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U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Attention: Charles L. Miller, Director
Standardization and Non-Power Reactor Project Directorate

Subject: **Resolution of Outstanding ABWR SSAR Issues**

Enclosed are thirty four (34) copies of the resolution of outstanding ABWR Standard Safety Analysis Report (SSAR) issues resulting from the May 31,1989 and June 1,1989 GE/NRC meeting in San Jose. The resolution of the issues is provided in Attachment 1 in the form of changes to the SSAR which GE intends to amend in the near future.

Also included in this transmittal is Attachment 2 which summarizes our proposed new Chapter 15 analysis for events impacted by the implementation of two motor-generator sets and our plans to provide additional of the classification of selected events. Attachment 2 includes a summary description of these motor-generator sets.

Finally, Attachment 3 provides a draft amendment to the SSAR which updates Subsection 5.4.5, "Main Steamline Isolation System". The major change is in the main steam isolation valve (MSIV). Following an extended and thorough review of MSIV operating experience by the Japanese ABWR Project, the decision was made to use the MSIV design installed in current operating BWRs and apply the improvements to this basic design which have been demonstrated in Japan.

Sincerely,

P. W. Marriott, Manager
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ATTACHMENT 1

RESOLUTION OF OUTSTANDING ABWR SSAR ISSUES

Section	Subject
3.1.2 & 9.3.5	Standby liquid control system
4.6	Fine motion control rod drive
5.2.2	Overpressure protection
5.2.5	Leak detection
5.4.6 & 9.2.9	Reactor core isolation cooling system
5.4.7	Residual heat removal system
6.2.6	Containment leakage testing
6.3.3	Emergency core cooling system
9.3.5	Standby liquid control system
App. 1A	TMI action plan items

(5) 7.2 Reactor Trip System

(6) 7.7.1.2 and 7.7.2.2 Rod Control and Information System - Instrumentation and Controls

(7) 15 Accident Analyses

3.1.2.3.7 Criterion 26 - Reactivity Control System Redundancy and Capability

3.1.2.3.7.1 Criterion 26 Statement

Two independent reactivity control systems ofdifferent design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure that acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

3.1.2.3.7.2 Evaluation Against Criterion 26

Two independent reactivity control systems utilizing difference design principles are provided. The normal method of reactivity control employs control rod assemblies which contain boron carbide (B4C) powder. Positive insertion of these control rods is provided by means of the control rod drive electrical and hydraulic system. The control rods are capable of reliably controlling reactivity changes during normal operation (e.g., power changes, power shaping, xenon burnout, normal startup and shutdown) via operator-controlled insertions and withdrawals. The control rods are also capable of maintaining the core within acceptable fuel design limits during anticipated operational occurrences via the automatic scram function. The unlikely occurrence of a limited number of stuck rods during a scram will not adversely affect the capability to maintain the core within fuel design limits.

The circuitry for manual insertion or withdrawal of control rods is completely independent of the circuitry for reactor scram. This separation of the scram and normal rod control functions prevents failures in the reactor manual-control circuitry from affecting the scram circuitry. Two sources of energy (accumulator pressure and electrical power to the motors of the fine motion control rod drives, FMCRDs) provide needed control rod insertion performance over the entire range of reactor pressure (i.e., from operating conditions to cold shutdown). The design of the control rod system includes appropriate margin for malfunctions such as stuck rods in the unlikely event that they do occur. Control rod withdrawal sequences and patterns are selected prior to operation to achieve optimum core performance and, simultaneously, low individual rod worths. The operating procedures to accomplish such patterns are supplemented by the rod pattern control system, which prevents rod withdrawals yielding a rod worth greater than permitted by the preselected rod withdrawal pattern. Because of the carefully planned and regulated rod withdrawal sequence, prompt shutdown of the reactor can be achieved with the insertion of a small number of the many independent control rods. In the event that a reactor scram is necessary, the unlikely occurrence of a limited number of stuck rods will not hinder the capability of the control rod system to render the core subcritical.

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~~The second independent reactivity control system is provided by the reactor recirculation system. By varying reactor coolant flow, it is possible to effect the type of reactivity changes necessary for planned, normal power changes (including xenon burnout). In the unlikely event that reactor flow is suddenly increased to its maximum value (pump runout), the core will not exceed fuel design limits because the power flow map defines the allowable initial operating states so that the pump runout will not violate those limits.~~

The control rod system is capable of holding the reactor core subcritical under cold conditions, even when the pair of control rods of highest worth controlled by an hydraulic control unit is assumed to be stuck in the fully withdrawn position. This shutdown capability of

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A standby liquid control system containing a neutron-absorbing sodium pentaborate solution is the independent backup system. This system has the capability to shut the reactor down from full power and maintain it in a subcritical condition at any time during the core life. The reactivity control provided to reduce reactor power from rated power to a shutdown condition with the control rods withdrawn in the power pattern accounts for the reactivity effects of xenon decay, elimination of steam voids, change in water density due to the reduction in water temperature, Doppler effect in uranium, change in neutron leakage from boiling to cold, and change in rod worth as boron affects the neutron migration length.

the control rod system is made possible by designing the fuel with burnable poison (Gd_2O_3) to control the high reactivity of fresh fuel. ~~In addition, the standby liquid control system is available to add soluble boron to the core and render it subcritical as discussed under the evaluation against Criterion 27.~~

The redundancy and capabilities of the reactivity control systems for the BWR satisfy the requirements of Criterion 26.

For further discussion, see the following sections:

	Chapter/ Section	Title
(1)	1.2.1	Principal Design Criteria
(2)	4.6	Functional Design of Reactivity Control Systems
(3)	7.3	Engineered Safety Feature Systems
(4)	7.4.1.2 and 7.4.2.2	Standby Liquid Control System - Instrumentation and Controls
(5)	7.7.1.2 and 7.7.2.2	Rod Control and Information System - Instrumentation and Controls

3.1.2.3.8 Criterion 27 - Combined Reactivity Control Systems Capability

3.1.2.3.8.1 Criterion 27 Statement

The reactivity control systems shall be designed to have a combined capability in conjunction with poison addition by the emergency core cooling systems of reliably controlling reactivity changes to assure that, under postulated accident conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained.

3.1.2.3.8.2 Evaluation Against Criterion 27

There is no credible event applicable to the ABWR which requires combined capability of the control rod system and poison additions. The ABWR design is capable of maintaining the reactor core subcritical, including allowance for a pair of stuck rods controlled by an hydraulic control unit (HCU), without addition of any poison to the reactor coolant. The primary reactivity control system for the ABWR during postulated accident conditions is the control rod system. Abnormalities are sensed, and, if protection system limits are reached, corrective action is initiated through automatic insertion of control rods. High integrity of the protection system is achieved through the combination of logic arrangement, actuator redundancy, power supply redundancy, and physical separation. High reliability of reactor scram is further achieved by separation of scram and manual control circuitry, individual HCU controlling a pair of control rods, and fail-safe design features built into the rod drive system. Response by the reactor protection system is prompt and the total scram time is short.

In the very unlikely event that more than one control rod fails to insert and the core cannot be maintained in a subcritical condition by control rods alone as the reactor is cooled down subsequent to initial shutdown, the standby liquid control system (SLCS) can be actuated to insert soluble boron into the reactor core. The SLCS has sufficient capacity to ensure that the reactor can always be maintained subcritical; and, hence, only decay heat will be generated by the core which can be removed by the RHR System, thereby ensuring that the core will always be coolable.

The design of the reactivity control systems assures reliable control of reactivity under postulated accident conditions with appropriate margin for stuck rods. The capability to cool the core is maintained under all postulated accident conditions; thus, Criterion 27 is satisfied.

For further discussion, see the following sections:

nuclear system safety/relief valves begin to relieve pressure above approximately 1100 psig. Therefore, the SLCS positive displacement pumps cannot overpressurize the nuclear system.

Only one of the two standby liquid control pumps is needed for system operation. If a redundant component (e.g., one pump) is found to be inoperable, there is no immediate threat to shutdown capability, and reactor operation can continue during repairs. The time during which one redundant component upstream of the injection valves may be out of operation should be consistent with the following: the probability of failure of both the control rod shutdown capability and the alternate component in the SLCS; and the fact that nuclear system cooldown takes several hours while liquid control solution injection takes approximately two-and-one-half hours. Since this probability is small, considerable time is available for repairing and restoring the SLCS to an operable condition while reactor operation continues. Assurance that the system will still fulfill its function during repairs is obtained by demonstrating operation of the operable pump.

The SLCS is evaluated against the applicable General Design Criteria as follows:

Criterion 2: The SLCS is located in the area inside the secondary containment, outside drywell and below the refueling floor. In this location, it is protected by the containment and compartment barriers from external natural phenomena such as earthquakes, tornadoes, hurricanes and floods and internally from effects of postulated events (e.g., DBA-LOCA).

Criterion 4: The SLCS is designed for the expected environment in the secondary containment and specifically for the area in which it is located. In this area, it is not subject to the more violent conditions postulated in this criterion such as missiles, whipping pipes, and discharging fluids.

Criterion 21: Criterion 21 is applicable to protection systems only. The SLCS is a reactivity control system and should be evaluated against Criterion 29.

Criterion 26: The SLCS is the second reactivity control system required by this criterion. ~~The requirements of this criterion do not apply within the SLCS itself~~.

Criterion 27: This criterion applies no specific requirements onto the SLCS and therefore is not applicable. See the General Design Criteria Section for discussion of combined capability.

Criterion 29: The SLCS pumps and valves outboard of the outboard drywell check valve are redundant. Two suction valves, two pumps, and two injection valves are arranged and crosstied such that operation of any one of each results in successful operation of the system. The SLCS also has test capability. A special test tank is supplied for providing test fluid for the yearly injection test. Pumping capability, injection valve operability and suction valve operability may be tested at any time.

The SLCS is evaluated against the applicable regulatory guides as follows:

Regulatory Guide 1.26: Because the SLCS is a reactivity control system, all mechanical components are at least Quality Group B. Those portions which are part of the reactor coolant pressure boundary are Quality Group A. This is shown in Table 3.2-1.

Regulatory Guide 1.29: All components of the SLCS which are necessary for injection of neutron absorber into the reactor are Seismic Category I. This is shown in Table 3.2-1.

ASB 3-1 and MEB 3-1

Since the SLCS is located within its own compartment inside the secondary containment, it is adequately protected from flooding, tornadoes, and internally/externally generated missiles. SLCS equipment is protected from pipe break by providing adequate distance between the seismic and nonseismic SLCS equipment, where such protection is necessary. In addition, appropriate distance is provided between the SLCS and other high energy piping systems.

QUESTION 440.105

We understand that boron mixing tests were performed for optimizing the location of boron injection. Describe the test criteria and the test results. (9.3.5)

RESPONSE 440.105

Boron mixing tests were performed in a 1/6 scale three dimensional model of ABWR with reactor internal pumps. In these tests, the overhead type high pressure core spray sparger was used as the primary injection location. Injection at the reactor internal pump suction was examined as a backup location. The objective of the tests was to understand the mixing phenomenon when a boron solution is injected into the reactor coolant, and to determine the mixing coefficient, n, which is a measure of the mixing efficiency or effectiveness as defined as:

$$n = \frac{\text{Concentration of injection solution at a measured location (region of the model)}}{\text{Concentration if well mixed with entire model inventory}}$$

A coefficient of unity thus represented the equivalent of a completely mixed solution. Incomplete mixing was characterized by coefficients less than unity in some regions of the model and greater than unity in others. Transit time is defined as the time required for the injected solution to travel from the point of injection to the region of interest.

Based on the data analyses, the following conclusions were drawn:

(1) Boron injected through HPCF will reach the core in all conditions including time after hot shutdown. No stratification was found anywhere in the vessel for all the tests.

(2) HPCF is the recommended injection location. If HPCF were not the design basis, injection through four recirculation pump suction locations will also provide good mixing.

QUESTION 440.106

In SSAR Section 9.3.5.3, under criterion 26, it is stated that "The requirements of this criterion do not apply within the SLCS itself." Elaborate on this assumption. (9.3.5)

RESPONSE 440.106

The identified statement has been removed.

~~Criterion 26 states that two independent reactivity control systems are required. SLCS satisfies the criterion of being an "independent reactivity control system"; however, it does not satisfy the requirements that "one of the systems shall use control rods" or that "the second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout)". The first requirement is of course satisfied by the control rod system. The second requirement is satisfied by the recirculation system by varying the recirculation flow rate. Therefore, even though the SLCS is an independent reactivity control system "the requirements of this criterion do not apply within the SLCS itself."~~

QUESTION 440.107

In SSAR Section 9.3.5.3, under criterion 27, it is stated that "this criterion applies no specific requirements onto the SLCS and therefore is not applicable." Describe in detail the justification for the above statement. (9.3.5)

QUESTION 440.4

In Figure 4.6-8a, CRD system P&ID, sheet 1, piping quality classes AA-D, FC-D, FD-D, FD-B, etc. are shown. Submit the document which explains these classes and relates them to ASME code classes.

