionally, types of scenarios necessary for a transient to progress to core uncovery and substantial noncondensible gas generation, i.e., inadequate core cooling situation, are also discussed.

3.1 "Normal" Small Break

System response to a small break can generally be characterized as follows:

a. Breaks small enough to be mitigated by the makeup system: for these breaks, if emergency feedwater (EFW) remains available, the primary system loops will remain full of coolant and the operator can initiate a normal plant cooldown.

b. Breaks which result in automatic initiation of the HPI pumps and are within the capability of the high pressure injection system without resulting in an interruption of primary system flow: the primary system pressure will be balanced at a value where the coolant outflow through the leak equals the feed rate of the high pressure injection system. By using the HPI to maintain inventory and subcooling margin, the primary system loop will remain full of coolant and the operator can initiate a normal cooldown.

c. Breaks which result in automatic initiation of HPI and also results in primary system voiding: breaks in this category are those which are not large enough to remove the energy added to the primary system fluid by the core decay heat. Steam generator heat removal is required. For smaller size breaks within this category, void formation in the hot leg could result in an interruption of natural circulation and a system pressure increase would occur. This repressurization would be terminated when the primary side liquid level falls below the elevation of the EFW injection nozzles at which time steam in the primary system would be condensed.

   For larger sized breaks within this category, the transition between the loss of natural circulation and the establishment of condensation heat removal would be a smooth process and primary system repressurization would not occur.

Analyses of small break LOCA transient response have been performed and are reported in references 3, 4, 5 & 6. As shown by these analyses, cladding temperatures will be maintained below 1100 F and no cladding ruptures nor significant metal water reaction will take place unless multiple equipment failures occur. Under these situations, large quantities of noncondensible gases are not expected to be produced.

3.2 Inadequate Core Cooling

Inadequate core cooling has been defined as situations which lead to core uncovery and excessive cladding temperatures. To aid the operator in minimizing the consequences of such an event, inadequate core cooling guidelines have been developed.[7,8,9]. As described previously, the small break analyses which have been performed do not predict large core uncovery nor excessives cladding temperatures. The types of scenarios which potentially could lead to inadequate core cooling situations are described below.

Small break LOCA mitigation relies upon the availability of the ECCS equipment. Lack of HPI due to operator intervention is a potential scenario which could lead to inadequate core cooling. This is not expected to occur due to the upgrade in emergency procedures for handling small break LOCA's.

Total failure of the ECCS can also lead to inadequate core cooling. In light of the fact that the ECCS is a safety-grade system and is redundant, operable with both on and offsite power, seismically and environmentally qualified, total failure is not expected. Additionally, the inadequate core cooling guidelines provide backup means for handling the consequences of multiple failures in order to further minimize the potential for the generation of large amounts of noncondensible gases.

Mutiple equipment failures can also result in core uncovery. For example, a total and extended loss of feedwater, main and emergency, and a single failure in the HPI system may lead to core uncovery for certain break sizes and locations. Since the HPI is a separate system from the feedwater systems, this combination of multiple failures would not be expected to occur simultaneously. Additionally, efforts are underway to upgrade the EFW systems to increase this reliability.

Failure of the operator to promptly trip the reactor coolant pumps during a LOCA could also lead to an inadequate core cooling situation. As shown in reference 10, loss of the reactor coolant pumps during a small break LOCA at a time where the primary system has reached a high void fraction could result in core uncovery and excessive cladding temperatures. However, as shown in reference 10, the peak cladding temperatures would not violate the criteria of 10CFR50.46, and substantial quantities of noncondensible gases are not expected to be generated if realistic assumptions are used. Additionally, operator training has been conducted and procedural modifications have been made to require prompt tripping of the RC pumps for a small break LOCA, thereby minimizing the potential for this sequence of events.

As described above, there are scenarios which could lead to an inadequate core cooling situation. the above discussion was not developed to be a complete set, but rather to provide a general description of

the possible scenarios. Based on the analyses which have been performed and the discussions above, it is readily apparent that operators errors and/or multiple equipment failures are required before an inadequate core cooling situation could occur. Several actions have been taken to minimize the potential for the occurrence of an inadequate core cooling situation. These include:

a. The designing of a reliable ECCS system such that small break LOCA's would be mitigated without excessive cladding temperatures occurring.

b. Upgrading of the small break LOCA procedures and additional operator training.

c. Incorporation of inadequate core cooling guidelines into the small break operating procedures, thereby minimizing the consequences of core uncovery should it occur.

d. Upgrading of the EFW system to provide additional assurance that steam generator heat removal will be available when required.

In light of these actions, if a small break LOCA should occur, the transient is not expected to result in core damage or generation of large amounts of noncondensible gases.

4. Assessment of Vent Usages

Depressurization of the primary system during a small break transient can cause gases to accumulate within the RV head and in the upper regions of the hot legs. During a "normal" small break, only small quantities of noncondensible gases would be generated. This section will discuss ways in which the hot leg vents may be utilized in order to remove gases from the primary system to allow the reestablishment of natural circulation in the event natural circulation is lost. Additionally, possible methods to depressurize the plant with a gas bubble trapped within the RV head are described.

4.1 Vent Usages for "Normal" Small Break

The need to vent gases from the primary system during a "normal" small break is limited to the class of breaks wherein energy removal via the break itself is insufficient to allow plant depressurization and which also leads to void formation in the primary system. These breaks are the Category C breaks defined in Section 3.1. The subsequent paragraphs describe how gases can be removed from the primary system for various combinations of equipment availability and demonstrate the RV head vents are not necessary.

4.1.1 RC Pumps, EFW and HPI Available

The plant response for Category C breaks with EFW available can generally be characterized as follows. The initial system depressurization will result in a reactor trip and low pressure ESFAS initiation. Operator action would then be taken to trip the operating RC pumps. The continued system depressurization will ultimately result in saturated fluid conditions in the RCS while the upper regions of the hot legs and the reactor vessel will void. Natural

circulation will be lost if the void in the hot leg becomes sufficient to fill the 180° U-bend. With the loss of circulation through the loops, the steam generator energy removal will be lost and a primary system repressurization would commence. Once sufficient primary system inventory is lost to cause the primary side liquid level to decrease below the elevation of the EFW injection nozzles, condensation of steam in the primary system would occur thereby initiating "boiler-condensor" circulation. As a consequence, the primary system pressure will decrease and the HPI flow will increase to establish a stable core cooling mode. Later in the transient, a system refill will commence. However, a gas bubble will remain trapped in the upper regions of the hot leg and in the RV head. Once the level in the primary system rises above the EFW injection nozzle elevation, heat removal via the steam generators will once again be lost and the primary system pressure would start to increase. By operating the RC pumps consistent with the small break guidelines, i.e., by "bumping" or starting the RC pump, voids in the upper regions of the hot leg will be swept out and forced circulation will be established. It is important to note that any voids present in the RV head at this time would not prohibit the reestablishment of circulation within the primary system.

With forced circulation established in the primary system, the operator can then turn his attention to removal of the bubble in the RV head. By spraying into the pressurizer, and then using the pressurizer heaters to strip the gas from solution, the gases will collect in the pressurizer. Ultimately the gases can be vented by using the pressurizer vent. Following the removal of the bubble from the RV head, the operator can then initiate a plant cooldown.

4.1.2 EFW and HPI Available

The initial primary system response for this case would be essentially the same as the described in Section 4.1.1 up to the point of using the RC pumps to sweep out the bubble in the hot legs. Without the RC pumps available, the hot leg vents can be opened to remove the trapped gases in the upper regions of the hot leg. Due to the continued injection of HPI, the liquid level would rise in the system and natural circulation would be restored. As noted before, gases trapped within the RV head will not prohibit the restoration of natural circulation.

A concern existed about the ability to depressurize the plant to cold shutdown conditions with a bubble trapped within the RV head. As the plant is depressurized, there was concern that expansion of the gas bubble from the RV head into the hot legs may cause an interruption of natural circulation. As described below, this problem has been examined and it has been concluded that plant depressurization could be performed without RV head vents, while maintaining natural circulation.

For non-pressurizer breaks, the primary system could be depressurized at a controlled rate using the pressurizer vent with the SGs being utilized to maintain subcooled conditions within the primary system.

The plant depressurization would allow the bubble in the RV head to expand into the hot leg. The depressurization rate would be controlled such that the volume of gas expanded into the hot legs is less than or equal to the volume of gas that could be removed by the open hot leg vents. In this manner, no significant gas accumulation will occur within the hot legs and natural circulation would be continuously maintained.

For breaks in the pressurizer, the pressurizer would remain full and the system pressure would stabilize at a value at which the injected ECC fluid matches the leak flow. The system could be depressurized at a controlled rate, as described above, by throttling the HPI while maintaining an adequate subcooling margin within the primary system. As described above, the gases expanded into the hot legs from the RV head would be bled out of the system through the open hot leg vents.

The methods described above allow for some of the gases trapped in the RV head to be expelled through the hot leg vents. However, they do not result in the complete elimination of the RV head gas bubble. Therefore, long term arrangements are needed for the removal of the reactor vessel bubble. This can be accomplished by many means, a few of which are:

1. Allow the reactor vessel head to cooldown naturally and condense the bubble.

2. Manual operation of the control rod drive mechanism (CRDM) to vent the noncondensible gases.

3. Use the letdown line to bleed fluid from the RCS, while providing makeup fluid to the system. This process will result in a decrease in the noncondensible concentration within the fluid thereby causing some of the trapped noncondensible gases in the RV head to dissolve in the coolant.