RESPONSE 440.4

This information is scheduled to be included in Section 1.7. Essentially, the first two letters of the codes specify the pipe primary pressure rating (150 lb., 900 lb., etc.) the type of service (condensate or reactor water, steam, etc.), and material (carbon or stainless steel). The symbols "A", "B" and "C" represent ASME Section III, code Classes 1, 2, and 3, respectively. The symbol "D" represents ASME Section 8, or ANSI B31.1 or other equivalent codes.

QUESTION 440.5

In Figure 4.6-8b, the leak receiver tank is shown. What is the function of this tank? How big is this tank? Will a high level in the tank impact the operation of the control rod drive?

RESPONSE 440.5

This leakage collection tank is no longer part of the design. The intent of the leakage collection system was to assist the operator in identifying which drives were potential candidates for seal replacement during plant outages, which would facilitate plant maintenance planning. However, the design could not provide the level of differentiation of leakage between individual drives needed for this purpose and was therefore deleted. An updated P&ID (Figure 4.6-8b) will be provided by December 31, 1988 to document this change.

QUESTION 440.6

Identify the essential portions of the CRD system which are safety related. Confirm that the safety related portions are isolable from non-essential portions. (4.6)

RESPONSE 440.6

The essential portions of the CRD system which are safety-related are:

(a) The hydraulic control units (HCUs),

(b) The scram insert piping from the HCUs to the fine motion control rod drives (FMCRDs), and

(c) The FMCRDs (except the motors)

The non-essential portions of the CRD system interface with the essential portions at the following connections to the HCUs:

(a) The accumulator charging water line

(b) The FMCRD purge water line, and

(c) The scram valve air supply from the scram air header.

The safety-related portions of the HCU and the scram function are protected against failure in the non-essential portions of the charging water and purge water lines by check valves. Also, instrumentation in the charging water line provides signals to the reactor protection system to cause reactor scram in the event of loss of charging water pressure. Loss of pressure in the scram air header causes the scram valves to actuate, resulting in reactor scram. This fail-safe feature is the same as provided on current BWR designs using locking piston-type control rod drive.

INSERT B

QUESTION 440.7

In the old CRD system, the major function of the cooling water was to cool the drive mechanism and its seals to preclude damage resulting from long term exposure to reactor temperatures. What is the function of purge water flow to the drives? (4.6)

RESPONSE 440.7

The function of the purge water flow to the fine motion control rod drives is to prevent reactor water from entering the drive housing during operation. This will minimize crud buildup in the drive housing and reduce operator exposure during drive maintenance.

QUESTION 440.8

We understand that the LaSalle Unit 2 fine motion control rod drive demonstration test is still in progress. Submit the test results as soon as it is available.

RESPONSE 440.8

At the current time, the LaSalle Unit 2 fine motion control rod drive demonstration test is expected to be terminated in October 1988. The final report for the FMCRD In-Plant Test Program, which will include the LaSalle Test results, will be formally issued in September 1989.

QUESTION 440.9

In the present CRD system design, the ball check valve ensures rod insertion in the event the accumulator is not charged or the inlet scram value fails to open if the reactor pressure is above 600 psig. Confirm that this capability still exists in the ABWR design. (4.6)

RESPONSE 440.9

The ABWR control rod design does not have the capability of the locking piston control rod design to insert hydraulically using reactor pressure in the event of a failure in the hydraulic control units (i.e., scram valve fails or accumulator is not charged). However, the fine motion control rod drive (FMCRD) has a diverse means of inserting the control rod using electric motor run-in if hydraulic scram fails. This feature provides the FMCRD with the capability to insert the control rod over the entire range of reactor operating pressures.

QUESTION 440.10

In section 4.6.2.3.1, it is stated the scram time is adequate as shown by the transient analyses of Chapter 15. Specify the scram time. (4.6.2.3.2.1)

(B)

The FMCRD provides the following functions:

1. Normal rod positioning in response to commands from the Rod Control and Information System

2. Rapid control rod insertion (scram)

3. Scram follow function (post-scram electric motor run-in)

4. ATWS FMCRD run-in, and

5. Selected control rod run-in (for stability control).

Of these, only the hydraulic scram function (Item 2) is classified as a safety-related function. The other functions, all of which involve positioning the rods by means of the FMCRD electric motors, are designed for high reliability but are not classified as safety-related. Therefore, because the FMCRD motor does not perform a safety-related function, it is classified as non-Class 1E.

With respect to ATWS in particular, the FMCRD run-in function is considered an ATWS mitigating system. As such, the NRC design guidance regarding system and equipment specifications for 10CFR50.62, as defined in the Federal Register, Volume 49, No. 124, pg 26042 (dated 6/26/84), was applied. This guidance states that the ATWS mitigating systems are not required to be safety-related; therefore, the FMCRD motors are not required to be Class 1E.

However, the automatic FMCRD run-in function for ATWS is designed to provide high reliability. Some features to be noted are:

1. FMCRD run-in provides means of control rod insertion that is diverse from the hydraulic insertion of both the normal scram (RPS generated) and ATWS ARI (venting of scram air header). Both of these independent functions must fail before FMCRD run-in is needed to shut down the reactor.

2. The automatic FMCRD run-in utilizes initiation signals (high reactor pressure or low reactor water level 2) which are diverse from the RPS.

3. The FMCRD run-in controls and instrumentation are powered from non-divisional, non-interruptible DC power independent from RPS power.

4. The FMCRD motors are connected to the divisional power buses which are connected to the emergency diesel generators. This allows FMCRD run-in during any loss-of-offsite power event. The divisional power assignments throughout the core for the FMCRD motor power supplies are in a "checkerboard" pattern. This arrangement provides the capability to achieve hot shutdown even with failure of offsite power and one of the diesel generators (a degraded ATWS condition beyond the design basis). Under these

(B) (CONTINUED)

circumstances the operator would have time to reestablish offsite power or startup of the failed diesel generator to achieve cold shutdown. As a last resort, manual initiation of the SLCS would always be available to achieve cold shutdown.

5. Continuous self-test features provide assurance that the FMCRD run-in logic is capable of functioning as designed. No single logic failure can result in the failure of more than one rod to insert.

The above features contribute to the high reliability of the ATWS FMCRD run-in feature of the ABWR design. Classification of the motors as safety-related (Class 1E) is not warranted, either by current regulatory requirements or from a reliability standpoint.

5.2.2

and reclosure in the safety mode occur at a higher pressure than the respective "normal" opening and reclosure in the relief mode (i.e., as normally initiated by pressure sensors in the steam lines).

The upper reclosure limit (reclosure point at 96% of opening setpoint) is a reasonable upper limit which will serve to limit the number of times the SRV will open and reclose in case of a pressure transient causing valve operation in the safety mode. It permits the valve to remain open longer and cycle less often (as compared with prior allowed upper reclosure limits, which were set at 97% and 98% of opening setpoint in the past).

The 96% upper limit also provides an extra measure of insurance that deviations in manufacturing tolerances, actual back-pressure in service, and other such variables do not result in an SRV with negative blowdown, in which buildup of backpressure would reclose the valve before it could perform its pressure relief function.

QUESTION 440.22

In Figure 5.1.3a the SRV solenoid valves are not shown as DC powered as they should be. Note 8 states that "valve motor operators and pilot solenoids are ac operated unless otherwise specified."

RESPONSE 440.22

At the next revision, Figure 5.1.3a will be revised to show that the SRV solenoids are DC powered.

QUESTION/RESPONSE 440.23

This question number not used.

QUESTION 440.24

Confirm that SRVs are designed to meet seismic and quality standards consistent with the recommendations of Regulatory Guides 1.26 and 1.29.

RESPONSE 440.24 The SRVs are classified as Quality Group A and seismic Category I as shown in Table 3.2-1. The SRVs are designed to meet Regulatory Guides 1.26 and 1.29.

(1) Tests required by ASME Code Section III for Class I valves are imposed in the ABWR SRV equipment specification. Analyses equivalent to those required by ASME III are performed in accordance with the requirements of MITI-501 (the Japanese equivalent of ASMEIII).

(2) SRV's are Class IE (active, safety related, electrically driven). It is currently planned to impose a complete environmental qualification program on the entire SRV, including both electrically and pneumatically driven components of the actuator system. This program includes dynamic qualification of operability following the Japanese equivalent of an SSE. This program will be in compliance with NUREG-0588 requirements.

QUESTIONS/RESPONSES 440.25 through 440.27

These questions numbers not used.

QUESTION 440.28

In SSAR Table 1.8-19, it is stated that branch technical position RSB 5-2 is applicable for ABWR. How does the ABWR design comply with BTP RSB 5-2?

so that they are sensitive to air temperature only and not radiated heat from hot piping or equipment. Increases in ambient temperature will indicate leakage of reactor coolant into the area. These monitors have sensitivities suitable for detection of reactor coolant leakage into the monitored areas of 25 gpm or less (8.35 pounds of steam is equivalent to 1 gallon of condensate). The temperature trip setpoint will be a function of the room size and the type of ventilation provided. These monitors provide alarm and indication and recording in the control room and will trip one isolation logic to close selected isolation valves, e.g., the main steam tunnel monitors will close the main steamline and MSL drain isolation valves and others, (Table 5.2-6).

Leakage detection will be provided in the turbine building. The turbine building monitors will also alarm and indicate in the control room and trip the isolation logic to close the main steamline isolation valves and MSL drain isolation valves when leakage reaches 25 gpm.

Large leaks external to the drywell (e.g., process line breaks outside of the drywell) are detected by low reactor water level, high process line flow, high ambient temperatures in the piping or equipment areas, floor or equipment drain sump activity, high differential flow (RWCS only), low steamline pressures or low main condenser vacuum. These monitors provide alarm and indication in the control room and will trip the isolation logic to cause closure of appropriate system isolation valves on the indication of excess leakage (Table 5.2-6).

Intersystem leakage detection is accomplished by monitoring radiation of the reactor building cooling water (RBCW) coolant return lines from the reactor internal pumps (RIP), residual heat removal (RHR), and reactor water cleanup system (RWCS) and fuel pool cooling heat exchangers. This monitoring is provided by the process radiation monitoring system.

Listed below are the variables monitored for detection of leakage from piping and equipment located external to the primary containment (drywell):

(1) Within reactor building:

(a) Main steamline and RCIC steamline high flow

(b) Reactor vessel low water level

(c) High flow rate from reactor building sumps outside drywell

(d) High temperature in equipment areas of RCIC, RHR, and the hot portions of the RWCS

(e) RCIC turbine exhaust line high diaphragm pressure

(f) High differential flow rate in RWCS piping

(g) High radiation in the RHR, RWCS, and RIP (and FPC) reactor building cooling water heat exchanger discharge lines (intersystem leakage)

(h) RCIC steamline low pressure

(2) Within steam tunnel (between primary containment and turbine building):

(a) High radiation in main steamlines (steam tunnel)

(b) Main steam tunnel high ambient air temperature

~~(c) High flow rate from steam tunnel sumps~~

(3) Within turbine building (outside secondary containment):

(a) Main steamline low pressure

(b) Low main condenser vacuum

(c) Turbine building ambient temperature in areas traversed by main steam lines

5.2.5.2 Leak Detection Instrumentation and Monitoring

RWCS can be isolated first and thereby preserve the operation of the RCIC system for core cooling if the high ambient temperature is due to leaks in nonessential systems. The delay is long enough to permit the tunnel ventilation system to lower temperatures to below the RCIC isolation trip setpoint after the nonessential system leak has been isolated. A time delay is provided for RWCS differential flow isolation signals to prevent system isolation during RWCS surges.

The LD&IS is a four divisional system which is redundantly designed so that failure of any single element will not interfere with a required detection of leakage or a required isolation. In the four division portions of the LD&IS, applied where inadvertent isolation could impair plant performance (e.g., closure of the MSIVs), any single channel or divisional component malfunction will not cause a false indication of leakage and it will not cause a false isolation trip because it will only trip one of the four channels and two or more channels are required to trip in order to cause closure of the main steamline isolation valves. The LD&IS thus combines a very high probability of operating when needed with a very low probability of operating falsely. The system is testable during plant operation.

5.2.5.3 Indication in the Control Room

Leak detection methods are discussed in Subsection 5.2.5.1. Details of some of the LD&IS alarms, recordings and other indications in the control room are discussed in Subsections 5.2.5.1.1, 5.2.5.1.2, 5.2.5.2.1 and 5.2.5.2.2. Further details of the LD&IS control room indications are included in Subsections 7.3.1.1.2, 7.6.1.3 and 7.7.1.7.

5.2.5.4 Limits for Reactor Coolant Leakage

5.2.5.4.1 Total Leakage Rate

The total reactor coolant leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The total leakage rate limit is well within the makeup capability of the RCIC system (800 gpm). The total reactor coolant leakage rate limit is established at ~~30~~ 25 gpm. The identified and unidentified leakage rate limits are established at 25 gpm and ~~up to 5~~ 1 gpm, respectively.

The total leakage rate limit is established low enough to prevent overflow of the sumps. The equipment drain sumps and the floor drain sumps, which collect all leakage, are each pumped out by two 50 gpm pumps.

If either the total or unidentified leak rate limits are exceeded, an orderly shutdown can be initiated and the reactor can be placed in a cold shutdown condition within 24 hours.

5.2.5.4.2 Identified Leakage Inside Drywell

The valve stem packing of large power operated valves, the reactor vessel head flange seal and other seals in systems that are part of the reactor coolant pressure boundary, and from which normal design identified source leakage is expected, are provided with leakoff drains. The nuclear system valves inside the drywell and the reactor vessel head flange are equipped with double seals. The leakage rates from the inner valve stem packings and the reactor vessel head flange inner seal, which discharge to the drywell equipment drain sump, are measurable during plant operation. Leakage from the main steam SRVs, discharging to the suppression pool, is monitored by temperature sensors mounted in thermowells in the individual SRV exhaust lines. The thermowells are located several feet from the valve bodies so as to prevent false indication. These temperature sensors transmit signals to the control room and any temperature increase detected by these sensors, that is above the ambient temperatures, indicates SRV leakage.

5.2.5.5 Unidentified Leakage Inside the Drywell

5.2.5.5.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the drywell sumps that is not identified as previously described. A threat of significant compromise to the nuclear system process barrier exists if the barrier contains a crack that is large enough to propagate rapidly (critical crack length). The unidentified leakage rate limit must be low because of the possibility that most of the from "Testing Procedures". As was indicated in Subsystem 5.2.5.7, the Position C8 requirements of RG 1.45 are satisfied, as, per the requirements, the leak detection systems of the ABWR are "equipped with provisions to readily permit testing for operability and calibration during plant operations." The SSAR text provides example testing methods to show how provisions had been made to permit testing for operability and calibration during plant operations.

In the context of this question, "Testing Procedures" are those viable methods which can be used during reactor operations to confirm the operability of specific leak detection systems, or are the methods which, because of design features or provisions, can be used to confirm that adequate calibration has been maintained, e.g., by the cross comparing or correlation of the signal outputs from two or more leak detection systems.

As an example of provisions in the design, the sump design for the ABWR requires that the sumps be configured such that the sump volume increases as a function of water level in the ratio of 16 gallons per vertical inch. The sump level monitoring is compatible with this sump configuration. By using sump pump timers, the rate at which a sump fills with reference to sump pump operations can determine the degree of abnormal leakage collected in the sump. Also, the rate of actual sump level change, which is also being monitored can determine the degree of abnormal leakage. Because of the required sump configuration, these two measures of the degree of abnormal leakage have a known correlation. As another example, the measurement of drywell air coolers condensate flow can be checked against sump level rate of change.

Similar examples of such "Testing Procedures" are methods as provided in Subsection 5.2.5.7 to show satisfaction or compliance with Position C8 requirements.

RESPONSE 430.3e

Part e of Question 430 apparently requests discussion related to compliance with RG 1.45 Position C8 with respect to the possible inclusion of new limiting conditions in the ABWR Technical Specifications for the leakage collected outside the drywell, i.e., unidentified and identified leakage collected in the reactor building and ~~other area (e.g., main steam tunnel area)~~ floor drain (HCW) sumps and equipment drain (LCW) sumps.

Such inclusion for the ABWR Technical Specifications is not being proposed. As indicated at the outset of this response, the statement in Subsection 5.2.5.4.1 has been revised.

5.4.6/9.2.9

the following suggested procedure:

(1) With the reactor at approximately 125°F and normal water level and decay heat being removed by the RHR system in the shutdown cooling mode, all main steam isolation valves are closed utilizing both spring force and air pressure on the operating cylinder.

(2) Nitrogen is introduced into the reactor vessel above normal water level and into the connecting main steamlines and pressure is raised to 20-30 psig. An alternate means of pressurizing the upstream side of the inside isolation valve is to utilize a steamline plug capable of accepting the 20 to 30 psig pressure acting in a direction opposite the hydrostatic pressure of the fully flooded reactor vessel.

(3) A pressure gage and flow meter are connected to the test tap between each set of main steam isolation valves. Pressure is held below 1 psig, and flow out of the space between each set of valves is measured to establish the leak rate of the inside isolation valve.

(4) To leak check the outer isolation valve, the reactor and connecting steamlines are flooded to a water level that gives a hydrostatic head at the inlet to the inner isolation valves slightly higher than the pneumatic test pressure to be applied between the valves. This assures essentially zero leakage through the inner valves. If necessary to achieve the desired water pressure at the inlet to the inner isolation valves, gas from a suitable pneumatic supply is introduced into the reactor vessel top head. Nitrogen pressure (20 to 30 psig) is then applied to the space between the isolation valves. The pistons are checked for leak tightness. Once any detectable piston ring leakage to the drain system has been accounted for, the seat leakage test is conducted by shutting off the pressurizing gas and observing any pressure decay. The volume between the closed valves is accurately known. Correction for temperature variation during the test period are made,if necessary, to obtain the required accuracy. Pressure and temperature are recorded over a long enough period to obtain meaningful data. An alternate means of leak testing the outer isolation valve is to utilize the previously noted steamline plug and to determine leakage by pressure decay or by inflow of the test medium to maintain the specific test pressure.

During pre-startup tests following an extensive shutdown, the valves will receive the same hydro tests that are imposed on the primary system.

Such a test and leakage measurement program ensures that the valves are operating correctly.

5.4.6 Reactor Core Isolation Cooling System

~~Evaluations of the reactor core isolation cooling system against the applicable General Design Criteria are provided in Subsection 3.1.2.~~ 440.45

INSERT C

5.4.6.1 Design Basis

The reactor core isolation cooling (RCIC) system is a safety system which consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to assure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to take place. This prevents reactor fuel overheating during the following conditions:

(1) a loss-of-coolant (LOCA) event;

(2) vessel isolated and maintained at hot standby;

(3) vessel isolated and accompanied by loss of coolant flow from the reactor feedwater system;

(4) complete plant shutdown with loss of normal feedwater before the reactor is depressurized to a level where the shutdown cooling system can be placed in operation; or

(5) loss of AC power for 30 minutes.

Acceptence criteria II.3 of SRP Section 5.4.6 states that the RCIC system must perform its function without the availability of any a-c power. Review Procedure III.7 further requires

C

Evaluations of the reactor core isolation cooling system against the General Design Criteria (GDC) 5, 29, 33, 34 and 54 are provided in Subsection 3.1.2. Evaluations against the ECCS GDC 2, 17, 27, 35, 36 and 37 are provided below.

Compliance with GDC 2. The RCIC system is housed within the reactor building which provides protection against wind, floods, missiles and other natural phenomena. Also, RCIC system and its components are designed to withstand earthquake and remain functional following a seismic event.

Compliance with GDC 17. The RCIC is a part of the ECCS network. It is powered from a Class 1E source independent of the HPCF power sources. Although RCIC is a single loop system, it is redundant to the two HPCF loops which comprise the high pressure ECCS (1-RCIC and 2-HPCF). Since independent Class 1E power supplies are provided, redundancy and single failure criteria are met, GDC 17 is satisfied.

Compliance with GDC 27. As discussed in Subsection 3.1.2.3.8.2, the design of the reactivity control systems assures reliable control of reactivity under postulated accident conditions with appropriate margin for stuck rods. The capability to cool the core is maintained under all postulated accident conditions by the RHR system. Thus, GDC 27 is satisfied without RCIC system.

Compliance with GDC 35. The RCIC in conjunction with HPCF, RHR and auto depressurization systems perform adequate core cooling to prevent excessive fuel clad temperature during LOCA event. Detailed discussion of RCIC meeting this GDC is described in Subsection 3.1.2.

Compliance with GDC 36. The RCIC system is designed such that in-service inspection of the system and its components is carried out in accordance with the intent of ASME Section XI. The RCIC design specification requires layout and arrangement of containment penetrations, process piping, valves, and other critical equipment outside the reactor vessel, to the maximum practical extent, permit access by personnel and/or appropriate equipment for testing and inspection of system integrity.

(C) (CONTINUED)

Compliance with GDC 37. The RCIC system is designed such that system and its components can be periodically tested to verify operability. Systems operability is demonstrated by preoperational and periodic testings in accordance with RG 1.68. Preoperational test will ensure proper functioning of controls, instrumentation, pumps and valves. Periodic testings confirm systems availability and operability through out the life of the plant. During normal plant operation, a full flow pump test is being performed periodically to assure systems design flow and head requirements are attained. All RCIC system components are capable of individual functional testings during plant operation. This includes sensors, instrumentation, control logics, pump, valves, and more. Should the need for RCIC operation occur while the system is being tested, the RCIC system and its components will automatically re-aligned to provide cooling water into the reactor. The above test requirements satisfy GDC 37.

(6) General

Periodic inspections and maintenance of the turbine-pump unit are conducted in accordance with manufacturers instructions. Valve p ition indication and instrumentation alarms are displayed in the control room.

5.4.6.2.5 System Operation

Manual actions required for the various modes of RCIC are defined in the following subsections.

5.4.6.2.5.1 Standby Mode

During normal plant operation, the RCIC system is in a standby condition with the motor-operated valves in their normally open or normally closed positions as shown in the piping and instrumentation diagram (P&ID) included in Figure 5.4-8. In this mode, the RCIC pump discharge line is kept filled. The relief valve in the pump suction line protects against overpressure from backleakage through the pump discharge isolation valve and check valve.

5.4.6.2.5.2 Emergency Mode (Transient Events and LOCA Events)

Startup of the RCIC system occurs automatically either upon receipt of a reactor vessel low water level signal (Level 2) or a high drywell pressure signal. During startup, the turbine control system limits the turbine-pump speed to its maximum normal operating value, controls transient acceleration, and positions the turbine governor valve as required to maintain constant pump discharge flow over the pressure range of the system. Input to the turbine governor is from the flow controller monitoring the pump discharge flow. During standby conditions, the flow controller output is saturated at its maximum value.

When the RCIC system is shut down, the low signal select feature of the turbine control system selects the idle setting of a speed ramp generator. The ramp generator output signal during shutdown corresponds to the low limit step and a turbine speed demand of 700 to 1000 rpm.

On RCIC system start, the bypass valve F092 (provided to reduce the frequency of turbine overspeed trips) opens to accelerate the turbine to an initial peak speed of approximately 1500 rpm; now under governor control, turbine speed is returned to the low limit turbine speed demand of 700 to 1000 rpm. After a predetermined delay (5 to 10 sec), the steam supply valve leaves the full closed position and the ramp generator is released. The low signal select feature selects and sends this increasing ramp signal to the governor. The turbine increases in speed until the pump flow satisfies the controller setpoint. Then the controller leaves saturation, responds to the input error, and integrates the output signal to satisfy the input demand.

The operator has the capability to select manual control of the governor, and adjust speed and flow (within hardware limitations) to match decay heat steam generation during the period of RCIC operation.

The RCIC pump delivers the makeup water to the reactor vessel through the feedwater line, which distributes it to obtain mixing with the hot water or steam within the reactor vessel.

The RCIC turbine will trip automatically upon receipt of any signal indicating turbine overspeed, low pump suction pressure, high turbine exhaust pressure, or an auto-isolation signal. Automatic isolation occurs upon receipt of any signal indicating:

(1) A high pressure drop across a flow device in the steam supply line equivalent to 300% of the steady-state steam flow at 1192 psia.

(2) A high area temperature.

(3) A low reactor pressure of 50 psig minimum.

(4) A high pressure between the turbine exhaust rupture diaphragms.

The steam supply, steam supply bypass and cooling water supply valves will close upon receipt of signal indicating high water level (Level 8) in the reactor vessel. These valves will reopen should an indication of low water level (Level 2) in the reactor vessel occur. The RCIC system can also be started, operated, and shut down remote-manually provided initiation or shutdown signals do not exist.

9.2 WATER SYSTEMS

9.2.1 Station Service Water System

The functions normally performed by the station service water system are performed by the systems discussed in Subsection 9.2.11.

9.2.2 Closed Cooling Water System

The functions normally performed by the closed cooling water system are performed by the systems discussed in Subsections 9.2.11, 9.2.12, 9.2.13, and 9.2.14.

9.2.3 Demineralized Water Makeup System

The functions normally performed by the demineralized water makeup system are performed by the systems discussed in Subsections 9.2.8, 9.2.9 and 9.2.10.

9.2.4 Potable and Sanitary Water Systems

Out of ABWR Standard Plant Scope.

9.2.5 Ultimate Heat Sink

Out of ABWR Standard Plant scope. See Subsection 9.2.15.1 for interface requirements.

9.2.6 Condensate Storage Facilities and Distribution System

The functions of the storing and distribution of condensate are described in Subsection 9.2.9.

9.2.7 Plant Chilled Water Systems

The functions of the plant chilled water system are performed by the systems described in Subsections 9.2.12 and 9.2.13.

9.2.8 Makeup Water System (Preparation)

Out of ABWR Standard Plant scope. See Subsection 9.2.15.2 for interface requirements.

9.2.9 Makeup Water System (Condensate)

9.2.9.1 Design Bases

(1) The makeup water-condensate system (MUWC) shall provide condensate quality water for both normal and emergency operations when required.

(2) The MUWC system shall provide a required water quality as follows:

Conductivity (μ S/cm) $\leq$ 0.5 at 25°C
Chlorides, as Cl (ppm) $\leq$ 0.02
pH 5.9 to 8.3 at 25°C
Conductivity and pH limits shall be applied after correction for dissolved CO_2. (The above limits shall be met at least 90% of the time.)