Since the bubbles in the RV head do not prohibit natural circulation nor operation of the decay heat removal system, longer term actions are acceptable.

For contrast, an assessment of operator actions with RV head vents has been performed. Since a bubble in the RV head does not prohibit reestablishment of natural circulation, only opening of the hot leg vents, as described previously, should be performed in order to reestablish natural circulation as soon as possible. Once natural circulation has been established and the primary system has regained subcooled margin, the operator could close the hot leg vents, open the RV head vents, and throttle HPI to maintain system pressure. In this manner, gases in the RV head can be expelled while the water level increases in the vessel. If the HPI is insufficient to maintain system pressure during this operation, the RV head vent should be closed with the system subcooling deecreases to $\approx$ 50 F. The primary system should then be repressurized to $\approx$ 1000 F subcooling and the procedure repeated until the bubble in the RV head is eliminated as indicated by a pressure increase in the system. Based on hand calculations for a .187 inch ID vent, the

expulsion of a bubble which completely fills the RV head would take at least 30 minutes for a pure hydrogen bubble and three hours for a steam bubble. Following the return of a completely solid primary system, with the exception of the pressurizer, the operator can then initiate a normal plant cooldown while using the HPI to maintain subcooling margin.

4.1.3 Just HPI Operating

The plant response for Category C break sizes without EFW available is somewhat different than described previously. The system will initially depressurize and initiate a reactor trip. The system depressurization would continue until the steam generator inventory is boiled-off and then a system repressurization would occur. Automatic actuation of the HPI may not occur prior to the generators boiling dry and manual initiation of HPI is required. The system pressure would ultimately increase to a point where the break alone is capable of removing the energy or it may reach the pressurizer relief and/or safety valve setpoints and be maintained at that pressure.

For these cases use of the hot leg vents to discharge steam could aid in the ultimate depressurization of the system. Depressurization of the RCS will be controlled by operator throttling of the HPI while maintaining subcooling in the system. A trapped gas bubble in the RV head does not prohibit plant depressurization nor will it interrupt natural circulation because natural circulation cannot be established without feedwater to the steam generator. This mode of operation would continue until the operator can reestablish EFWA at which time he would revert to the actions listed in either Section 4.1.1 or 4.1.2 depending on RC pump status.

4.2 Vent Usages for Inadequate Core Cooling Situations

During an inadequate core cooling situation, non-condensible gases may be released due to cladding rupture or metal-water reaction. Since the steam generators are utilized to depressurize the primary system and lead to subsequent actuation of the core flooding and/or low pressure injection systems, non-condensible gas concentrations within the steam generator should be minimized. It is expected that some of the non-condensible gases which may be generated collect within the RV head while the remainder will flow towards the steam generators. The trapped gases within the RV head need not be vented at this time as they do not interface with the SG heat removal. The gases which flow towards the SG can be removed by opening of the high point vents thereby minimizing the concentration of non-condensibles which reach the SG. Following core recovesry, the operation of the hot leg vents returns to the "normal" small break guidelines, described in Section 4.1.

REFERENCES

1. NUREG-0578, "Three Mile Island Lessons Learned Task Force Status Report and Short Term Recommendation," July, 1979.

2. Letter, H.R. Denton (NRC), "Resumption of Licensing Reviews for Nuclear Power Plants," August 20, 1979.

3. BAW-10103A, Rev. 3 "ECCS Analysis of B&W's 177 FA Lowered-Loop NSS," July, 1977.

4. Letter, J.H. Taylor (B&W) to S.A. Varga (NRC), July 18, 1978.

5. BAW-10075A, Rev. 1 "Multinode Analysis of Small Breaks for B&W's 177-Fuel-Assembly Nuclear Plants with Raised Loop Arrangement and Internal Vent Valves," March, 1976.

6. "Evaluation of Transient Behavior and Small Reactor Coolants Systsem Breaks in the 177 Fuel Assembly Plant," Babcock & Wilcox, May 7, 1979.

7. 69-1106001-00 "Small Break Operting Guidelines for Oconee 1, 2, and 3; Three Mile 1 and 2; Crystal River 3; and Rancho Seco 1," Babcock & Wilcox, November, 1979.

8. 69-1106002-00 "Small Break Operating Guidelines for Arkansas Nuclear 1," Babcock & Wilcox.

9. 69-1106003-01 "Small Break Operating Guidelines for Davis Besse 1," Babcock & Wilcox.

10. Letter, S.H. Duerson (B&W) to D.G. Slear (GPU) "Task 48, Task 62 and Task 63," GPU-80-0480, October 21, 1980.

NUCLEAR OPERATIONS

TECHNICAL ADVISOR

TRAINING PROGRAM

Prepared by: FLORIDA POWER CORPORATION

Submitted: January 31, 1981

NUCLEAR OPERATIONS TECHNICAL ADVISOR TRAINING PROGRAM

GOAL:

This program is designed to train Operations Technical Advisors able to promptly assess a complex array of indications and alarms associated with any off-normal operating events or accidents and immediately analyze the necessary actions to terminate or mitigate the consequences of the event. The Operations Technical Advisor must have the technical and analytical capability to recognize and react to a wide range of off-normal situations including multiple equipment failures, complex transient response, inadequate core cooling, and operator errors. His correct diagnosis and recovery recommendations will drastically reduce the likelihood of an event similar to Three Mile Island Unit 2.

OBJECTIVES:

Upon completion of this program the Nuclear Operations Technical Advisor must be capable of the following:

1. Evaluate the operating history of the plant (equipment failures, design problems, operator errors, etc.) and initiate corrective measures to prevent recurrence.
2. Review Licensee Event Reports from other nuclear plants similar in design to CR-3 and assure suitable dissemination of the evaluation to other plant staff members.
3. Analyze plant conditions required for maintenance activities and testing to assure adherence to Technical Specification requirements.
4. Develop and revise procedures to comply with state and federal regulations and to increase plant safety and efficiency.

5. Evaluate the adequacy of Operating Procedures to assure safe, continuous, normal operations and of Abnormal and Emergency procedures for mitigation capabilities during off-normal plant operations or accidents.
6. Review the recommendations of shift operating personnel and initiate modifications to increase plant safety and efficiency.
7. Provide diagnostic capabilities during off-normal operating events and advise the Shift Supervisor of actions necessary to mitigate or terminate the event.
8. Provide overall coordination of maintenance and refueling activities during planned and forced outages to minimize unit downtime and reduce man hours expended on outage tasks.
9. Prepare special reports in response to Quality Programs Audits, Compliance Audits, NRC Inspections or other operational reports as directed by the Operations Engineering Supervisor.
10. Evaluate the continuing adequacy of plant operations with regard to the assurance of quality and safety of operation consistent with Regulatory requirements.
11. Prepares Unusual Operating Events Reports after thorough review of strip chart recordings, computer alarm summary, and annunciator alarm summary and recommends changes to prevent recurrence.

PROGRAM CONTENT:

In general the program is to be presented in five phases, some running concurrently. The five phases are listed below as a general course content followed by detailed description of the program.

GENERAL CONTENT:

Phase I. College Level Fundamental Education.

Five quarters taught on site of basic academic material required as background for operations.

Phase II. Management Supervisory Skills and Administrative Controls.

Provided to bring the OTA's up to speed in Plant Administration and Management of personnel skills.

Phase III. Plant Systems (Primary, Secondary, Instrumentation and Control.

Provided to teach prospective OTA's plant systems, instruments controls and protection systems with which he can analyze plant status and the systems or tools with which to terminate transients or mitigate accidents.

Phase IV. General Operating Procedures, Emergency Procedures, Transient/Accident Analysis.

Provided so that the OTA has the capabilities to analyze plant transients and plan his way to get the plant back into a safe configuration.

Phase V. Simulator Training.

The culmination of the other phases allows the perspective OTA's to put their newly acquired skills to practice therefore driving them home.

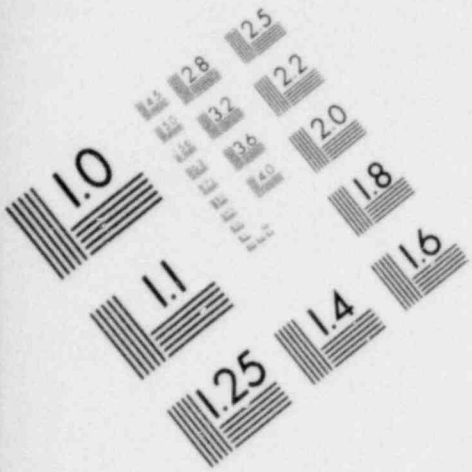
DETAILED CONTENT:

Phase I. College Level Fundamental Education.

STAP FIVE QUARTER COURSE SEQUENCE

41 CREDIT HOURS PLUS 5 HRS. PRACTICAL WORK

FUNDAMENTALS OF REACTOR SAFETY ENU RXSAF, 6 CR.	10 CR.	PRINCIPLES OF NUCLEAR POWER REACTOR OPERATIONS ENU 5176L, 4 CR.	5th Qtr.