(3) The MUWC system shall supply water for the uses shown in Table 9.2-1.

(4) The MUWC system is not safety related.

(5) The condensate storage tank shall have a capacity of 2,110 m^3. This capacity was determined by the capacity required by the uses shown in Table 9.2-2.

(6) All tanks, piping and other equipment shall be made of corrosion-resistant materials.

INSERT D

9.2.9.2 System Description

The MUWC P&ID is shown in Figure 9.2-4 This system includes the following: 410.44

(1) A condensate storage tank (CST) is provided. It is of concrete construction with a stainless steel lining. The volume is shown in Table 9.2-3.

(2) The following pumps take suction from the CST:

(a) RCIC pumps

(b) CRD pumps

(c) HPCF pumps

(d) SPCU pumps

D

(7) The HPCF and RCIC instrumentation, which initiates the automatic switchover of HPCF and RCIC suction from the CST header to the suppression pool, shall be designed to safety-grade requirements (including installation with necessary seismic support).

rerouted to the vessel should system initiation be required during CST to CST testing. There would also be additional interlocks needed to prevent pumping suppressing pool water to the CST. Complexity and cost would also increase from the required maintenance of the additional hardware, instrumentation and logic.

Suppression pool water quality will be maintained by the suppression pool cleanup system which is designed to be operated continuously. Although this quality may be somewhat less than that of the CST, it will be consistent with infrequent filling of RCIC piping during testing and possible injection to the RPV and therefore the reference draining, flushing and filling of the system is not necessarily required. Additionally, an decrease in personnel exposure realized by performing CST to CST testing (assuming draining, flushing and filling were required) might be fully or partially offset by an increase from the additional maintenance considerations.

QUESTION 440.42

Why are the power supply for valves F063, F064, F076, F077, and F078 standby AC instead of DC?

RESPONSE 440.42

For the ABWR RCIC, only the steam supply inboard isolation valves, F063 and F076 are powered from AC source. F064 and all other MOV's are DC powered. Figure 5.4-8 will be updated at its next revision to indicate the correct power supply.

Valves F077 and F078 have recently been removed from the ABWR RCIC design. The line where these valves were located performed a vacuum breaking function of the turbine exhaust line and had a separate containment penetration. The current ABWR RCIC configuration eliminated F077 and F078 since the vacuum breaking function is now inside containment and has no separate penetration that mandates provision for F077 and F078. Figure 5.4-8 will be updated at its next revision to reflect the deletion this line of these valves.

The use of AC power source for F063 and F076 is considered technically acceptable for the following reasons:

(1) DC motors require considerably more maintenance than AC motors. Since they cannot be maintained during plant operating if they are located inside the drywell, DC MOV's would be far less reliable than AC.

(2) During loss of AC power RCIC system will remain operable since these valves are normally open.

QUESTION 440.43

Address the following TMI-2 action Items related to RCIC.

(a) II.K.1.22

(b) II.K.3.13

(c) II.K.3.15

(d) II.K.3.22

(e) II.K.3.24

RESPONSE 440.43

Response to this question is provided in Appendix 1A.

QUESTION 440.44

Confirm that the RCIC system meets the guidelines of Regulatory Guide 1.1 regarding pump Net Positive Suction Head (NPSH).

RESPONSE 440.44

The key requirement of Regulatory Guide 1.1 is that no credit be taken for containment pressurization when establishing the NPSH conditions for ECCS pumps. The RCIC meets this requirement. New Table 5.4-1a provides the numerical evaluation of RCIC NPSH conditions assuming no containment pressurization and 77°C (170°F) suppression pool water temperature In summary, the RCIC pump will have over 2.5 feet NPSH margin at the most limiting condition.

Note that NPSH calculation is based on suppression pool temperature of 77°C. This is the maximum temperature RCIC is expected to operate.

The following summarizes the transient/accident events which can result in increasing suppression pool water temperature. It summarizes the basis for concluding that RCIC NPSH conditions (14.7 psia containment pressure, 77°C suppression pool water) are acceptable.

EVENT	RCIC NPSH ASSESSMENT *
Reactor Isolation Event	Maximum pool temperature well below 77°C (approx. 49°C)
Large Break LOCA	Rapid vessel depressurization. RCIC not required.
Intermediate Size LOCA	Rapid vessel depressurization. Reactor pressure less than 150 psig before pool temperature reaches 77°C.
Small Break LOCA	RCIC operation not required when pool temperature reaches 77°C.
Station Black Out Event (8 hours capability)	RCIC suction is taken from the condensate storage tank (CST) with a capacity of 8 hour operation. Suppression pool (S/P) water is not expected to be used during this event. However, if the automatic transfer of suction from the CST to S/P were to occur due to high S/P water level, a manually controlled override switch is operated to continue taking suction from the condensate storage tank.

*RCIC design basis requires 100 percent system flow only for reactor pressure > 150 psig.

QUESTION 440.45

SRP 5.4.6 identifies GDCs 5, 29, 33, 34 and 54 in the acceptance criteria. Confirm that the RCIC system, described in Chapter 5.4.6 of the SSAR, meets the requirements of the above GDCs.

TABLE 5.4-1a

NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE TO RCIC PUMPS

A. Suppression pool is at its minimum depth, El. -3740mm (-12.27 Ft).

B. Centerline of pump suction is at El. -7200mm (-23.62 Ft).

C. Suppression pool water is at its maximum temperatue for the given operating mode, 77°C (170°F).

D. Pressure is atmospheric above the suppression pool.

E. Maximum suction strainer losses are 2.0 psi. (50% plugged)

NPSH = H_{ATM} + H_S -H_{VAP} -H_F

where:

H_{ATM} = atmospheric head

H_S = static head

H_{VAP} = vapor pressure head

H_F = Frictional head including strainer

<u>Minimum Expected NPSH</u>

Maximum suppression pool temperature is 77°C (170°F)

H_{ATM} = 10.73m (35.20 Ft)

H_S = 3.46m (11.35 Ft)

H_{VAP} = ~~3.46m (11.35 Ft)~~ 4.22 m (13.85 Ft)

H_F = 1.82m (5.97 Ft)

Strainer head loss = 2.0 psi = 1.46m = 4.80 Ft

NPSH available = 10.73 + 3.46 - ~~9.74~~ 4.22 - 1.82 = ~~2.63m (8.63 Ft)~~ 8.15 m (26.73 Ft)

NPSH required = 7.3m ~~(23.95 Ft)~~ (24 Ft)

* NPSH Reference Point

440.44

testing done by Terry Co. with water applicable to the ABWR? Describe in detail the components, especially the turbine and the pump.

RESPONSE 440.48

The ABWR RCIC equipment specification does not specify the type of turbine, rather, its performance requirements. Performance testing will be performed with water applicable to the ABWR Standard Plant design. The equipment and component description given in Subsection 5.4.6.2.2 is commensurate with a standard design. The depth of information provided in this subsection is the same as that provided for BE's standard BWR/6 Nuclear Island design. This information is reflected in the RCIC equipment specification. The amount of information provided is sufficient to delineate the performance requirements of the RCIC without restricting its supply by qualified equipment vendors.

QUESTION 440.49

To the best of our knowledge, the steam isolation valves F063 and F064 in currently operating BWRs are not tested with a steam pipe break downstream and with actual operating conditions (pressure 1000 psig and temperature 546 degrees F). There is no guarantee that the steam isolation valves will close during a break. We require that a proper testing of the valves be performed before the final design approval. (Reference Generic Issue GI-87 "Failure of HPCI Steam Line Without Isolation.")

RESPONSE 440.49

The ABWR RCIC equipment specification requires that the valves in question close within a specified time under prescribed environmental conditions. The method of confirmation will be either testing or demonstration of similarity with previously qualified valves. Since this is a standardized design it is not possible to identify a specific equipment vendor and the method of confirmation. However, the commitment to either test or demonstrate via similarity has been considered sufficient in past NRC reviews of standardized designs.

QUESTION 440.50

Steam isolation valves F063 and F064 are to be opened in sequence to reduce water hammer and for slow warm-up of the piping. F064 and F076 are opened first. The valves logic should prevent the operator from opening the valves out of sequence. Confirm that the valves control logic includes an interlock.

RESPONSE 440.50

~~GE does not consider that an interlock is necessary since opening of these valves is governed by strict administrative and procedural control.~~

~~The ABWR design specification requires these valves to be opened sequentially as stated below:~~

~~"In order to prevent damage from water hammer, neither steam isolation valve is opened automatically by an initiation signal. Should either or both of these valves be closed, they must be reopened by firsts closing both valves completely. With both valves closed, the outboard isolation valve F064 can be reopened to allow any moisture in the line to drain. Then moisture ahead of the inboard isolation valve F063 is drained slowly as line pressure across inboard isolation valve is equalized and the downstream line is warmed by slowly opening the inboard isolation valve bypass valve F076. Finally, the inboard isolation valve F063 may be reopened."~~

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(E)

The inboard (F063) and outboard (F064) isolation valves are provided with keylock switches as protective features in addition to several administrative constraints. Administratively, the valve control switch key must be obtained, then (1) the key must be inserted into the lock to enable the maintained contact switch and (2) the switch must be turned from **OPEN** to **CLOSE** to enable reset of the sealed-in isolation signal from the leak detection system. (An interlock for the isolation valve to be in **CLOSE** position before the leak detection system isolation signal can be reset is in compliance with NUREG 0737. NUREG 0737 Item II.E.4.2 Position 4 requires that isolation valves must not open automatically upon reset of the isolation signal and must only be opened by a deliberate operator action).

Upon reset of the leak detection system, the outboard isolation valve (F064) is allowed to open by placing the control switch key in the **OPEN** or **STOP** (intermediate position for throttling) position to drain trapped condensate between the inboard and the outboard isolation valves. Then the inboard bypass valve (F076) is opened to drain trapped condensate upstream of the inboard isolation valve (F063) at the same time slowly equalizing the pressure across inboard valve (F063) and warming-up the downstream piping. Finally, the inboard isolation valve (F063) is opened by placing the control switch key in the **OPEN** position to allow full pressurization of the steam line. This opening sequence procedure is delineated in the RCIC system design specification and RCIC system operating procedure.

GE considers that an interlock between the inboard and outboard valves is not necessary. The addition of an interlock will only complicate the logic without an offsetting benefit. Even if an interlock is provided, the potential for water hammer is still likely to exist if the operator failed to drain, equalize and warm-up the line before opening the inboard valve.

Another complication to an interlock is that the outboard valve (F064) is a throttling type. Once the inboard valve is opened, the interlock prevents inching of the outboard valve (F064).

It is GE's position that strict administrative and procedural control is adequate. The same administrative and procedural control is being practiced on all GE BWR's and to date no such problem has been reported.

testing done by Terry Co. with water applicable to the ABWR? Describe in detail the components, especially the turbine and the pump.

RESPONSE 440.48

The ABWR RCIC equipment specification does not specify the type of turbine, rather, its performance requirements. Performance testing will be performed with water applicable to the ABWR Standard Plant design. The equipment and component description given in Subsection 5.4.6.2.2 is commensurate with a standard design. The depth of information provided in this subsection is the same as that provided for BE's standard BWR/6 Nuclear Island design. This information is reflected in the RCIC equipment specification. The amount of information provided is sufficient to delineate the performance requirements of the RCIC without restricting its supply by qualified equipment vendors.

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RESPONSE 440.49

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The ABWR RCIC equipment specification requires that the valves inquestion close within a specified time under actual operating conditions. Since this is a standardized design it is not possible to identify a specific equipment vendor and test the valve before the final design approval. However, GE will closely follow the current valve testing in support of GI-87 and will make appropriate modifications to the equipment specification prior of issuance of the final SER.

5.4.7

system may be performed during normal plant operation by drawing suction from the suppression pool and discharging through a full flow test return line back to the suppression pool. The discharge valve to the vessel remains closed during test mode operation. The system will automatically return from test to operating mode if system initiation is required and the flow will be automatically directed to the vessel.

5.4.6.2.5.4 Limiting Single Failure

The most limiting single failure with the RCIC system and its HPCF system backup is the failure of HPCF. With an HPCF failure, if the capacity of RCIC system is adequate to maintain reactor water level, the operator shall follow Subsection 5.4.6.2.5.2: However, if the RCIC capacity is inadequate, Subsection 5.4.6.2.5.2 still applies, but additionally the operator may also initiate the ADS system described in Subsection 6.3.2.2.2.

5.4.6.3 Performance Evaluation

The analytical methods and assumptions in evaluating the RCIC System are presented in Chapter 15 and Appendix 15A. The RCIC system provides the flows required from the analysis (Figure 5.4-9) within a 30 second interval based upon considerations noted in Subsection 5.4.6.2.4.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14.

5.4.7 Residual Heat Removal System

440.62 Evaluations of residual heat removal (RHR) system against the applicable General Design Criteria (GDC) are provided in Subsection 3.1.2 and 5.4.7.1.4.

5.4.7.1 Design Basis

The RHR is composed of three electrically and mechanical independent divisions designated A, B, and C. Each division contains the necessary piping, pumps, valves and heat exchangers. In the low pressure flooder mode, suction is taken from the suppression pool and injected into the vessel outside the core shroud (via the feedwater line on Division A and via the core cooling subsystem discharge return line on Divisions B and C).