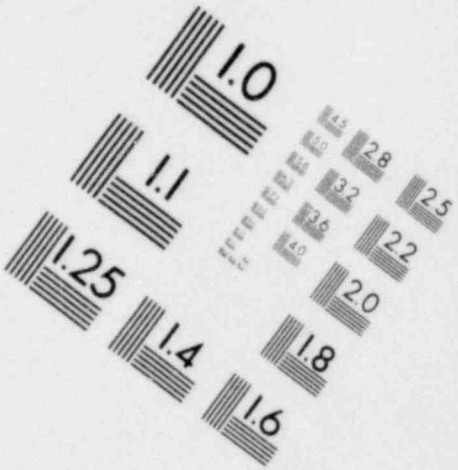
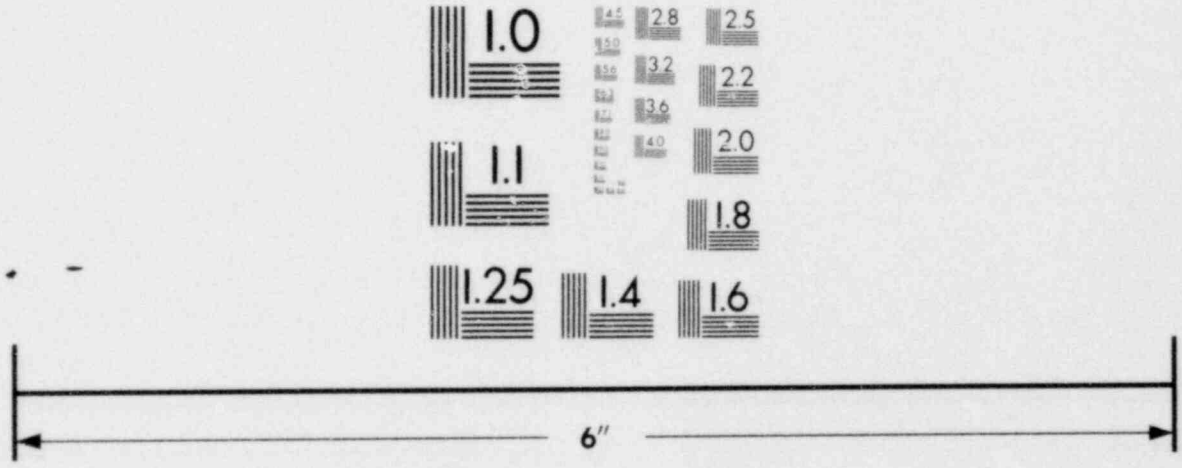
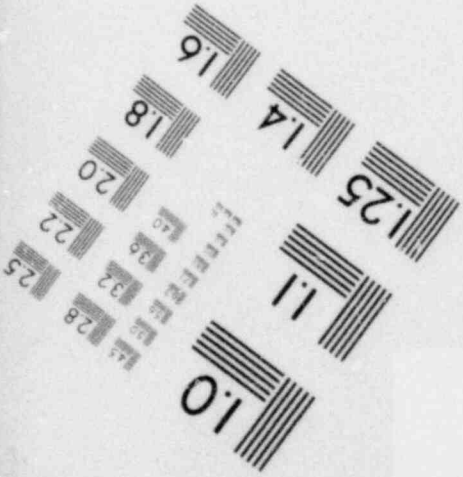


IMAGE EVALUATION
TEST TARGET (MT-3)





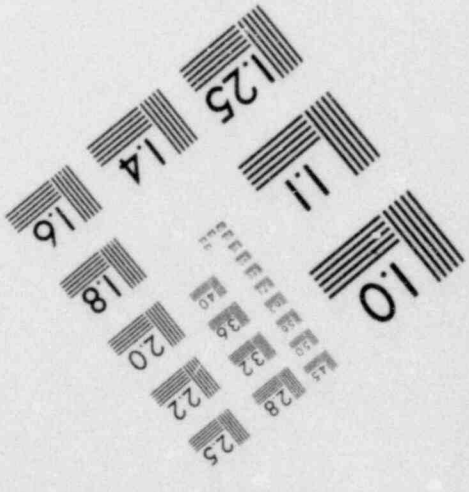
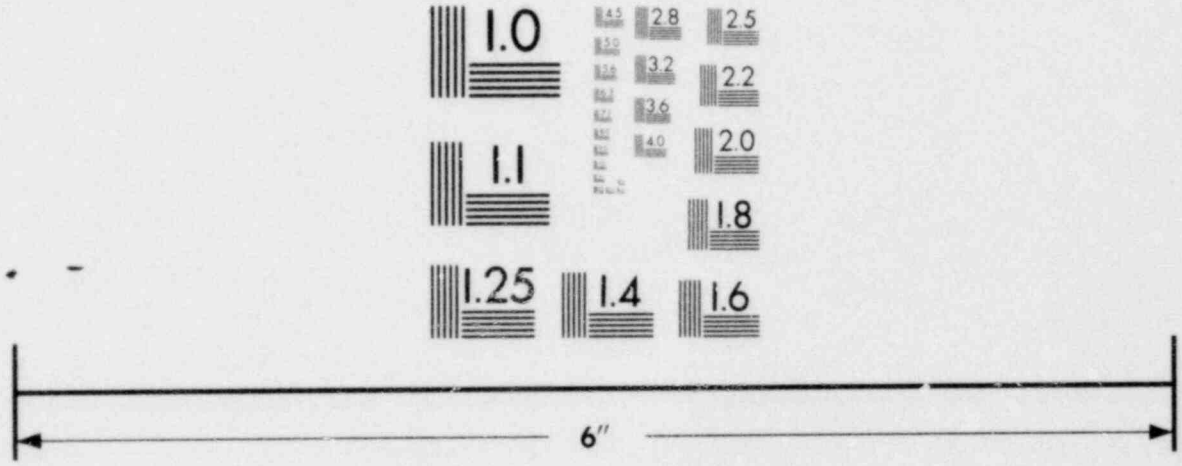
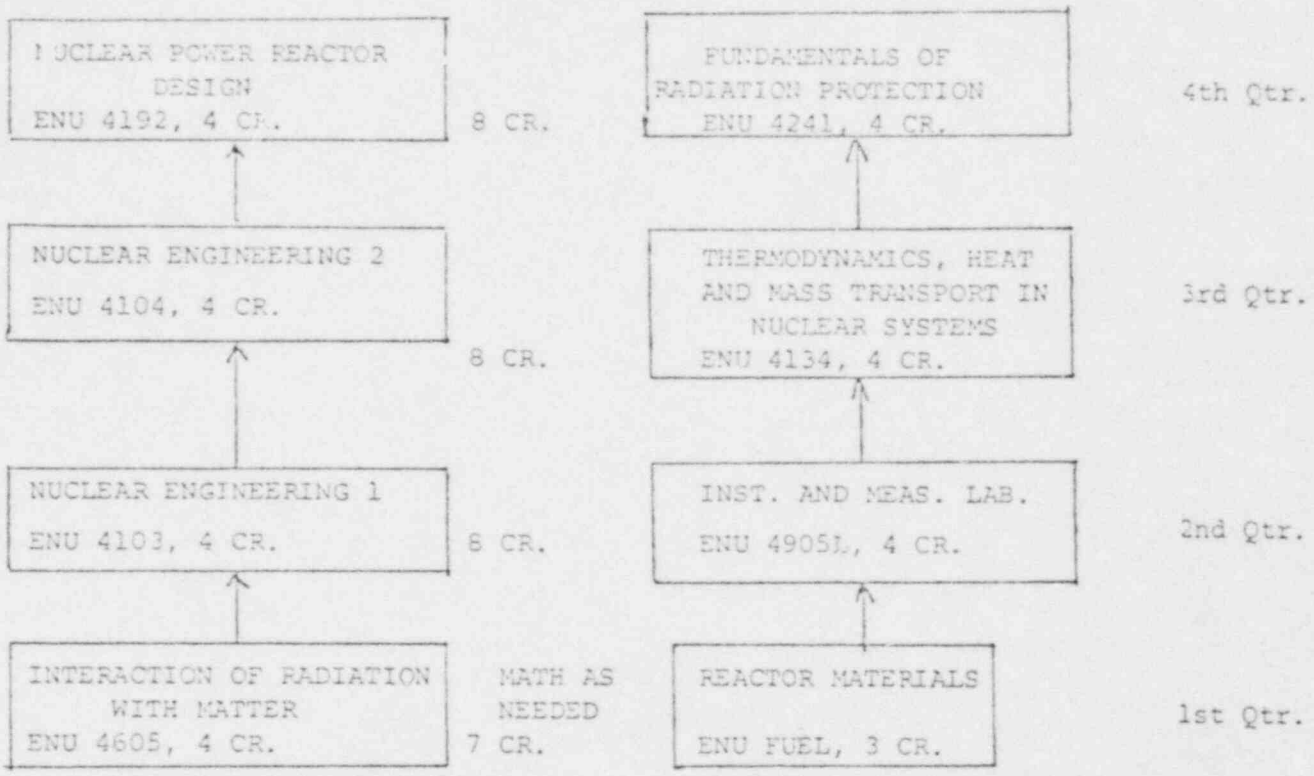


IMAGE EVALUATION
TEST TARGET (MT-3)





ALLOCATION OF STAP CREDITS
TO MEET INPO ACADEMIC REQUIREMENTS
(Quarter System Credits)

SUBJECT AREA	INPO CREDIT REQUIREMENTS	STAP PROGRAM CREDIT ALLOCATION
Mathematics	9	(6)*
Reactor Theory	10	10 as follows: ENU 4103 (4/4) ENU 4104 (3/4) ENU 4605 (1/4) ENU 4192 (1/4) ENU RXSAF (1/6)
Reactor Chemistry	3	3 as follows: ENU 5176L (2/4) ENU FUEL (1/3)
Nuclear Materials	4	4 as follows: ENU 4192 (1/4) ENU FUEL (2/3) ENU RXSAF (1/6)

SUBJECT AREA	INPO CREDIT REQUIREMENTS	STAP PROGRAM CREDIT ALLOCATION
Thermal Sciences	12	8 as follows:** ENU 4134 (4/4) ENU 4192 (2/4) ENU RXSAF (3/6)
Electrical Sciences	6	3 as follows:*** ENU 5176 (1/4) ENU 4905L (1/4) ENU 4605 (1/4)
Nuclear Instrumentation and Control	4	8 as follows: ENU 4605 (2/4) ENU 5176L (1/4) ENU RXSAF (1/6) ENU 4104 (1/4) ENU 4905L (3/4)
Nuclear Radiation Protection and Health Physics	4	ENU 4241 (4/4)

Phase II. Management Supervisory Skills and Administrative Controls.

A. Management Supervisory Skills

1. Leadership
2. Interpersonnel Communication
3. Motivation of Personnel Problem Analysis
4. Decisional Analysis
5. Command Responsibilities and Limits
6. Stress

B. Administrative Controls

1. Responsibilities for Safe Operation and Shutdown
2. Equipment Outages and Clearance Procedures

3. Use of Procedures

4. Plant Modifications

5. Shift Relief, Turnover and Manning

6. Access to Containment

7. Maintaining Cognizance of Plant Status

8. Unit Interface Controls (multi-unit plants with one or more units still under construction)

9. Physical Security

10. Control Room Access

11. Duties and Responsibilities of the STA

12. Radiological Emergency Plan

13. Code of Federal Regulations (appropriate sections)

14. Plant Technical Specifications

Phase III. Plant Systems (Primary, Secondary, Instrumentation and Controls).

1. Reactor Coolant System

2. Makeup and Purification

3. Decay Heat Removal

4. Chemical Addition and Sampling

5. Nuclear Service and Decay Heat closed cycle cooling water and raw water systems

6. Waste Disposal

   a. Gaseous

   b. Liquid

   c. Solid

7. Steam Generators

8. Main, auxiliary and reheat steam

9. Main turbine, Lubeoil and EHC

10. Condensate, Feedwater, and Emergency Feedwater

11. Secondary Service Cooling

12. Heater drains and vents

13. Air Systems

    a. Instrument

    b. Houseservice

14. Plant ventilation

15. Fire Service

16. Nuclear and Non-Nuclear Instrumentation

17. Plant computers

18. Integrated Control System

19. Reactor protection system

20. Engineered safeguards actuation system

21. Emergency Diesel Generators

22. Plant Distribution

    a. 500 KV to 480 Vac

    b. 480 V to 120 Vac

    c. DC Distribution and Batteries

    d. Protective relaying

Phase IV. General Operating Procedures, Emergency Procedures, Abnormal Procedures, Transient Analysis.

1. Review of selected normal plant operating procedures.

    a. Startup, heatup

    b. Power Operations

    c. Plant shutdown and cooldown

2. Emergency and Abnormal Operating Procedures.

3. Transient/Accident Analysis

   a. ATOG, TMI-2, Safety Analysis

   b. Planning and Use of Systems for Mitigation of Accidents

   c. Use of Recall, State Vector and other OTA Diagnostic tools

Phase V. Simulator Training.

Day 1

1. Introduction to the Course

   a. Role of the Shift Technical Advisor

   b. Philosophy of the Shift Technical Advisor

   c. Tools needed by the Shift Technical Advisor

2. Reactor Startup Discussion

   a. Review of applicable limits and precautions

   b. Review of technical specifications and their bases including minimum conditions for critical operations

   c. Review of Reactor Startup Procedure

3. Simulator Session

   a. Control Room familiarization

   b. Reactor Startup - all rods in to 10^{-8} amps (repeat as time permits)

Day 2

1. Plant Heatup and Cooldown

   a. Review of plant heatup and cooldown curves including the basis of the curves and applicable limits and precautions

   b. Review plant heatup procedures

   c. Review plant shutdown and cooldown procedures

2. Review of the Integrated Control System

   a. Control theory

   b. Basic subsystems

3. Simulator Session

   a. Reactor startup/plant heatup - Safety rods out to 15% power including turbine startup

   b. Plant shutdown and cooldown

Day 3

1. Review of the Integrated Control System

   a. Unit Load Demand

   b. Integrated Master

   c. Feedwater Subsystem

   d. Reactor Subsystem

2. Plant Maneuvering Response Using the ICS

   a. Operation during a Load Change

   b. Manual/Automatic Operations

3. Simulator Session

   a. Plant maneuver 15% to 100%, 100% to 15%

   b. Manual and Automatic operation of the ICS stations during plant maneuvers

Day 4

1. Review of Reactor Physics

   a. Subcritical Multiplication and Response

   b. Critical Response including Calculations

2. Reactivity Balance

   a. Review of reactivity coefficients

   b. Balance procedures

   c. Problem solving

3. Calculation of Estimated Critical Position

4. Simulator Session - Demonstration of Plant Transients

   a. Reactor Trip

   b. Load Rejection

   c. Loss of Normal Feedwater

   d. Solid Plant Operation

5. Loss of Off-Site Power - Demonstration of Natural Circulation

Day 5

1. Review of Abnormal and Emergency Procedures

   a. Reactor Trip

   b. Loss of Coolant

   c. Loss of Feedwater

   d. Loss of Feedpump

   e. Loss of One or More Reactor Coolant Pumps

   f. Steam Leaks

   g. OTSG Tube Leaks and Tube Ruptures

2. Simulator Session - Demonstration of Plant Transients

   a. Large RCS Leak

   b. Intermediate RCS Leak

   c. OTSG Tube Rupture

   d. Steam Leak

   e. Steam Line Rupture

Day 6

1. Thermodynamics Review

   a. Review of Definitions

      (1) Types of Energy

(2) Types of Systems

(3) Steady State and Equilibrium

b. Properties of Water

(1) Phase

(2) Saturation

(3) Superheat

(4) Subcooled

(5) Steam Tables

(6) Latent Heat of Vaporization

(7) Quality and Void Fraction

2. Heat Transfer Review

a. First Law of Thermodynamics and General Energy Equation

b. Use of the General Energy Equation to demonstrate the steady state heat balance of the:

(1) Primary System

(2) Secondary System

(3) OTSG

(4) Pressurizer

(5) Main Condenser

Note: These demonstrations should be developed by the student as guided by the instructor to demonstrate the fundamental concepts introduced above.

Day 7

Heat Transfer and Fluid Flow

1. Discuss heat transfer concepts

a. $\dot{Q} = \dot{M}Cp\Delta T$

b. $\dot{Q} = UA\Delta T$ or $hA\Delta T$ (OTSG and fuel assemblies)

c. $\dot{Q} = \dot{M}\Delta h$

2. Analyze the following plant transients using thermodynamics and heat transfer concepts (Instructor guided analysis)

   a. Loss of feedwater with and without emergency feedwater

   b. Reactor trip without turbine trip

   c. Steam line rupture

3. Discuss heat transfer mechanisms

   a. Forced convection - subcooled

   b. Forced convection - nucleate boiling - subcooled

   c. Forced convection - nucleate boiling - bulk boiling

   d. Film boiling

   e. Flow profiles

      (1) Annular flow

      (2) Slug flow

      (3) Chug flow

      (4) Flow with film boiling

      (5) Dryout

   f. Critical Heat Flux

      (1) DNB

      (2) Dryout

      (3) Variation of CHF with

         (a) Pressure

         (b) Temperature

         (c) Flow

         (d) Location

g. Natural Circulation

(1) Mechanics of natural circulation

(2) Factors affecting natural circulation

4. Plant examples demonstrating heat transfer mechanisms

a. Analyze small break LOCA to demonstrate (Instructor guided analysis)

(1) Energy loss thru the break

(2) Effects of HPI

(3) Effects of RCP

b. Analyze effects on natural circulation due to

(1) RCS saturation conditions

(2) OTSG level

(3) Aux vs normal feed path

(4) % RCS voiding

(5) RCS temperature

Day 8

1. Detailed Review of ICS

a. Signal flow paths

b. System response to normal operations

c. Calibrating integrals

2. Transient responses of the ICS

a. Load changes

b. Reactor trip

c. Rod drop

d. Loss of feedwater (Loss of MFP and loss of all feedwater)

e. RCP pump trip - RC flow degradation

f. Effects on transients with stations in manual

3. Reliability assessment of the ICS

4. Analyze loss of power transients (Instructor guided analysis)

   a. Off site

   b. ICS/NNI

Day 9

1. Derivation of Operating Limits

2. Derivation of RPS Setpoints

3. Safety Analysis

Day 10

1. Large LOCA analysis

2. Small break LOCA analysis

3. Inadequate core cooling analysis

Day 11

1. Transient Analysis

   a. Loss of feedwater with stuck open PORV (Instructor guided analysis)

      (1) With RCP's running

      (2) Without RCP's running

2. LOCA Guidelines

3. Simulator Session

   a. Reactor startup including ICS operation

   b. 5% steam leak

Day 12

1. Discussion of B&W Assessment Reports of Operating Plant Events and B&W development of Abnormal Transient Operating Guidelines.