The RHR provides two independent containment spray cooling systems (on loops B and C) each having a common header in the wetwell and a common spray header in the drywell and sufficient capacity for containment depressurization.

Shutdown cooling suction is taken directly from the reactor via three shutdown cooling suction nozzles on the vessel. Shutdown cooling return flow is via the feedwater lines on loop A and via core cooling subsystem discharge return lines on loops B and C.

Connections are provided to the upper pools on two loops to return shutdown cooling flow to the upper pools during normal refueling activities if necessary. These connections also allow the RHR to provide additional fuel pool cooling capacity as required by the fuel pool cooling system during the initial stages of the refueling outage.

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5.4.7.1.1 Functional Design Basis

The RHR provides the following four principal functions:

(1) Core cooling water supply to the reactor to compensate for water loss beyond the normal control range from any cause up to and including the design basis (LOCA).

(2) Suppression pool cooling to remove heat released to the suppression pool (wetwell), as necessary, following heat inputs to the pool.

(3) Wetwell and drywell sprays to remove heat and condense steam in both the drywell and wetwell air volumes following a LOCA. In addition, the drywell sprays are intended to provide removal of fission products released during a LOCA.

(4) Shutdown cooling to remove decay and sensible heat from the reactor. This includes the safety-related requirements that the reactor must be brought to a cold

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As shown in Table 5.4-4, the RHR heat exchanger primary (tube) side design pressure is 500 psig and the secondary (shell) side design pressure is 200 psig. This pressure distribution is acceptable for the following reasons:

(1) Heat exchanger primary side leakage is accomodated by the surge tank of the pump loop of the reactor building cooling water system. The inlet to the secondary side of the heat exchanger is always open to this continously running pump loop.

(2) The ABWR design bases against interfacing LOCAs essentially eliminates interfacing LOCA concerns by requiring that : (a) two or more malfunctions are necessary to expose piping systems to reactor operating pressure with design pressures greater than or equal to one-third reactor operating pressure (e.g., RHR heat exchanger primary side);and (b) three or more malfunctions are necessary to expose piping systems to reactor operating pressure with design pressures less than one-third reactor operating pressure (e.g., RHR heat exchanger secondary side).

Further, the interfacing LOCAs design bases requires the motor operated ECCS injection valves to be tested with the reactor vessel at low pressure and ECCS injection lines to have inboard testable check valves with position indication in the control room.

Table 5.4-4

RHR HEAT EXCHANGER DESIGN AND PERFORMANCE DATA

Number of units	3
Seismic	Category I design and analysis
Types of exchangers	Horizontal U-Tube/Shell
Maximum primary/secondary side pressure	500 psig / 200 psig
Design Point Function Cooling	Post-LOCA Containment
Primary side (tube side) performance data	
(1) Flow	4200 gpm
(2) Inlet temperature	358° maximum
(3) Allowable pressure drop (max)	10 psi
(4) Type water	Suppression Pool or Reactor Water
(5) Fouling factor	0.0005
Secondary side (shell side) performance data	
(1) Flow	5,280 gpm
(2) Inlet temperature	105°F maximum
(3) Allowable pressure drop - maximum	10 psi
(4) Type water Water	Reactor Building Cooling
(5) Fouling factor	0.0005

The relief valves for the RHR system (E11) are listed in Table 5.4-5 and the operating characteristics of each valve (i.e., their relieving pressure) are tabulated. All of the E11 relief valves in Table 5.4-5 are quality group B, safety class 2, and Seismic Category I. All valves are classified as an essential component whose prime safety function is active. All of the relief valves in Table 5.4-5 are standard configurations meeting all applicable codes and standards. None of these valves are air operated nor can their setpoint be changed by the operators.

5.4.7.2.3.1 Interlocks

(1) The valves requiring a keylock switch are F001, F032 and F033 as indicated on the RHR P&ID, Figure 5.4-10.

(2) It is not possible to open the shut down connection to the vessel in any given loop whenever the pool suction, pool discharge valve or containment spray valves are open in the same loop to prevent draining the vessel to the pool.

(3) Redundant interlocks prevent opening the shutdown connections to and from the vessel whenever the pressure is above the shutdown range. Increasing pressure trip shall cause closure of these valves.

(4) A timer is provided in each pump minimum flow valve control circuitry so that the pump has an opportunity to attain rated speed and flow before automatic control of the valve is activated. This time delay is necessary to prevent a reactor water dump to the suppression pool during the shutdown operation.

(5) It is not possible to operate the RHR main pumps without an open suction source because these pumps are used for core, vessel and containment cooling and their integrity must be preserved.

(6) Redundant interlocks prevent opening and automatically closes the shutdown suction connections to the vessel in any given loop whenever a low reactor level signal is present.

(7) In the absence of a valid LOCA signal without high drywell pressure and without the injection valve being fully closed, it is not possible to open the drywell spray valves in a loop when the corresponding containment isolation valve in the same loop is open; i.e., the two valves, in series, are both not to be open during shutdown or surveillance testing.

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5.4.7.2.4 Applicable Codes and Classifications

(1) Piping, Pumps, and Valves

(a) Process side ASME III Class 1/2
(b) Service water side
ASME III Class 3

(2) Heat Exchangers

(a) Process side ASME III Class 2
TEMA Class C

(b) Service water
side ASME III Class 3
TEMA Class C

(3) Electrical Portions

(a) IEEE 279

(b) IEEE 308

5.4.7.2.5 Reliability Considerations

The RHR system has included the redundancy requirements of Subsection 5.4.7.1.5. Three completely redundant loops have been provided to remove residual heat, each powered from a separate emergency bus. All mechanical and electrical components are separate. Two out of three are capable of shutting down the reactor within a reasonable length of time.

5.4.7.2.6 Manual Action

(1) Emergency Mode [Low pressure flooder (LPFL) mode]

H

5.4.7.2.3.2 Heat Exchanger Leak Leak Detection

A radiation detector is provided in the main loop of the reactor building cooling water (RCW) system, which cools the secondary side of the RHR heat exchanger. If radioactive water from the primary side of the heat exchanger leaks to the secondary side, the radiation detector will signal a radiation increase soon after the RHR is started. Conformation is achieved through a sample port in thc specific RHR pipe line of the RCW system.

(5) Systems that are normally filled with water and operating under post-LOCA conditions need not be vented.

(6) LLRT results shall be added to the ILRT results.

6.2.6.2 Containment Penetration Leakage Rate Test (Type B)

6.2.6.2.1 General

Containment penetrations whose designs incorporate resilient seals, bellows, gaskets, or sealant compounds, airlocks and lock door seals, equipment and access hatch seals, and electrical canisters, and other such penetrations are leak tested during preoperational testing and at periodic intervals thereafter in conformance to Type B leakage rate tests defined in Appendix J of 10CFR50. The leak tests ensure the continuing structural and leak integrity of the penetrations.

To facilitate local leak testing, a permanently installed system may be provided, consisting of a pressurized gas source (nitrogen or air) and the manifolding and valving necessary to subdivide the testable penetrations into groups of two to five. Each group is then pressurized, and if any leakage is detected (by pressure decay or flow meter), individual penetrations can be isolated and tested until the source and nature of the leak is determined. All Type B tests are performed at containment peak accident pressure, Pa. The local leak detection tests of Type B and Type C (Subsection 6.2.6.3) must be completed prior to the preoperational or periodic Type A tests.

6.2.6.2.2 Acceptance Criteria

The combined leakage rate of all components subject to Type B and Type C tests shall not exceed 60% of L_a (cfm). If repairs are required to meet this limit, the results shall be reported in a separate summary to the NRC. The summary shall include the structural conditions of the components which contributed to failure.

6.2.6.2.3 Retest Frequency

In compliance with the requirement of Section III.D.2(a) of Appendix J to 10CFR Part 50, type B tests (except for air locks) are performed during each reactor shutdown for major fuel reloading, or other convenient intervals, but in no case at intervals greater than two years.* Air locks opened when containment integrity is required will be tested in manual mode within 3 days of being opened. If the air lock is to be opened more frequently than once every 3 days, the air lock will be tested at least once every 3 days during the period of frequent openings. Air locks will be tested at initial fuel loading, and at least once every 6 months thereafter. Testing may be initiated automatically at the end of each interval by the seal test instrumentation system, with manual override of the automated sequence provided for in the associated logic. Testing involves the injection of air under pressure (15 psig) into the space between the two redundant seals in each door of the air lock. The leakdown rate is measured by sensing the pressure drop and/or flow rate necessary to maintain the pressure. Main control room readout of time to next test, test completion and test results is provided. An alarm sounds if the specified interval passes without a test being effected. No direct, safety-related function is served by the seal test instrumentation system. 130.49a & b

6.2.6.2.4 Design Provisions for Periodic Pressurization

In order to assure the capability of the containment to withstand the application of peak accident pressure at any time during plant life for the purpose of performing ILRTs, close attention is given to certain design and maintenance provisions. Specifically, the effects of corrosion on the structural integrity of the containment are compensated for by the inclusion of a 60-yr service life corrosion allowance, where applicable. Other design features that have the potential to deteriorate with age, such as flexible seals, are carefully inspected and tested as outlined in Subsection 6.2.6.2.2. In this manner, the structural and leakage integrity of the containment remains essentially the same as originally accepted.

In compliance with the requirement of Section III.D.2(b)(iii) of Appendix J to 10CFR Part 50

(6) vessel pressure as a function of time;

(7) flows out of the vessel as a function of time;

(8) flows into the vessel as a function of time;

(9) peak cladding temperature as a function of time.

A conservative licensing assumption is that all offsite AC power is lost simultaneously with the initiation of the LOCA. As a further conservatism, all reactor internal pumps are tripped at the start of LOCA event even though this in itself is considered to be an accident (See Subsection 15.3.1). The resulting rapid core flow coastdown produces a calculated departure from nucleate boiling in the hot bundles within the first few seconds of the transient.

LOCA analyses using break areas less than the maximum values were also considered for the steamline, feedwater line, and RHR shutdown suction line locations. The cases analyzed are indicated on the break spectrum plot (refer to Figure 6.3-10). In general, the largest break at each location is the worst in terms of minimum transient water level in the downcomer.

6.3.3.7.5 Intermediate Line Breaks Inside Containment

For these cases the maximum RHR/LPFL injection line break (0.221 ft^2) was analyzed. Important variables from this analyses are shown in Figures 6.3-37 through 6.3-43.

6.3.3.7.6 Small Line Breaks Inside Containment

For these cases the maximum high pressure core flooder line break (0.099 ft^2) and the maximum bottom head drain line break (0.0218 ft^2) were analyzed. Important variables from these analyses are shown in Figure 6.3-44 through 6.3-59. I INSERT The drainline break analysis is also bounding for any credible break within the reactor internal pump recirculation system and its associated motor ~~bounding~~ housing and cover.

As expected, the core flooder line break is the worst break location in terms of minimum transient water level in the downcomer. In elevation it is the lowest break on the vessel except for the drainline break. Furthermore, the worst break/failure combination leaves the fewest number of ECC systems remaining and no high pressure core flooder systems. LOCA analyses using break areas less than the maximum values were also considered. The cases analyzed are indicated on the break spectrum plot (refer to Figure 6.3-10). From these results it is clear that the overall most limiting break in terms of minimum transient water level in the downcomer, is the maximum core flooder line break case.

6.3.3.7.7 Line Breaks Outside Containment

This group of breaks is characterized by a rapid isolation of the break. Since a maximum steam line break outside the containment produces more vessel inventory loss before isolation than other breaks in this category, the results of this case are bounding for all breaks in this group. Important variables from these analyses are shown in Figure 6.3-60 through 6.3-66.

As discussed in Subsection 6.3.3.7.4, the trip of all reactor internal pumps at the start of the LOCA produces a calculated departure from nucleate boiling for all LOCA events. Furthermore, the high void content in the bundles following a large steamline break produces the earliest times of loss of nucleate boiling for any LOCA event. Thus, the summary of results in Table 6.3-4 show that, though the PCTs for all break locations are similar, the steamline breaks result in higher calculated PCTs and the outside steamline break is the overall most limiting case in terms of the highest calculated PCT.

6.3.3.7.8 Bounding Peak Cladding Temperature Calculation

Consistent with the SAFER application methodology in Reference 2, the Appendix K peak cladding temperatures calculated in the previous sections must be compared to a statistically calculated 95% probability value. Table 6.3-6 presents the significant plant variables which were considered in the determination of the 95% probability PCT. Again, since the ABWR LOCA results have a large margin to the acceptance

(I)

A break in a reactor internal pump would involve either the welds or the casing. If the weld from the pump casing to the PRV stub tube breaks, the stretch tube will prevent the pump casing from moving. The stretch tube clamps the diffuser to the stub tube and runs from the diffuser to a land in the pump casing, where its nut seats. The land is located below the casing attachment weld and therefore the stretch tube forms a redundant parallel strength path to the pump casing restraint which is designed to provide support in the event of weld failure. In case the pump casing and the stretch tube break, the pump and motor will move downward until stopped by the casing restraints. The pump will drop until the impeller seats on the backseat that is part of the stretch tube. In either case the break flow would be much less than the drainline break case. Therefore, plant variables in the conservative direction simultaneously. The results of this calculation for the limiting case are given in Figure 6.3-67 through 6.3-75 and Table 6.3-4. Since the ABWR results have large margins to the 10CFR50.46 licensing acceptance criteria, the ABWR licensing PCT can be based on the bounding PCT which is well below the 2200°F PCT limit.

6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of Section 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10CFR50.46 acceptance criteria, given operation at or below the MAPLHGRs in Table 6.3-7.

6.3.4 Tests and Inspections

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for their operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, setpoint, limit switch setting, torque switch setting, etc. Each pump is tested for flow capacity for comparison with vendor data. (This test is also used to verify flow measuring capability). The flow tests involve the same suction and discharge source (i.e., suppression pool).

All logic elements are tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

Finally, the entire system is tested for response time and flow capacity taking suction from its normal source and delivering flow into the reactor vessel. This last series of tests is performed with power supplied from both offsite power and onsite emergency power.

See Chapter 14 for a thorough discussion of preoperational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (nonoperating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: (1) the desired system availability (average reliability); (2) the number of redundant functional system success paths; (3) the failure rates of the individual components in the system; and (4) the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered).

All of the active components of the HPCF System, ADS, RHR and RCIC Systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a test line back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation.

All of the active components of the ADS System, except the safety/relief valves and their associated solenoid valves, are designed so that they may be tested during normal plant operation. The SRVs and associated solenoid valves are all tested during plant initial power ascension per Appendix A, Paragraph D.2.c of Regulatory Guide 1.68. SRVs are bench tested to establish lift settings.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Subsection 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Subsection 8.3.1. The frequency of testing is specified in the Chapter 16 Technical Specifications. Visual inspections of all the ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access

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The bounding PCT is greater than the Appendix K value. This is typical of the first peak PCT values, which are dominated by the amount of stored energy assumed, as documented in Reference 2. The core remains covered throughout the LOCA event, so there is no second peak PCT.

RESPONSE 440.103

The ATWS rule contained in 10 CFR 50.62 specifies that:

a. Each BWR must have an ARI system that is diverse (from the reactor trip system) from sensor output to the final actuation device.

b. Each BWR must have a SLCS with a minimum flow capacity and boron content equivalent in control capacity to 86 gpm of 13 weight percent sodium pentaborate solution for a 251-inch RPV. For new plants, the SLCS initiation must be automatic.

c. Each BWR must provide equipment to trip the reactor coolant circulating pumps automatically under conditions indicative of an ATWS.

These requirements were derived from evaluations of BWR designs with locking-piston control rod drives (LPCRD), which use a hydraulic system to provide normal rod movement and scram functions. For ABWR, fine motion control rod drives (FMCRD) are used. These drives use a hydraulic system to provide the scram function, and an electric-driven system to provide normal rod motions. These two systems are independent from each other. Such a control rod drive design is not covered by the ATWS rule. Therefore, we have to go back to the design philosophy which led to the ATWS rule. For ATWS prevention/mitigation for ABWR, the following are provided:

a. An ARI system that utilizes sensors and logic which are diverse and independent of the reactor protection system,

b. Electrical insertions of FMCRD's that also utilizes sensors and logic which are diverse and independent of the reactor protection system, and

c. Automatic recirculation pump trip under conditions indicative of an ATWS.

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~~The use of FMCRD eliminates the common mode failure potentials of LPCRD by eliminating the scram discharge volume (mechanical common mode failure potential) and by having an electric motor run-in diverse from the hydraulic scram feature. In addition, since the probability of simultaneous failure of a large number of drives is very low, a failure to achieve shutdown is deemed incredible. Therefore, the ATWS design for ABWR meets the intent of the ATWS rule of 10 CFR 50.62.~~

~~The manual SLCS system is designed to meet requirements specified in 10 CFR 50 Appendix A and is described in Subsection 9.3.5.~~

~~Section 15.8 has been revised to include ARI and FMCRD electrical insertions as part of ATWS protection/mitigation.~~

QUESTION 440.104

In the ABWR design, SLCS pump is started manually. But the ATWS rule 10 CFR 50.62 states that "The SLCS initiation must be automatic and must be designed to perform its function in a reliable manner for plants granted construction permits after July 26, 1984." How does the ABWR design satisfies the ATWS rule? (9.3.5)

RESPONSE 440.104

See response to Question 440.103

K

In addition, a manual SLCS is provided as a backup of ATWS mitigation. This system is designed to meet requirements specified in 10CFR50 Appendix A and is described in Subsection 9.3.5.

In summary, The following table shows compliance with specific aspects of the ATWS rule, 10CFR50.62, for the ABWR design:

ATWS Rule	ABWR Design
1. Diverse scram system	1. Diverse ARI is provided.
2. Automatic SLCS injection	2a. Diverse and automatic FMCRD run-in is provided.
	2b. Backup manual SLCS injection is provided.
3. Automatic RPT	3. Automatic RPT is provided.

The ARI design follows the guidelines for the design objectives and design basis requirements for the ARI system as documented in NEDE-31096-P-A (ATWS, Response to NRC ATWS Rule 10CFR50.62, approved by the NRC in October, 1986). The ABWR ATWS trip logic, as shown in the attached Figure 440.103-1, is highly reliable and single-failure-proof.

In addition, the ABWR design eliminates the scram discharge volume, and, therefore, eliminates an identified common mode failure potential of the existing locking-piston CRDs. The implementation of the diverse and automatic FMCRD run-in as a backup of the ARI system further reduces the probability of an ATWS. It is estimated that the need of boron injection is reduced by at least a factor of 100. This means that the need of boron injection is less than 10^{-8}/year. A quantitative probabilistic analysis is presented in Appendix 19D of the SSAR. (See Tables 19D.4-18 and 19D.4-1 and Subsection 19D.6.5.1 through 19D.6.5.5.) Therefore, it is concluded that an automatic boron injection is not necessary. A manual boron injection as a backup is thus acceptable.

In order to further justify the acceptability of the ABWR design, performance analyses were performed for the most limiting ATWS event (i.e.; all MSIV closure event). The analysis results together with the acceptance criteria are shown in the following:

(K) CONTINUED

System Parameter	Criteria	With ARI	With FMCRD Run-in
Peak RPV Pressure (psig)	1500	1336	1336
Peak Pool Temp (F)	207	142	152
Fuel Integrity	Coolable Geometry	Met	Met
Peak Containment Pressure (psig)	45	3.7	4.7

It is concluded from above analysis results that both the ARI and the FMCRD run-in could mitigate the most limiting ATWS event. Thus, the ABWR design does not need an SLCS to respond to an ATWS threatening event.

In order to further demonstrate the capability of the ABWR, additional analyses with the assumption that both ARI and FMCRD run-in fail (i.e.; with additional multiple failures) were performed. In these analyses, it is assumed that the operator follows the emergency procedure guidelines (EPG) to manually initiate the boron injection when the suppression temperature reaches the preset limit (e.g.; 135°F). The time that the suppression pool temperature reaches 135°F depends upon the initial suppression pool temperature and the severity of the ATWS event, which depends on the void coefficient, event type, etc.. It is estimated that this time interval is in the range from about 90 seconds to many minutes. In the analyses shown below, it is assumed that the boron injection is initiated at about 90 seconds after the closure of all MSIVs. It is also assumed that the boron starts to enter the vessel 2 minutes after the initiation. The analysis results together with the acceptance criteria are shown in the following:

System Parameter	Criteria	With One SLC Pump	With Two SLC Pumps
Peak RPV Pressure (psig)	1500	1335	1335
Peak Pool Temp (F)	Containment Design Pressure*	240 (Met)	206 (Met)
Fuel Integrity	Coolable Geometry	Met	Met
Peak Containment Pressure (psig)	45	30.0	15.2

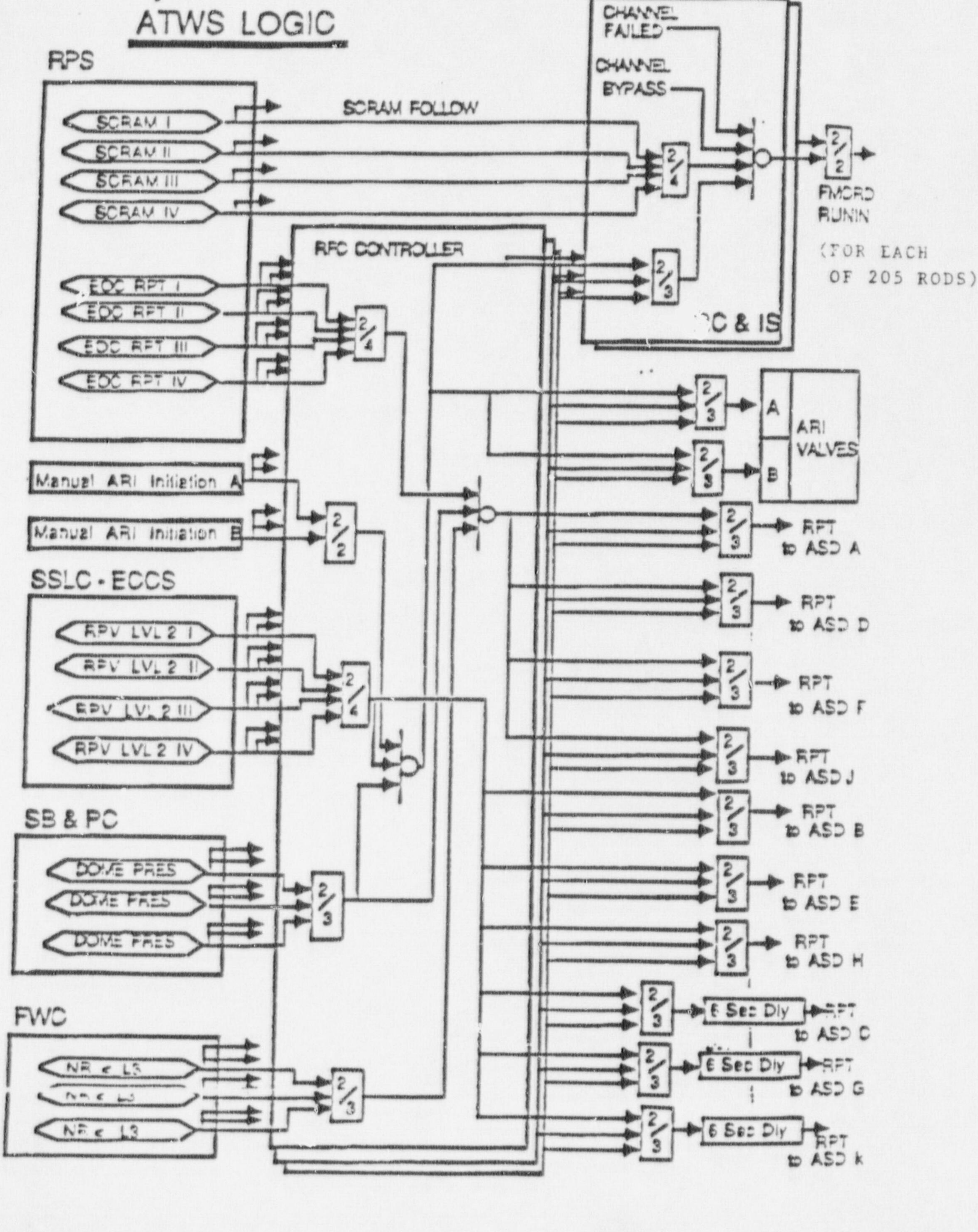
* Criterion for ATWS with additional multiple failures.

K (CONTINUED)

It is concluded from above analysis results that manual boron injection with either one or two SLC pumps could mitigate the most limiting ATWS event with margin (at least 15 psi margin in peak containment pressure). From this margin, it is estimated that the operator has about 10 minutes to inject the boron into the vessel in order to maintain the containment integrity following an ATWS event. Therefore, a manual SLCS injection (even with one pump) as a backup for ATWS mitigation is acceptable.

(K) (CONTINUED)

Figure 440.103-1



TMI ACTION PLAN ITEMS

and engineered safeguards systems.

(4) Fuel-zone, water-level range: This range used for its RPV taps the elevation above the main steam outlet nozzle and the taps just above the internal recirculation pump (RIP) deck. The zero of the instrument is the bottom of the active fuel and the instruments are calibrated to be accurate at 0 psig and saturated condition. The water- level measurement design is the condensate reference type, is not density compensated, and uses differential pressure devices as its primary elements. These instruments provide input to water-level indication only.

There are common condensate reference chambers for the narrow-range; wide-range; and fuel-zone, water-level ranges.

The elevation drop from RPV penetration to the drywell penetration is uniform for the narrow range and wide range water-level instrument lines in order to minimize the change in water-level with changes in drywell temperature.

Reactor water-level instrumentation that initiates safety systems and engineered safeguards is shown in Figure 5.1-3.

NEW

1A.2.21.1 Failure of PORV or Safety to Close (II.K.3.3)

NRC Position

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report. This requirement is to be met before fuel load.

Response

See Subsection 1A.3.4 for interface requirement.