2. Review of selected Operating Plant Events (Instructor guided analysis)

   a. Integrated Control System component failure

   b. Turbine Throttle Valve Transients

   c. Reactor Trip - Overcooling Event

Day 13

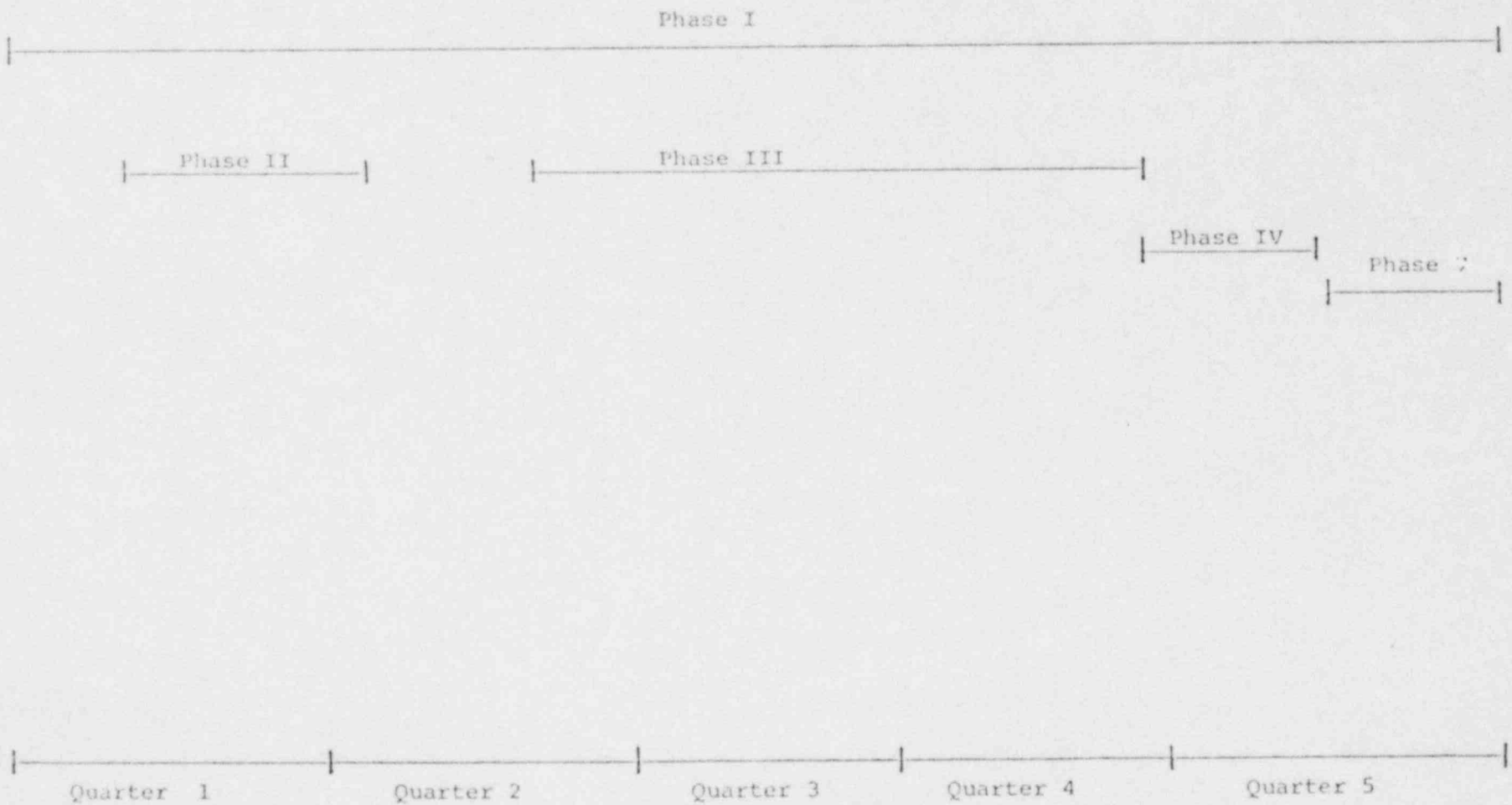
1. Analysis of TMI-2 Accident (Instructor guided analysis)
2. Simulator Sessions - Power operation with unannounced casualties
   a. Overfeed transient
   b. OTSG tube rupture

Day 14

1. Complete TMI-2 Accident Analysis
2. Transient Analysis of Loss of Feedwater - Reactor Trip - Loss of NNI Power Event (Instructor guided analysis)
3. Simulator Session - Power Operation with unannounced casualties
   a. Large steam break
   b. Loss of all feedwater

Day 15

1. Shift Technical Advisor Overview
   a. Analysis of selected plant parameters
   b. Use of plant instrumentation
   c. Limiting plant conditions
   d. Evaluation of heat sinks and core cooling
2. Drill Critiques
3. Simulator Session - Power Operation with unannounced casualties
   a. 0.01 ft^2 RC leak
   b. Failed pressurizer spray valve



SCHEDULE TIME QUARTERS

REPORT ON POWER-OPERATED RELIEF VALVE OPENING PROBABILITY AND JUSTIFICATION FOR PRESENT SYSTEM AND SETPOINTS

- Submitted to Satisfy Requirements of NUREG-0737, Items II.K.3.2 and II.K.3.7

Document No. 12-1122779 - Rev. 1

January 1981

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3.0 Conclusions

1.0 INTRODUCTION AND SUMMARY

NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980, required that a report be submitted which provides the information identified in Items II.K.3.2 and II.K.3.7. Specifically, NUREG-0737 requested the following information/justifications:

1. II.K.3.2

   - Compile operational data regarding pressurizer safety valves to determine safety valve failure rates

   - Perform a probability analysis to determine whether the modifications already implemented have reduced the probability of a small break LOCA due to a stuck-open PORV or safety valve a sufficient amount to satisfy the criterion ($<10^{-3}$ per reactor year), or whether the automatic PORV isolation system specified in Task Item II.K.3.1 is necessary.

2. II.K.3.7

   - Perform an analysis to assure that the frequency of PORV openings is less than 5% of the total number of overpressure transients.

This report is submitted in compliance with NUREG-0737 and demonstrates that the requirements of NUREG-0737 are met with the existing Power-Operated Relief Valve (PORV), Safety Valves and High Pressure Trip Setpoints and that no automatic isolation system is required.

2.1 Evaluation of PORV Opening Probability During an Overpressure Transient

An evaluation of the probability of PORV opening has been performed. Two separate analyses have been performed. The first is an analytical estimate, the second is an analysis based upon operating experience.

2.1.1 PORV Opening Probability Based Upon Analyses

A series of calculations have been completed using best estimate numbers to estimate the probability of PORV opening. Wherever possible, these calculations were based on operating plant data in an attempt to provide realistic estimates for the analyzed events. The following paragraphs summarize the results and calculational basis for the analysis.

The probability of the PORV lifting during a loss of feedwater (LOFW) or turbine trip is approximately 3.9×10^{-6}/Rx-Yr for plants with a PORV setpoint of 2450 psig and 3.9×10^{-3}/Rx-Yr for plants with a PORV setpoint of 2400 psig. The latter setpoint is presently applicable only to Davis-Besse 1. These probabilities are based on the assumptions that the high pressure trip setpoint is 2300 psig with a standard deviation of 1.4 psi and that the actual setpoint at which reactor trip occurs is a random variable which is normally distributed. The small standard deviation is based on the fact that the PORV and RPS actuation points are not completely independent; i.e., they share a common source; i.e., sensor and instrument string. Thus, these parts of the string errors are perfectly correlated and cancel one another in the analysis. Other parts of the relevant string error are not correlated and it is upon these that the 1.4 psi standard deviations are based. In a similar fashion, the

actual opening setpoint of the PORV is also assumed to be a random variable with a normal distribution. The assumption of normality for the actuation of either the high pressure trip or the PORV is just an assumption; no data is available to justify or deny the validity. The RCS pressure rise above the RPS high pressure trip setpoint (hence referred to as "pressure rollover") during a LOFW or turbine trip was determined by a combination of plant data and engineering analysis. Pressure rollover data from the operating plants (Table 2.1-1) was compiled from available data. However, these data points represent situations in which the PORV could open, thus decreasing the amount of pressure overshoot. Therefore, it was necessary to correct for the PORV opening, since we are interested in the situation in which it remains closed. This was accomplished by benchmarking the CADD code to a transient in which the PORV was isolated. After satisfactory duplication of this transient, the code was rerun modeling proper functioning of the PORV. The resulting pressure correction to the rollover data was 17.4 psi. The rollover data itself was tested and is statistically acceptable as normally distributed. It has a mean of 9.2 and a standard deviation of 27.52 psi. The presence of negative values in this data set indicates that the RPS trip setpoints have frequently been set low. Since the data reflects actual operating experience, the use of the negative values can be justified in the analysis.

Using the above data and assumptions, a Monte Carlo simulation of the relation

PORV - RPS - EXCESS - BIAS = SAMPLE

was conducted. The terms in the above relation are defined as follows:

PORV - PORV setpoint, a normally distributed random variable

RPS - High pressure trip setpoint, also a normally distributed random variable

EXCESS - Pressure rollover, a ~~randomly~~ normally distributed ~~normal~~ random variable

BIAS - A constant (17.4 psi) defined by analysis which compensates the rollover data for the fact that the PORV will remain closed.

Six thousand sample values of the above alogrithm expression were calculated using the SAMPLE code. A negative value of the above expression implies the PORV opens. In the computer trials, no negative values in 6000 instances were observed.

It was then assumed that the random variables described above are independent in the probabilistic sense, so an analytic approach was applied. The sum or difference of several independent normal distributions is also a normal distribution with mean equal to the algebraic sum of the means and standard deviation equal to the square root of the sum of variances. In this case, the mean is

$$2450 - 2300 - 9.23 - 17.4 = 123.37 \text{ (except DB-1, = 73.37)}$$

and standard deviation is

$$\sqrt{(1.4)^2 + (1.4)^2 + (27.52)^2} = 27.59 \text{ (for DB-1, = 27.59)}$$

The probability that the PORV will open during an overpressure transient is $3.9X10^{-6}$/Rx-Yr (for DB-1 this value is $3.9X10^{-3}$/Rx-Yr). The statistics show that we can be 99% confident that at least 99.99% of all LOFW and turbine trip high pressure transients will not open the PORV for the PORV set at 2450 psig. For a setpoint of 2400 psig, the statistics indicate a 99% confidence that more than 99.4% of the overpressure transients will not result in opening the PORV.

2.1.2 PORV Opening Probability Based Upon Operational Data

NUREG-0667, "Final Report of the B&W Reactor Transient Response Task Force," contained a listing of reactor trips (148) with PORV actuations prior to the TMI-2 accident. Since the accident at TMI-2 approximately 59 trips have occurred on B&W designed plants. Approximately 42 of these trips would have lifted the PORV with the old setpoints. Of the 190 trips that would have lifted the PORV with old setpoints, three of these events would have lifted the PORV with the new setpoints. In addition the modifications that have been made to the plants since those transients would have precluded PORV actuation given the same initiating events on those plants and the new setpoints. Based on these data, it is estimated that the present PORV opening probability is less than 1.6% for an overpressure transient, which is less than the 5% requirement stated in II.K.3.7 of NUREG-0737.

TABLE 2.1-1

PRESSURE ROLLOVER DATA

Trip #	Power, %	Peak Pressure, psig	Rollover, psig
1	95	2355	0
2	90	2385	+30
3	25	2400	+45
4	20	2385	+30
5	90	2390	+40
6	32	2345	-10
7	40	2360	+5
8	40	2352	-5
9	92	2375	+20
10	15	2365	+10
11	35	2400	+45
12	13	2370	+15
13	14	2355	0
14	38	2380	+25
15	98	2410	+55
16	72	2400	+45
17	100	2340	-15
18	100	2340	-15
19	100	2390	+35
20	100	2330	-25
21	98	2325	-30
22	15	2355	0
23	9	2370	+15
24	30	2345	-10
25	99	2350	-5
26	16	2295	-60

2.2 Evaluation of PORV and Safety Valve Reliability

2.2.1 Safety Valve Failure Rate History

There have been three cases where pressurizer safety valves were lifted on B&W plants. None of these cases resulted in failure of the safety valve to reseat. Because of the few data points, no estimate was made of the safety valve failure rates.

2.2.2 Evaluation of Small Break LOCA Probabilities/Need for PORV Isolation System

The contribution to the probability of a SB LOCA from an open PORV was estimated by two methods. The first was an analysis effort, the second was based strictly upon operational data. The results are discussed below:

2.2.2.1 Small Break LOCA Probability Calculations

The probability of a stuck open PORV is the product of the probability of being demanded open times the probability of failing open on demand. The raising of the PORV setpoint has reduced the number of demands and thus the probability of being in the stuck open state. The point estimate for PORV SB LOCA probability (variation not estimated) is calculated to be 5.04×10^{-4} per reactor year (5.48×10^{-4} for Davis Besse) which is less than the II.K.3.2 requirement of 1×10^{-3} per reactor year. The initiators of PORV actuations have been grouped into five categories along the associated frequency of each category. Details on how the values are calculated are contained in Table 2.2.2-1.

1. PORV opening on overpressure transient	3.9×10^{-6}/Rx-Yr
2. PORV opening on transient with delayed aux. feed	1.4×10^{-3}/Rx-Yr
3. PORV opening on operator action under ATOG guidelines	1.58×10^{-2}/Rx-Yr
4. PORV opening due to instrumentation control faults	5×10^{-3}/Rx-Yr
5. PORV opening from additional consideration from II.K.3.7	1.8×10^{-3}/Rx-Yr
TOTALS	2.40×10^{-2}/Rx-Yr 2.61×10^{-2}/Rx-Yr(DB)

This total is then multiplied by the probability of the PORV sticking open on demand.

Note that all plants except Davis Besse (Crosby PORV) have Dresser valves; however, the entire B&W operating plant experience was used to arrive at a generic PORV sticking open probability as follows: There have been ten stuck open PORV events, five of which could be classified as mechanical failure of the PORV (the other five were basically installation errors). Using all these five failures in determination of future frequency is considered conservative since two of the failures (OC-3,6/13/75 and CR-3, 11/75) were rectified by design changes, another (TMI-2, 3/28/79) cause is unknown. OC-2, 11/6/73 could be considered as a burn-in failure and the

DB-1, 10/13/77 event is a Crosby valve. Using five failures in 250 demands results in a value of 2×10^{-2} to fail to reclose on demand. This value is considered conservative not only due to the inclusion of all five failures but also the number of demands is probably much higher than 250. There have been 148 documented PORV openings on reactor trips; however, there is not a listing of PORV demands when the reactor did not trip (e.g., ICS runback) nor is consideration given to transients that could have actuated the PORV numerous times during an event. The value of 250 demands is conservatively used here. An analysis was also performed to include values for other than mechanical failure that keep the PORV open. The results of this analysis is summed with the mechanical contributor (2×10^{-2}/d) to arrive at the value for failure to reclose on demand (2.1×10^{-2}/d).

Probability of PORV small break LOCA equals:

$(2.4 \times 10^{-2})(2.1 \times 10^{-2}/d) = 5.04 \times 10^{-4}$/Rx-Yr

$(2.61 \times 10^{-2})(2.1 \times 10^{-2}/d) = 5.49 \times 10^{-4}$/Rx-Yr (DB)

2.2.2.2 Small Break LOCA Probability Based Upon Operational Data

As discussed in Section 2.1.2, there have been three events which with the revised setpoints would have actuated the PORV. However, the plants have been reconfigured (e.g., upgrades on aux. feedwater, control circuitry of PORV, NNI power sources, AC power sources) so as to reduce the probability of these PORV actuations. Conservatively estimating that one event could occur in the 45 years of B&W plant operation, yields a probability of occurrence of 2.22×10^{-2}/Rx-Yr.

The previous section gave a PORV failure probability of 2.1×10^{-2}/d. Therefore the probability of a PORV small break LOCA equals:

$$(2.22 \times 10^{-2} d/Rx\text{-}Yr)(2.1 \times 10^{-2}/d) = 4.7 \times 10^{-4}/Rx\text{-}Yr$$

which is less than the 1.0×10^{-3}/Rx-Yr criterion.

3.0 CONCLUSIONS

Both the analytical prediction and the estimate based on historical data result in values for a stuck open PORV from all causes which meet the requirements given in II.K.3.2. Note that no credit has been assigned for the operator closing the block valve given an open PORV. Analytical predictions (given proper auxiliary feedwater response) result in a value less than .01% of PORV openings for overpressure transients (taking into account the most limiting non-anticipatory trips) and historical data shows the frequency to be less than 1.6% which satisfies the criterion (less than 5%) specified in II.K.3.7.

Since the requirements of II.K.3.2 and II.K.3.7 are met with the current PORV configuration and set point it is not necessary to address the requirement for an automatic block valve closure system per II.K.3.1.

Table 2.2.2-1

1. The probability of a PORV opening on an overpressure transient from Section 2.1.1

for plants with PORV setpoint of 2450	3.9×10^{-6}/Rx-Yr
for plants with PORV setpoint of 2400 (DB)	3.9×10^{-3}/Rx-Yr

2. The PORV opening probability in a transient with delayed aux. feed

A value of 1.0 was assigned for PORV opening probability if aux. feedwater was not supplied. A value of 1.4×10^{-3}/Rx-Yr for loss of all feedwater was referenced from a B&W calculation which used average unavailability as calculated in the generic aux. feedwater reliability studies (BAW-1584) in conjunction with generic EPRI data on loss of main feedwater frequency and loss of offsite power frequency. 1.4×10^{-3}/Rx-Yr

On completion of the ongoing aux. feedwater reliability analysis (AP&L, SMUD, FPC) more specific values can be applied to those plants.

3. The PORV opening probability on operator action under ATOG guidelines

There are 3 events that call for operator opening of the PORV: a) Loss of All Feedwater. This contribution is already counted in 2 above; b) Small LOCA. Not applicable to

Table 2.2.2-1 (Cont'd)

this calculation since the plant is already in a small LOCA; c) Steam Generator Tube Rupture (considered smaller than small LOCA as defined in II.K.3.2 so argument of b) does not hold): The demand on the PORV given a tube rupture varies depending on whether offsite power is available or lost. If offsite power (Reactor Coolant Pumps) is available, only one PORV opening is required, whereas in the loss of offsite power scenario as many as 23 PORV openings are required.