1A.2.22.2 Separation of HPCI AND RCIC System Initiation Levels [II.K.3(13)]

NRC Position

Currently, the reactor core isolation cooling (RCIC) system and the high-pressure coolant injection (HPCI) systems both initiate on the same low-water-level signal and both isolate on the same high-water-level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the initiation logic of the RCIC system should be modified so that the RCIC system will restart on low water level. These changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analysis should be submitted to the NRC staff and changes should be implemented if justified by the analysis.

Response

The ABWR Standard Plant design is consistent with this position. The high pressure core flooder (HPCF) system is initiated at Level 1-1/2, and the RCIC system is initiated at Level 2. At Level 8, the injection valves for the HPCF and the RCIC steam supply and injection valves will automatically close in order to prevent water from entering the main steam lines.

In the unlikely event that a subsequent low level recurs, the RCIC steam supply and injection valves will automatically reopen to allow continued flooding of the vessel. The HPCF injection valves will also automatically reopen unless the operator previously closed them manually. Refer to Subsections 7.3.1.1.1.1 (HPCF) and 7.3.1.1.1.3 (RCIC) for additional details regarding system initiation and isolation logic.

1A.2.23 Modify Break-Detection Logic to Prevent Spurious Isolation of HPCI And RCIC Systems [II.K.3(15)]

NRC Position

The high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe-break-detection circuitry has resulted in spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe-break- detection circuitry should be modified to switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Response

The RCIC system provided in the ABWR Standard Plant includes an automatic switchover feature which will change the pump suction source from the RCIC storage pool to the suppression pool. The safety-grade switchover will automatically occur upon receipt of a low-level signal from the condensate storage pool or a high-level signal from the suppression pool.

See Subsection 7.3.1.1.1.3 for additional information.

1A.2.29 Confirm Adequacy of Space Cooling for High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems [II.K.3(24)]

NRC Position

Long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems may require space cooling to maintain the pump-room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of alternating-current power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite alternating-current power to their support systems, including coolers, for at least 2 hours.

Response

REVISED

The ABWR high pressure core flooder (HPCF) and the reactor core isolation cooling (RCIC) systems are provided space cooling via individual room safety grade air-coditioning systems (See Subsection 9.4.5). If all offsite power is lost, space cooling for the HPCF and RCIC system equipment would not be lost because the motor power supply for each system is from seperate essential power supplies.

1A.2.32 Revised Small-Break Loss-of-Coolant-Accident Methods to Show Compliance with 10 CFR PART 50, Appendix K [II.K.3(30)]

NRC Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Response

GE has evaluated the NRC request requiring that the BWR small-break LOCA analysis methods are to be demonstrated to be in compliance with Appendix K to 10 CFR 50 or that they be brought into compliance by analysis methods changes. The specific NRC concerns are contained in NUREG-0626, Appendix F. The specific NRC concerns identified in Subsection 4.2.10 of NUREG-0626 (Appendix F) relate to the following: counter current flow limiting (CCFL) effects, core bypass modeling, pressure variation in the reactor pressure vessel, integral experimental verification, quantification of uncertainties in predictions, the recirculation line inventory modeling, and the homogeneous/equilibrium model.

The response to the NRC small break model concerns was provided at a meeting between the NRC and GE on June 18, 1981. Information provided at this meeting showed that, based on the TLTA small break test results and sensitivity studies, the existing GE small break LOCA model already satisfies the concerns of NUREG-0626 and is in compliance with 10 CFR 50, Appendix K. Therefore, the GE model is acceptable relative to the concerns of Item II.K.3(30), and no model changes need be made to satisfy this item.

Documentation of the information provided at the June 18, 1981 meeting was provided via the letter from R. H. Buchholz (GE) to D. G. Eisenhut (NRC), dated June 26, 1981.

1A.2.33.1 Plant-Specific Calculations to Show Compliance with 10 CFR Part 50.46 [II.K.3(31)]

NRC Position

Plant-specific calculations using NRC-approved models for small-break loss-of-collant accidents (LOCAs) as described in Item II.K.3.30 to show compliance with 10 CFR 50.46 should be submitted for NRC approval by all licensees.

Response

The ABWR standard safety small-break LOCA calculations are discussed in Subsection 6.3.3.7.

The references listed in Subsection 6.3.6 describe the currently approved Appendix K methodology used to perform these calculations. Compliance with 10CFR50.46 has previously been established for that methodology.

Since, as noted in the previous Item (1A.2.32), no model changes are needed to satisfy NUREG-0737, Item II.K.3(30), there is no need to revise the calculations presented in Subsection 6.3.3.7.

1A.2.33.2 Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure [II.K.3 (44)]

NRC Position

For anticipated transients combined with the worst single failure and assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which in a stuck-open relief valve should be included in this category. The results of the evaluation are due January 1, 1981.

NEW

Response

GE and the BWR Owners' Group have concluded, based on a representative BWR/6 plant study, that all anticipated transients in Regulatory Guide 1.70, Revision 3, combined with the worst single failure, the reactor core remains covered with water until stable conditions are achieved. Futhermore, even with more degraded conditions involving a stuck-open relief valve in addition to the worsttransient (loss of feedwater) and worst single failure (failure of high pressure core spray), studies show (NEDO-24708, March 31, 1980) that the core remains covered and adequate core cooling is available during the whole course of the transient. The conclusion is applicable to the ABWR. Since the ABWR has more high pressure make-up systems (2HPCFs and 1 RCIC), the core covering is further assured.

Other discussions of transients with single failure is presented in the response to NRC Question 440.111.

NEW

1A.2.33.3 Evaluate Depressurization other than Full ADS [II.K.3 (45)]

NRC Position

Provide an evaluation of depressurization methods other than by full actuation of the automatic depressurization system, that would reduce the possibility of exceeding vessel integrity limits during rapid cooldown. (Applicable to BWR's only)

Response

This response is provided in Subsection 19A.2.11

NEW

1A.2.33.4 Responding to Michelson Concerns [II.K.3 (46)]

NRC Position

General Electric should a response to the Michelson concerns as they relate to boiling water reactors.

<u>Clarification</u>

General Electric provided a response to the Michelson concerns as they relate to boiling water reactors by letter dated February 21, 1980. Licensees and applicats should assess applicability and adequacy of this response to their plants.

Response

All of the generic February 21, 1980 GE responses are applicable to the ABWR design and are adequate in terms of a response to the Michelson concerns for the ABWR Standard Plant.

1A.2.34 Primary Coolant Sources Outside Containment Structure [III.D.1.1(1)]

NRC Position

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids duringa serious transient or accident to as-low-as-practical levels. This program shall include the following:

(1) Immediate leak reduction

(a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

(b) Measure actual leakage rates with systems in operation and report them to the NRC.

(2) Continuing Leak Reduction--establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This

1A.3 INTERFACES

1A.3.1 Emergency Procedures and Emergency Procedures Training Program

Emergency procedures, developed from the emergency procedures guidelines, shall be provided and implemented prior to fuel loading. (See Subsection 1A.2.1).

1A.3.2 Review and Modify Procedures for Removing Safety-Related Systems From Service

Procedures shall br reviewed and modified (as required) for removing safety-related systems from service (and restoring to service) to assure operability status is known. (See Subsection 1A.2.19)

1A.3.3 In Plant Radiation Monitoring

Equipment and training and procedures shall be provided for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during the accident. (See Subsection 1A.2.18)

1A.3.4 Reporting Failures of Reactor System Relief Valves

Failures of reactor system relief valves shall be reported in the annual report to the NRC. (See Subsection 1A.2.3.21.1).

1A.3.5 Report or ECCS Outages

NEW

Starting from the date of commercial operations, an annual report should be submitted which includes instance of emergency core cooling system unavailability because of component failure, maintenance outage (both forced or planned), or testing, the following information shall be collected:

(1) Outage date
(2) Duration of outage
(3) Cause of outage
(4) Emergency core cooling system or component involved
(5) Corrective action taken

The above information shall be assembled into a report, which will also include a discussion of any changes, proposed or implemented, deemed appropiate, to improve the availability of the emergency core cooling equipment.

ATTACHMENT 2

NEW CHAPTER 15 ANALYSES

AND

ADDITIONAL JUSTIFICATION OF EVENT CLASSIFICATION

NEW CHAPTER 15 ANALYSIS

GE will provide new analyses for the following events to reflect the implementation of the M-G sets described herein:

(1) Loss of offsite power, and

(2) Trip of pumps.

ADDITIONAL JUSTIFICATION OF EVENT CLASSIFICATION

GE will provide additional justification of the classification for the following events:

Category	Event
Decrease in coolant temperature	Runout of two feedwater pumps Opening of all control and bypass valves Pressure regulator downscale failure
Increase in reactor pressure	Generator load rejection, failure of one bypass valve Generator load rejection with bypass off Turbine trip with failure of one bypass valve Turbine trip with bypass off
Decrease in coolant system flow	Fast runback of all reactor internal pumps
Increase in reactor coolant inventory	Inadvertent HPCF pump start-up

ABWR MOTOR-GENERATOR SETS

Two motor-generator (MG) sets, located on the top floor of the control building (SSAR Figures 1.2-15 and 1.2-21), are provided as part of the reactor internal pump (RIP) power supply system for extending the coast down time of the connected RIPs. Each MG set receives input power from an independent 6.9 kV power bus and provides constant 6.9 kV output to three adjustable speed drives (See SSAR Figure 8.3-1). Included in each MG set are: (a) an induction motor which drives the MG set at constant speed; (b) an AC synchronous generator and its associated excitation system (brushless type); (c) a flywheel for adding inertia to extend the coast down time of RIP during a bus failure transient; and (d) control and protection circuits.

The MG set inertia is sized such that RIP speed will be maintained for at least three seconds after the loss of bus power. Within these 3 seconds, the power from the MG set coastdown is capable of maintaining RIP speed at 100% of rated for at least the first second, and then maintain the rate of RIP speed reduction to less than 10% per second for the remaining two seconds.

ATTACHMENT 3

UPDATE OF SUBSECTION 5.4.5

"MAIN STEAMLINE ISOLATION SYSTEM"

steamline break. The maximum differential pressure is conservatively assumed to be 1375 psi, the reactor vessel ASME Code limit pressure.

The ratio of venturi throat diameter to steamline inside diameter of approximately 0.5 results in a maximum pressure differential (unrecovered pressure) of about 14 psi at 100% of rated flow. This design limits the steam flow in a severed line to less than 200% rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the main steamline isolation valves when the steam flow exceeds preselected operational limits. The vessel dome pressure and the venturi throat pressure are used as the high and low flow sensing locations.

5.4.4.3 Safety Evaluation

In the event a main steamline should break outside the containment the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 200% of the rated value. Prior to isolation valve closure, the total coolant losses from the vessel are not sufficient to cause core uncovering and the core is thus adequately cooled at all times.

Analysis of the steamline rupture accident (Subsection 15.6.4) shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steamline break does not exceed the guideline values of published regulations.

Tests on a scale model determined final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, unrecoverable losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.

The steam flow restrictor is exposed to steam of about 2/10% moisture flowing at velocities of 150 ft/sec (steam piping ID) to 600 ft/sec (steam restrictor throat). ASTM A351 Type 304 cast stainless steel was selected for the steam flow restrictor material because it has excellent resistance to erosion/corrosion in a high velocity steam atmosphere. The excellent performance of stainless steel in high velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel which prevents any surface attack and this film is not removed by the steam.

Hardness has no significant effect on erosion/corrosion. For example hardened carbon steel or alloy steel will erode rapidly in applications where soft stainless steel is unaffected.

Surface finish has a minor effect on erosion/corrosion. If very rough surfaces are exposed, the protruding ridges or points will erode more rapidly than a smooth surface. Experience shows that a machined or a ground surface is sufficiently smooth and that no detrimental erosion will occur.

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the RPV steam outlet nozzle and has no moving components, no testing program beyond the RPV inservice inspection is planned. Very slow erosion which occurs with time, has been accounted for in the ASME, Section III design analysis. Stainless steel resistance to erosion has been substantiated by turbine inspections at the Dresden Unit 1 facility. These inspections have revealed no noticeable effects from erosion on the stainless steel nozzle partitions. The Dresden inlet velocities are about 300 ft/sec and the exit velocities are 600 to 900 ft/sec. However, calculations show that, even if the erosion rates are as high as 0.004 in. per year, after 40 years of operation, the increase in restrictor-choked flow rate would be no more than 5%. A 5% increase in the radiological dose calculated for the postulated main steamline break accident is insignificant.

5.4.5 Main Steamline Isolation System

5.4.5.1 Safety Design Bases

The main steamline isolation valves, individually or collectively, shall:

(1) close the main steamlines within the time established by design basis accident analysis to limit the release of reactor coolant;

(2) close the main steamlines slowly enough that simultaneous closure of all steam lines will not induce transients that exceed the nuclear system design limits;

(3) close the main steamline when required despite single failure in either valve or in the associated controls to provide a high level of reliability for the safety function;

(4) use pneumatic (N_2 or air) pressure and/or spring force as the motive force to close the redundant isolation valves in the individual steamlines.

(5) use local stored energy (pneumatic pressure and/or springs) to close at least one isolation valve in each steam pipeline without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure;

(6) be able to close the steamlines, either during or after seismic loadings, to assure isolation if the nuclear system is breached; and

(7) have the capability for testing during normal operating conditions to demonstrate that the valves will function.