The value calculated assumes that the probability of Steam Generator Tube Rupture considered with a LOOP event is small (no causal effect of LOOP or Steam Generator Tube Rupture) and therefore, the WASH-1400 of 1×10^{-3} for a LOOP given a reactor trip is used in the calculations. There have not been any tube ruptures in the cumulative B&W experience, (45 Rx-Yrs) due to the limited number of years experience. A Chi-square 50% confidence value with 0 failures is rather high (1.54×10^{-2} Rx-Yr).

Table 2.2.2-1 (Cont'd)

1.54×10^{-2}/Rx-Yr x 1 demand (offsite power available)	1.54×10^{-2}/Rx-Yr
1.54×10^{-2}/Rx-Yr x 10^{-3} Offsite Power Loss/Event x 23 demands (offsite power lost)	3.54×10^{-4}/Rx-Yr
	1.58×10^{-2}/Rx-Yr

In the final calculation of probability to reclose, it should be noted that no adverse effects of the 23 demands in the loss of offsite power case on PORV operability is assumed.

4. PORV opening due to instrumentation control faults

This has been estimated at 5×10^{-3}/ reactor year. This value assumes that power supply faults and other control deficiencies have been corrected by each utility. — 5×10^{-3}/Rx-Yr

5. PORV opening probability from additional considerations from II.K.3.7

There are overcooling transients that initiate HPI and operator failure to throttle or terminate flow before the PORV setpoint is reached. There have been 8 overcooling transients that initiated

Table 2.2.2-1 (Cont'd)

HPI in 392 reactor trips. The current frequency of reactor trips is 6 trips/Rx-Yr per plant. In this event sequence, the operator has approximately 4 minutes from time of HPI initiation until PORV setpoint is reached. The operator failure rate to terminate or throttle HPI flow is based on having ATOG in place (1.5×10^{-2}/d - based on NUREG-CR-1278 with moderately high stress). The overall probability of this sequence is therefore estimated to be 6 trips/Rx-Yr x 8/392 overcooling events/trip x 1.5×10^{-2} = 1.8×10^{-3} Rx-Yr

N.A. for DB

TOTALS 2.40×10^{-2}/Rx-Yr

2.61×10^{-2}/Rx-Yr (DB)

Note that these values are dominated by the conservative analysis of steam generator tube rupture. Analytical studies could be performed to obtain a more realistic value. Also note that the calculation for category 4 did not include operator or maintenance induced faults, such as the DB event of 10/27/80.

CONTROL ROOM

HABITABILITY

EVALUATION

1.0 Introduction

This report is an evaluation of the habitability of the Crystal River Unit 3 control room in compliance with NUREG-0737 Item III.D.3.4 This evaluation utilizes the results from the analyses of control room concentration for postulated accidental release of toxic gases, control room operator radiation exposures from airborne radioactive material, and direct radiation resulting from design basis accidents.

In addition to providing the results of the above analyses, the input data is presented in figure and table form with subsequent discussion of results and, where required, corrective measures.

2.0 Analyses

2.0.1 Analyses of Toxic Gas Hazards

Analyses of potential toxic gas hazards were performed in accordance with Standard Review Plan (SRP) 6.4 and applicable parts of Sections 2.2.1-2.2.2 and 2.23. The location of Crystal River chemical storage facilities is shown on Figure 1 and quantities are detailed on Table 1.

The results of these analyses for locations 1-11 resulted in the control room air intake concentrations below:

Chemical	Concentration at Control Room Intake	Toxicity Limit	Comments
Carbon Dioxide	0.15% by Volume	1% by Volume	Flash coeff. 0.472
Hydrogen			of plume, concentration expected ≈0
Nitrogen	0.1% by Volume	Asphyxiant <33% Volume	-
Sulfuric	≈0	2 mg/m^3	100° Vapor pressure <1 torr.

Failure of a liquid chlorine or anhydrous ammonia storage tank could result in a control room air intake concentration above toxicity limits, if worst case conditions are utilized. Accordingly, the design for installation of ammonia and chlorine detectors and an additional intake isolation damper is required to demonstrate habitability.

The remaining locations are under evaluation; however, it is not expected that these chemicals, with the exception of ammonia, would pose a hazard to control room habitability in the context of Regulatory Guide 1.78 requirements. For location 14, this ammonia storage would not impose any additional requirements above that of location 1.

As shown above, only failures of the chlorine or anhydrous ammonia storage vessels have the potential to result in toxic gas concentration in the control room that could, under discrete atmospheric conditions, exceed regulatory guidance. Based upon these findings, FPC has undertaken a design development program to: (1) install chlorine detectors, (2) install ammonia detectors, and (3) upgrade the intake isolation dampers. Estimates of procurement and installation schedules has identified completion during our 1983 refueling outage.

2.0.2 Analysis of Airborne Radioactive Material

The present analysis utilized source terms for a LOCA per Regulatory Guide 1.3. ESF leakage per SRP 15.556.5 App. B was considered and found to be a negligible contributor in comparison to containment leakage. Other design basis accidents were reviewed and found to be less severe hazards. Standard methods of calculation as found in the 13th AEC Air Cleaning Conference paper, K.A. Murphy and K. M. Campe (Reference 2) were used to perform the analyses.

The final rsults of the analysis indicate the following for the 30-day duration of the accident:

	Dose Limit (REM)	Calculated Dose (REM)
Whole-Body Gamma	5	2.67
Thyroid Inhalation	30	94.7 with 9600 CFM 28.7 with 2500 CFM
Beta Skin	30	18.1

As can be seen, the dose limit criteria of GDC 19, Appendix A of 10 CFR Part 50 and SRP 6.4, "Habitability Systems" are met provided air flow into the control room is throttled to 2500 CFM versus the present 9600 CFM.

Engineering work has been initiated to design a modification to limit air intake flow into the control room. Implementation of the above is expected to coincide with Section 2.0.1 modifiations.

2.0.3 Analysis of Direct Radiation

The analysis of control room direct radiation was presented in our January 11, 1980, letter in response to NUREG-0578 Item 2.1.6b. This analysis identified a dose rate of 11 mr/hr at time = 0 from direct radiation from the containment.

TABLE 1

LOCATION	CHEMICAL	QUANITY	DISTANCE FROM CR INTAKE (ft.)
1	Anhydrous Ammonia	8,500 lbs	3625
2	Carbon dioxide	12,000 lbs	3850
3	Chlorine	16 containers (2000 lbs ea.)	3600
4	Chlorine	8 containers (150 lbs. ea.)	4000
5	Hydrogen	12 Tubes (40.4 lbs. ea.)	4075
6	Hydrogen	12 Tubes (40.4 lbs. ea.)	4075
7	Nitrogen	11 containers (561 lbs. ea.)	4075
8	Sulfuric Acid	119,200 lbs. of 66° Be' H_2SO_4	4000
9	Sulfuric Acid	74,300 lbs. of 66° Be' H_2SO_4	3300
10	Sulfuric Acid	74,300 lbs. of 66° Be' H_2SO_4	3300
11	Sulfuric Acid	119,200 lbs. of 66° Be' H_2SO_4	3600
12	Sulfuric Acid	1000 gallons	440
13	Sodium Hydroxide	90,000 lbs.	440
14	Anhydrous Ammonia (2)	766 $Ft.^3$ ea.	440
15	Sulfuric Acid	8000 gallons	560
16	Sodium Hydroxide	8000 gallons	560
17	Nitrogen	141,000 Ft^3	204
18	Hydrogen	40,000 $Ft.^3$	500
19	Hydrogen	40,000 $Ft.^3$	730

Attachment 1

Control Room Habitability Evaluation

(1) Control Room mode of operation	Zone isolation, with filtered recirculated air, and a positive pressure maintained in the zone.
(2) Control Room characteristics	
(a) Air Volume Control Room	243,000 ft^3 (free)
(b) Control Room Emergency Zone	Elevation 145'-0" of the Control Complex
(c) Control Room ventilation system schematic	See Attachment 2
(d) Infiltration leakage rate	9600 CFM (existing) 2500 CFM (after modification)
(e) Filter Efficiencies	
1. Charcoal filters 2. HEPA filters	95% for all species of iodine
(f) Closest distance between containment and air intake	88 ft.
(g) Layout drawing	See Figure 3
(h) Control Room shielding	11 mr/hr at T = 0 (Ref. Jan. 11, 1980 submittal)
(i) Automatic isolation capability	
1. Damper closing time	3-5 sec.
2. Damper leakage	.5% of air intake
3. Damper area	~24 ft^2
(j) Chlorine detectors	None
(k) Self-continued breathing apparatus availability	2
(l) Bottled air supply	2 spare for above
(m) Emergency food supply Emergency portable water supply	7 days None
(n) Control Room personnel capacity	4 to 20
(o) Potassium iodine drug supply	None

(3) On-site storage of chlorine and other hazardous chemicals

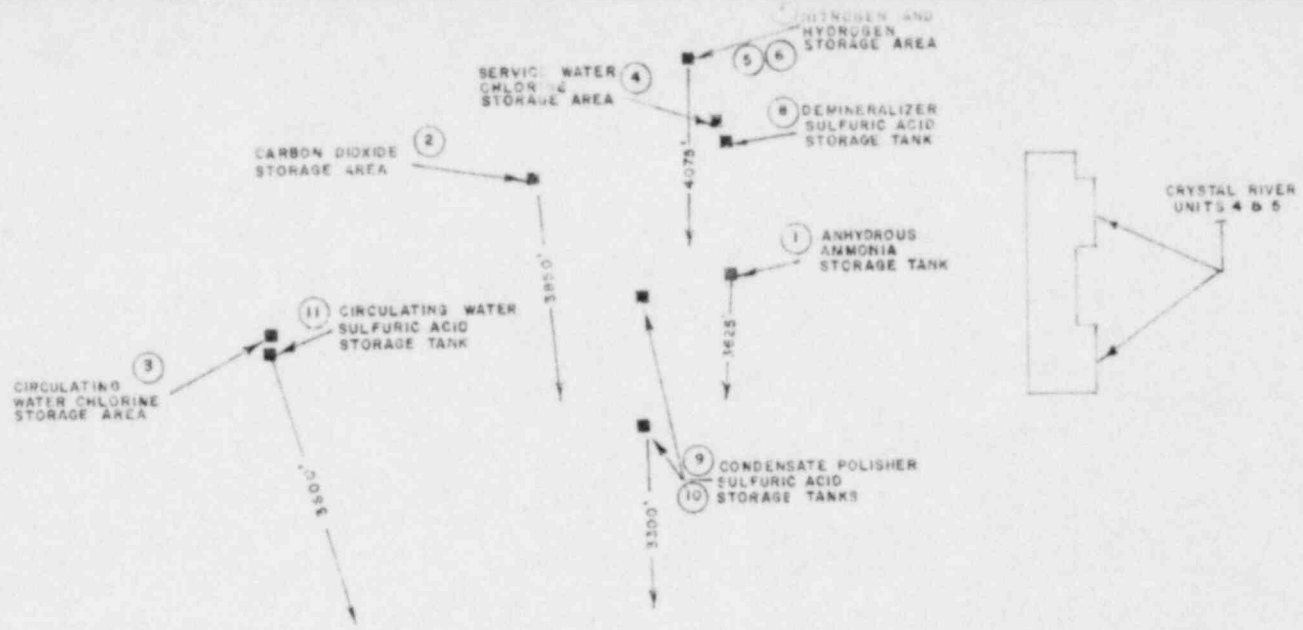
(a) Total amount and size	See Table 1
(b) Closest distance from Control Room air intake	See Table 1

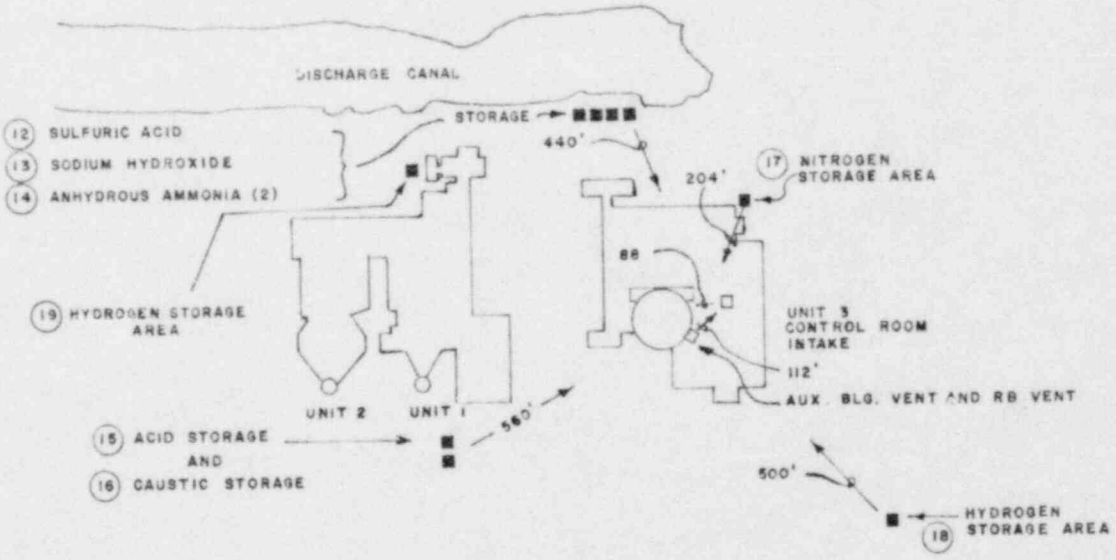
(4) Off-site manufacturing, storage or transportation facilities of hazardous chemicals

(a) Identify facilities with a 5-mile radius	
(b) Distance from Control Room	See FSAR Section 2.2.3
(c) Quantity of hazardous chemicals in one container	
(d) Frequency of hazardous chemical transportation traffic (truck, rail, and barge)	

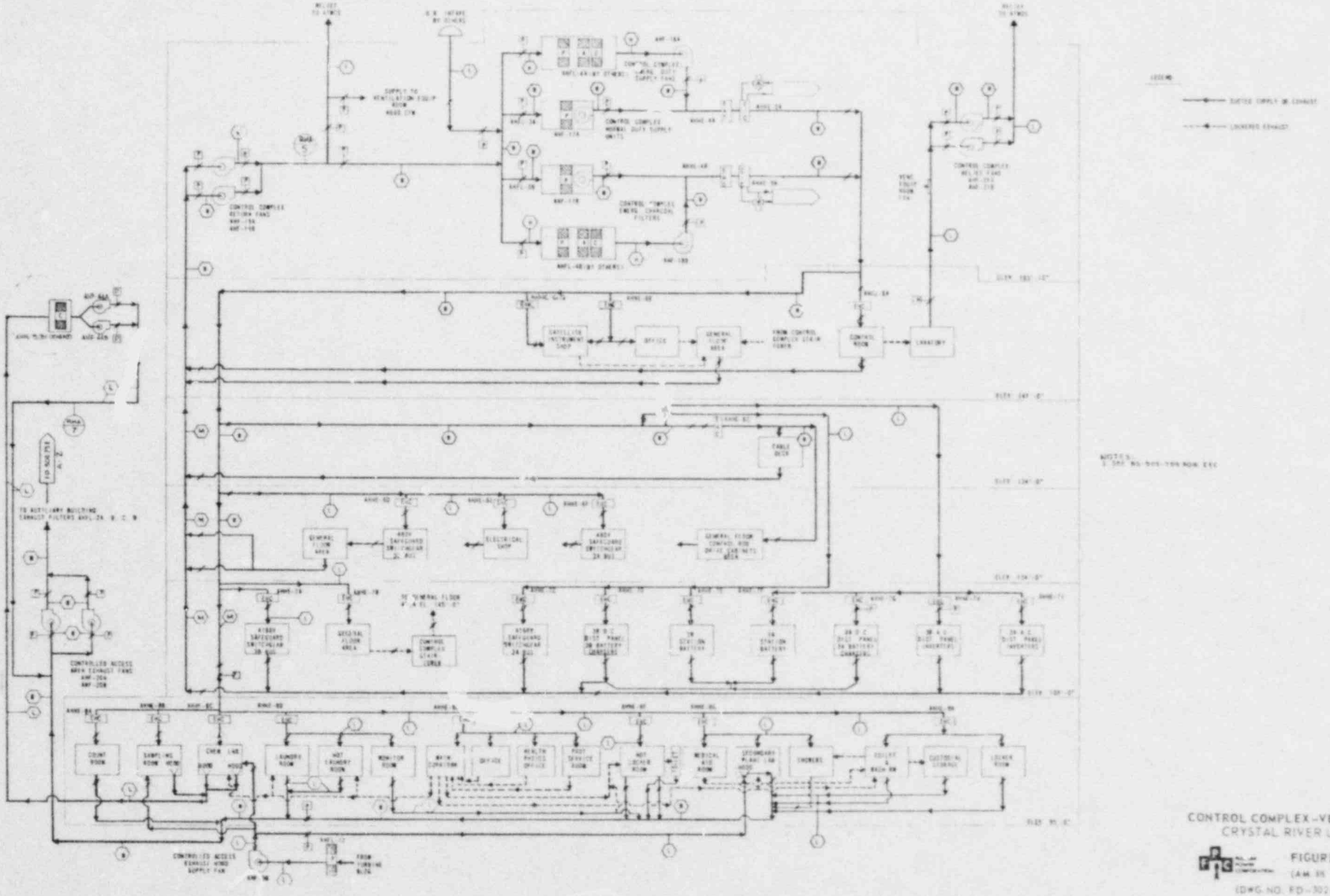
(5) Technical specifications (refer to standard technical specifications)

(a) Chlorine detection system	None
(b) Control Room filtration system including the capability to maintain the Control Room pressurization at 1/8 in. water guage, verification of isolation by text signals and damper closure times, and filter testing requirements.	





HAZARDOUS CHEMICALS
STORAGE LOCATIONS
CRYSTAL RIVER PLANT
FIGURE 1



CONTROL COMPLEX-VENTILATION
CRYSTAL RIVER UNIT 3

FIGURE 9-12
(AM 95 1-78)
(DWG. NO. FD-302-753)

BAW-1648

November 1980

THERMAL-MECHANICAL REPORT — EFFECT OF HPI ON VESSEL INTEGRITY FOR SMALL BREAK LOCA EVENT WITH EXTENDED LOSS OF FEEDWATER

Applicable to

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Nuclear Steam Systems

DUPLICATE

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