5.4.5.2 Description

Two isolation valves are welded in a horizontal run of each of the four main steam pipes; one valve is as close as possible to the inside of the drywell, and the other is just outside the containment.

Figure 5.4-7 shows a main steamline isolation valve. Each is a Y-pattern, globe valve. Rated steam flow through each valve is 4.23×10^6 lb/hr. The main disc or poppet is attached to the lower end of the stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet greater than the seat port area. The poppet travels approximately 90% of the valve stem travel to close the main steam port area; approximately the last 10% of the valve stem travel closes the pilot valve. The air cylinder actuator can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A Y-pattern valve permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent debris blockage.

The valve stem penetrates the valve bonnet through a stuffing box that has two sets of replaceable packing. A lantern ring and leak-off drain are located between the two sets of packing.

Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston.

Valve quick-closing speed is 3-4.5 seconds when N_2 or air is admitted to the upper piston compartment. The valve can be test closed with a 45-60 second slow closing speed by admitting N_2 or air to both the upper and lower piston compartments.

The pneumatic cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts close the valve if gas pressure is not available. The motion of the spring seat member actuates switches in the near open, near closed vavle positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the gas cylinder. This unit contains three types of control valves that open and close the main valve and excercise it at slow speed: pnuematic, a-c from Division I, and a-c from Division II. Remote manual switches in the control room enable the operator to operate the valves.

Operating gas is supplied to the valves from the plant N_2 or air system. An pnuematic accumulator between the control valve and a check valve provides backup operating gas.

Each valve is designed to accommodate saturated steam at plant operating conditions with a moisture content of approximately 0.25%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The valves are furnished in conformance with a design pressure and temperature rating in excess of plant operating conditions to accommodate plant overpressure conditions.

In the worst case, if the main steamline should rupture downstream of the valve, steam flow would quickly increase to 200% of rated flow. Further increase is prevented by the venturi flow restrictor.

During approximately the first 75% of closing, the valve has little effect on flow reduction, because the flow is choked by the venturi restrictor. After the valve is approximately 75% closed, flow is reduced as a function of the valve area versus travel characteristic.

The design objective for the valve is a minimum of 60 years service at the specified operating conditions. Operating cycles (excluding exercise cycles) are estimated to be 1000 cycles in 60 years and 2500 execise cycles in 60 years.

In addition to minimum wall thickness required by applicable codes, a corrosion allowance is added to provide for 60 years service.

Design specification ambient conditions for normal plant operation are 135°F normal temperature and 60% humidity in a radiation field of 202 rad/hr neutron plus gamma, continuous for design life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

The main steamline isolation valves are designed to close under accident environmental conditions of 340°F for one hour at drywell design pressure. In addition, they are designed to remain closed under the following post-accident environment conditions:

(1) 340°F for an additional 2 hours at drywell drywell pressure of 45 psig,

(2) 320°F for an additional 3 hours at drywell design pressure of 45 psig,

(3) 250°F for an additional 18 hours at 25 psig maximum, and

(4) 200°F for an additional 99 days at 20 psig.

To resist sufficiently the response motion from the safe shutdown earthquake, the main steam line valve installations are designed as Seismic Category I equipment. The valve assembly is manufactured to withstand the safe shutdown earthquake forces applied at the mass center of the valve with the valve located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously. The stresses caused by seismic loads are combined with the stresses caused by other live and dead loads including the operating loads. The allowable stress or this combination of loads is based on a percentage of the allowable yield stress for the material. The parts of the main steam isolation valves that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Code Section III.

5.4.5.3 Safety Evaluation

In a direct cycle nuclear power plant the reactor steam goes to the turbine and to other equipment outside the containment. Radioactive materials in the steam are released to the environs through process openings in the steam system or escape from accidental openings. A large break in the steam system can drain the water from the reactor vessel faster than it is replaced by feedwater.

The analysis of a complete, sudden steamline break outside the containment is described in Subsection 15.6.4. The analysis shows that the fuel barrier is protected against loss of cooling if main steam isolation valve closure is within specified limits, including instrumentation delay to initiate valve closure after the break. The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (approximately 3 seconds) of the main steam isolation valves is also shown to be satisfactory. The switches on the valves initiate reactor scram when specific conditions (extent of valve closure, number of pipe lines included, and reactor power level) are exceeded (Subsection 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear SRVs to open briefly, but the rise in fuel cladding temperature will be insignificant. No fuel damage results.

The ability of this Y-pattern globe valve to close in a few seconds after a steamline break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full-size, 20-inch valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Reference 1).

The following specified hydrostatic, leakage, and stroking tests, as a minimum, are performed by the valve manufacturer in shop tests:

(1) To verify its capability to close at settings between 3 and 4.5 sec (response time for full closure is set prior to plant operation at 3.0 sec minimum, 4.5 sec maximum), each valve is tested at rated pressure (1000 psig) and no flow.

(2) Leakage is measured with the valve seated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/hr/in. of nominal valve size. In addition, an air seat leakage test is conducted using 40 psi pressure upstream. Maximum permissible leakage is 0.1 scfh/in. of nominal valve size.

(3) Each valve is hydrostatically tested in accordance with the requirements of the applicable edition and addenda of the ASME Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. Tests include radiographic, liquid- penetrant, or magnetic-particle examinations of casting, forgings, welds, hardfacings, and bolts

After the valves are installed in the nuclear system, each valve is tested as discussed in Chapter 14.

Two isolation valves provide redundancy in each steamline so either can perform the isolation function and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and the respective control systems are separated physically.

The isolation valve is analyzed and tested for earthquake loading. The loading caused by the specified earthquake loading is required to be within allowable stress limits and with no malfunctions that would prevent the valve from closing as required.

Electrical equipment that is associated with the isolation valves and operated in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The expected pressure and temperature transients following an accident are discussed in Chapter 15.

5.4.5.4 Inspection and Testing

The main steam isolation valves can be functionally tested for operability during plant operation and refueling outages. The test provisions are listed below. During refueling outage the main steam isolation valves can be functionally tested, leak-tested, and visually inspected.

The main steamline isolation valves can be tested and exercised individually to the 90% open position in the slow closing mode.

Leakage from the valve stem packing is collected and measured by the drywell drain system. During shutdown while the nuclear system is pressurized, the leak rate through the inner valve stem packings can be measured by collecting and timing the leakage.

The leak through the pipeline valve seats can be measured accurately during shutdown by the following suggested procedure:

(1) With the reactor at approximately 125°F and normal water level and decay heat being removed by the RHR system in the shutdown cooling mode, all main steam isolation valves are closed utilizing both spring force and air pressure on the operating cylinder.

(2) Nitrogen is introduced into the reactor vessel above normal water level and into the connecting main steamlines and pressure is raised to 20-30 psig. An alternate means of pressurizing the upstream side of the inside isolation valve is to utilize a steamline plug capable of accepting the 20 to 30 psig pressure acting in a direction opposite the hydrostatic pressure of the fully flooded reactor vessel.

(3) A pressure gage and flow meter are connected to the test tap between each set of main steam isolation valves. Pressure is held below 1 psig, and flow out of the space between each set of valves is measured to establish the leak rate of the inside isolation valve.

(4) To leak check the outer isolation valve, the reactor and connecting steamlines are flooded to a water level that gives a hydrostatic head at the inlet to the inner isolation valves slightly higher than the pneumatic test pressure to be applied between the valves. This assures essentially zero leakage through the inner valves. If necessary to achieve the desired water pressure at the inlet to the inner isolation valves, gas from a suitable pneumatic supply is introduced into the reactor vessel top head. Nitrogen pressure (20 to 30 psig) is then applied to the space between the isolation valves. The stem packing is checked for leak tightness. Once any detectable stem packing leakage to the drain system has been accounted for, the seat leakage test is conducted by shutting off the pressurizing gas and observing any pressure decay. The volume between the closed valves is accurately known. Correction for temperature variation during the test period are made, if necessary, to obtain the required accuracy. Pressure and temperature are recorded over a long enough period to obtain meaningful data. An alternate means of leak testing the outer isolation valve is to utilize the previously noted steamline plug and to determine leakage by pressure decay or by inflow of the test medium to maintain the specific test pressure.

During pre-startup tests following an extensive shutdown, the valves will receive the same hydro tests that are imposed on the primary system.

Such a test and leakage measurement program ensures that the valves are operating correctly.

5.4.6 Reactor Core Isolation Cooling System

Evaluations of the reactor core isolation cooling system against the applicable General Design Criteria are provided in Subsection 3.1.2. 440.45

5.4.6.1 Design Basis

The reactor core isolation cooling (RCIC) system is a safety system which consists of a turbine, pump, piping, valves, accessories, and instrumentation designed to assure that sufficient reactor water inventory is maintained in the reactor vessel to permit adequate core cooling to take place. This prevents reactor fuel overheating during the following conditions:

(1) a loss-of-coolant (LOCA) event;

(2) vessel isolated and maintained at hot standby;

(3) vessel isolated and accompanied by loss of coolant flow from the reactor feedwater system;

(4) complete plant shutdown with loss of normal feedwater before the reactor is depressurized to a level where the shutdown cooling system can be placed in operation; or

(5) loss of AC power for 30 minutes.

Acceptence criteria II.3 of SRP Section 5.4.6 states that the RCIC system must perform its function without the availability of any a-c power. Review Procedure III.7 further requires

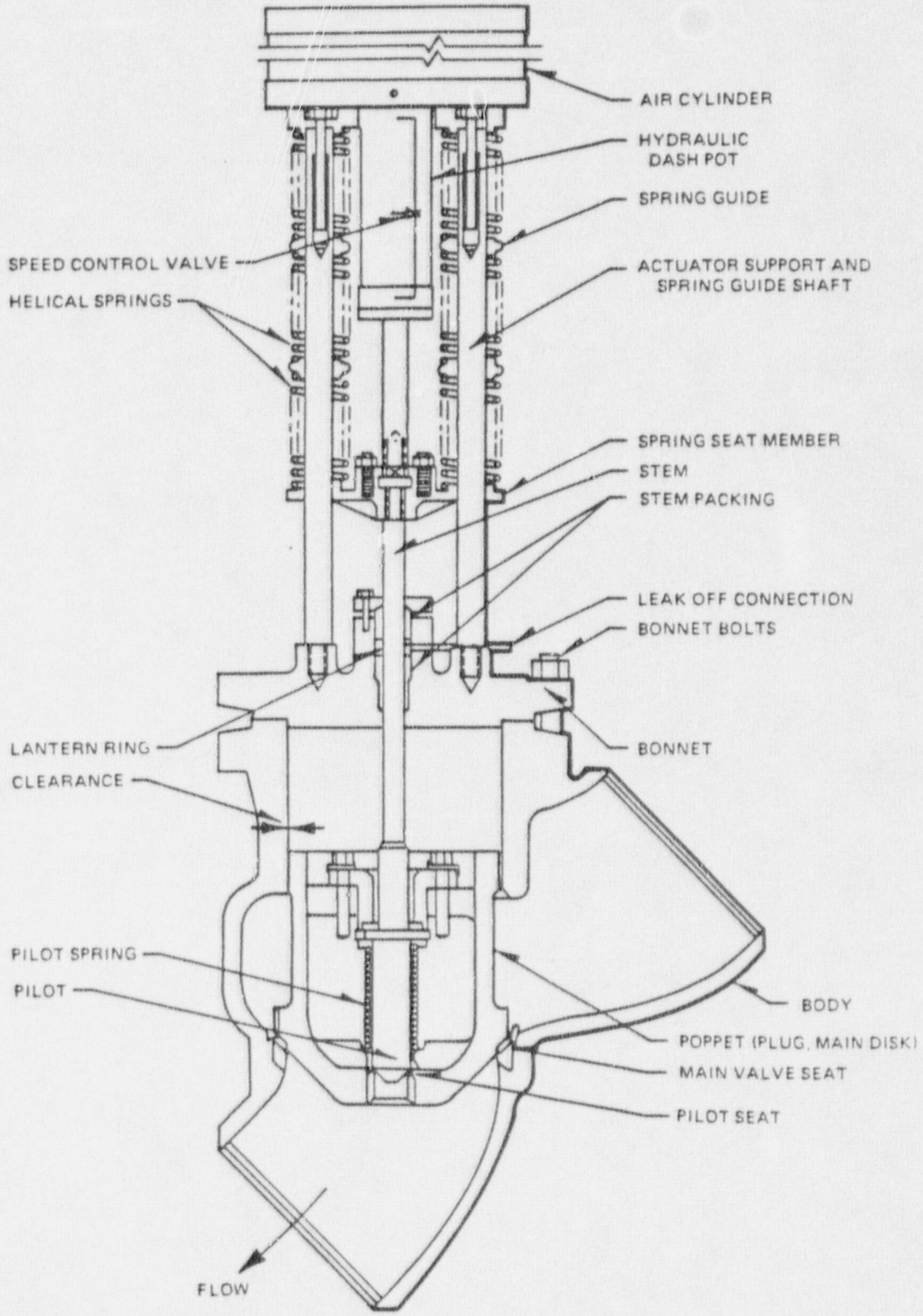


Figure 5.4-7 MAIN STEAM ISOLATION VALVE